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# REGIONAL HAZE REASONABLE PROGRESS ANALYSIS

## Oxbow Calcining LLC
## Kremlin Calcined Coke Plant

Presented To:

**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY**

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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]

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[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.

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[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

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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**

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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.

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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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# APPENDIXES

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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.

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# 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<br>Stack = -1.0 to -1.2 | Combustion Chamber = -0.2 to -0.4<br>Stack = -1.0 to -1.2 | Combustion Chamber = -0.2 to -0.4<br>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, 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

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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.

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[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

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[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).

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.

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]

[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).

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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.

[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 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

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- 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.

**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.*

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## 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").

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.

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- 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.

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### 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 |

| 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.

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**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 |

# 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.

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# 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).

# 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 (ton/year) | Emission Rate (lb/hr) | Expected Emissions Reduction (ton/year) | Control Efficiency (%) | Expected Emissions (ton/year) | Emission Rate (lb/hr) | Expected Emissions Reduction (ton/year) | Control Efficiency (%) | Expected Emissions (ton/year) | Emission Rate (lb/hr) | Expected Emissions Reduction (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 (tpy) | Tons of $SO_2$ Removed (tpy) | Total Capital Requirement ($) | Annualized Capital Cost ($/year) | Annualized Outage Cost ($/year) | Total Annual Operating Costs ($/year) | Total Annual Costs ($) | Average Cost Effectiveness ($/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 (tpy) | Tons of $SO_2$ Removed (tpy) | Total Capital Requirement ($) | Annualized Capital Cost ($/year) | Annualized Outage Cost ($/year) | Total Annual Operating Costs ($/year) | Total Annual Costs ($) | Average Cost Effectiveness ($/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 (tpy) | Tons of $SO_2$ Removed (tpy) | Total Capital Requirement ($) | Annualized Capital Cost ($/year) | Annualized Outage Cost ($/year) | Total Annual Operating Costs ($/year) | Total Annual Costs ($) | Average Cost Effectiveness ($/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 (tpy) | Tons of $SO_2$ Removed (tpy) | Total Capital Requirement ($) | Annualized Capital Cost ($/year) | Annualized Outage Cost ($/year) | Total Annual Operating Costs ($/year) | Total Annual Costs ($) | Average Cost Effectiveness ($/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 (tpy) | Tons of $SO_2$ Removed (tpy) | Total Capital Requirement ($) | Annualized Capital Cost ($/year) | Annualized Outage Cost ($/year) | Total Annual Operating Costs ($/year) | Total Annual Costs ($) | Average Cost Effectiveness ($/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 (tpy) | Tons of $SO_2$ Removed (tpy) | Total Capital Requirement ($) | Annualized Capital Cost ($/year) | Annualized Outage Cost ($/year) | Total Annual Operating Costs ($/year) | Total Annual Costs ($) | Average Cost Effectiveness ($/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** | **Unit 2** | **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
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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:

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

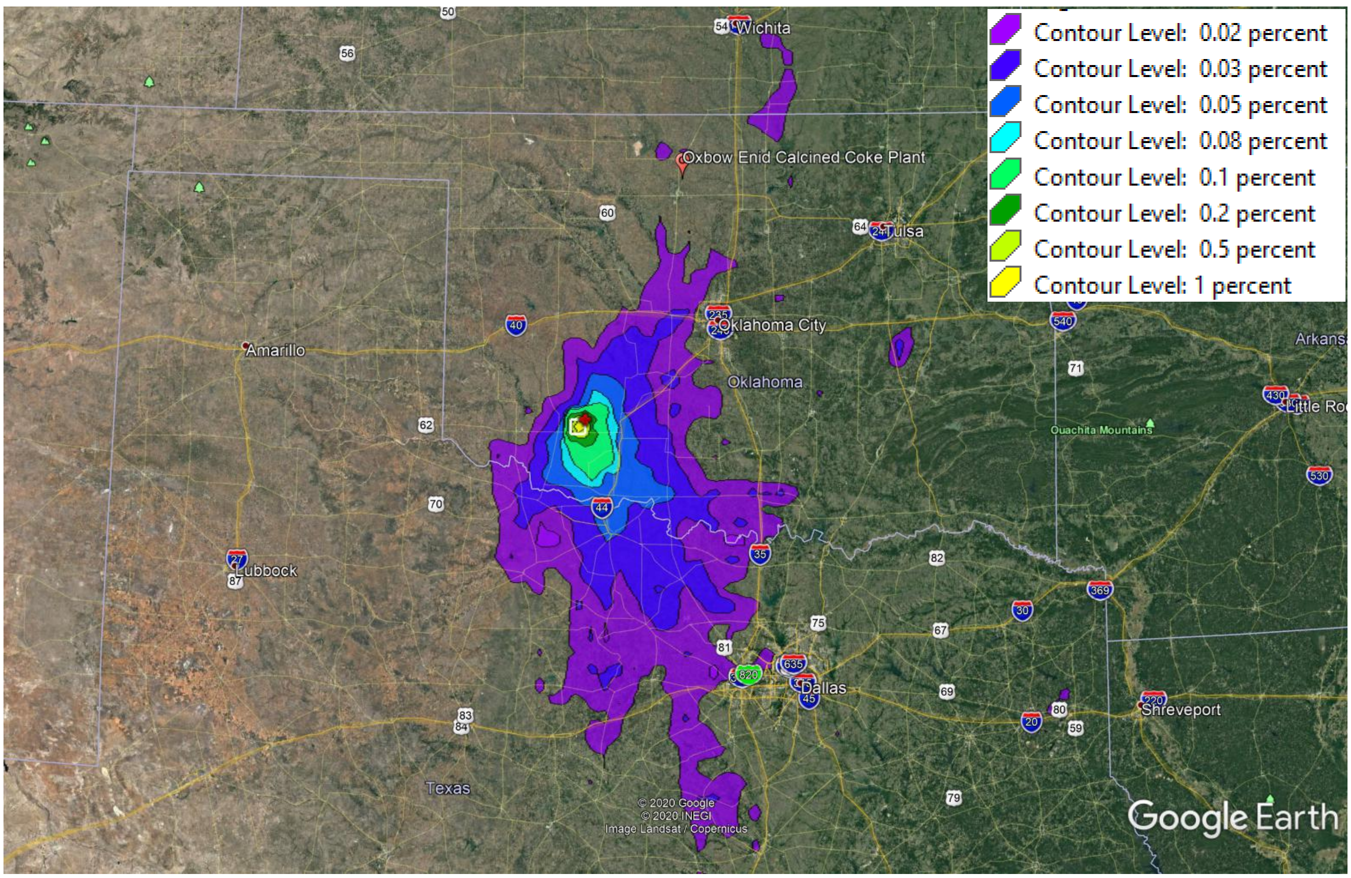
where T is the number of trajectory points that are located in a grid cell (i,j), and N is the total number of trajectory points analyzed.

[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:


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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.

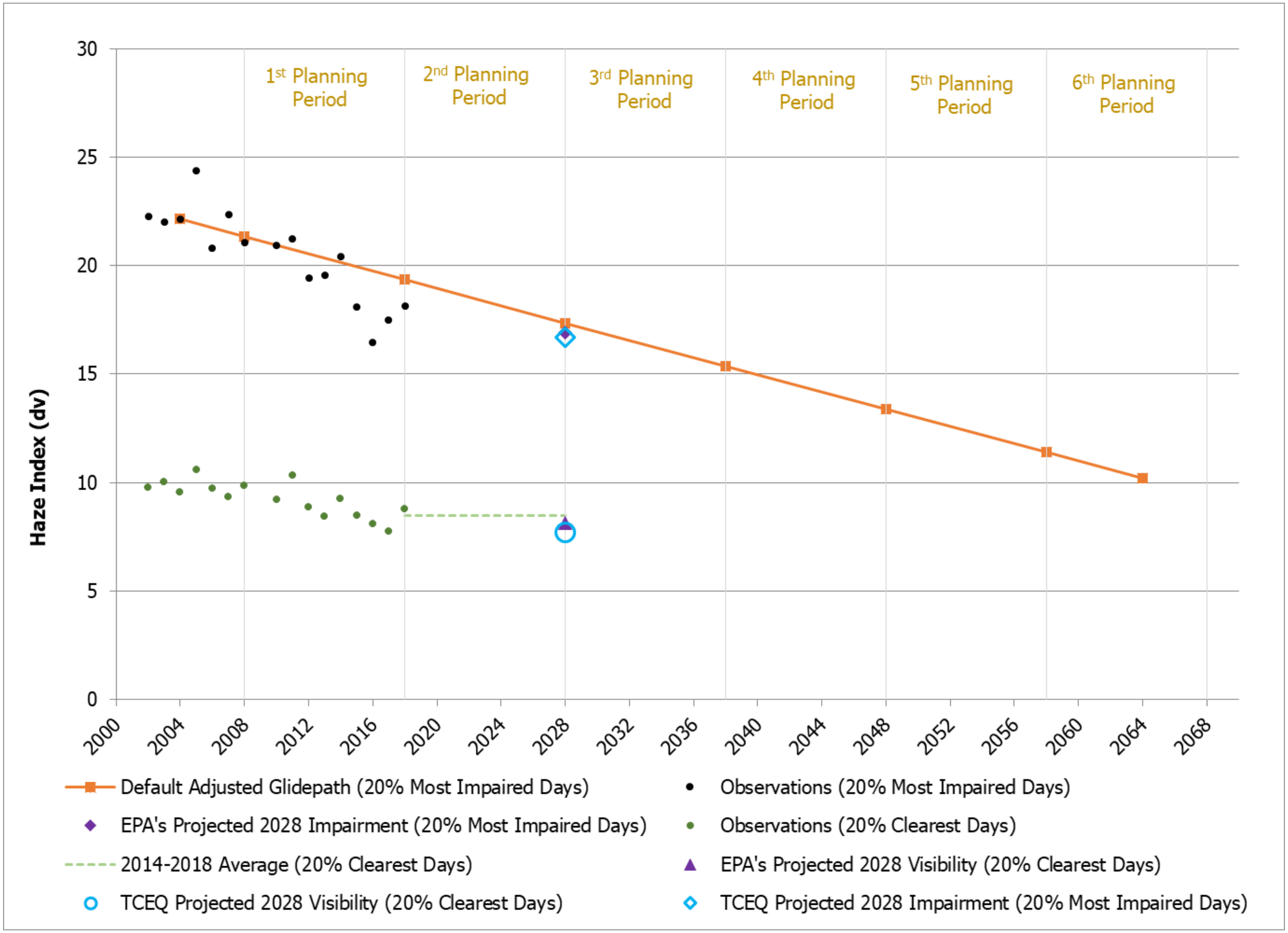
Figure 2-1 also shows the projected 2028 haze index values from the EPA 2028 Modeling TSD. EPA's modeling shows the projected 2028 haze index is three percent (3%) below the URP Glidepath. Therefore, if the EPA projected 2028 haze index values were adopted by ODEQ as the RPG in 2028 the objective of 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.