FINAL

FOUR FACTOR ANALYSIS

Grand River Energy Center Unit 2

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PREPARED FOR

Grand River Dam Authority

Grand River Dam Authority

8 SEPTEMBER 2020

BLACK & VEATCH

Reviewed by:

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

Signature

Sept 8, 2020

Date

Paul Lee

Printed Name

Reviewed by:

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

Signature

Sept 8, 2020

Date

Mark Bleckinger

Printed Name

Professional Engineer:

Signature

08Sep20

Date

LICENSED PROFESSIONAL ENGINEER
MONTY E. HINTZ
22927
STATE OF OKLAHOMA

Monty Hintz

Printed Name

22927

License No.

Approved by:

Signature

09/08/2020

Date

Kyle Lucas

Printed Name

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Acronym List

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

Executive Summary

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

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

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

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

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

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

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

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

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

1.0 Introduction

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

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

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

1.1 DEFINITION OF "FOUR-FACTOR ANALYSIS"

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

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

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

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

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

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

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

> The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering **the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment.** The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.

1.2 UNIT 2 FOUR FACTOR APPLICABILITY

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

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

1.2.1 SO_2 Emissions

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

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

1.2.2 Significant Emissions Impacts on Class I Areas

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

Q = 630 tons SO_2 emitted in 2016

D=~335 km from Wichita Mountains Wilderness Area

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

1.2.3 MATS Compliance

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

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

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

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

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

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

1.2.4 Summary

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

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

2.0 Plant Descriptions

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

2.1 GRAND RIVER ENERGY CENTER OVERVIEW

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

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

2.2 EMISSIONS DATA

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

Table 2-1 Unit 2 Emissions Limits

	EMISSIONS LIMITS	EMISSIONS 2019
SO_2	• 0.6 lb/MMBtu (permit condition) • 3,177 lb/h (permit condition) • 0.20 lb/MMBtu (Part 63, UUUUUU)	[redacted] lb/MMBtu [redacted] tons/yr)(1)

Notes:
1) The capacity factor for 2019 was % due to a force outage that lasted months.

3.0 Design Basis

3.1 FUEL

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

Table 3-1 Wyoming Design Coal

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

3.2 OPERATING PARAMETERS

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

Table 3-2 Operating Parameters for Unit 2 Boiler

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

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

Notes:

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

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

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

4.0 Four-Factor Analysis – SO_2

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

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

4.1 STEP 1: IDENTIFY ALL AVAILABLE TECHNOLOGIES

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

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

4.1.1 Coal Washing

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

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

4.1.2 Circulating Dry Scrubber

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

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

4.1.3 Dry Sorbent Injection

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

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

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

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

4.1.4 Pulse Jet Fabric Filter Upgrades

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

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

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

4.1.5 Spray Dryer Absorber Upgrades

Along with additional controls that can be installed at GREC Unit 2, modifications to the existing SDA system were evaluated in this study. The current system was designed to remove 85 percent of the incoming SO_2 based on the design information in Section 3, while burning coal with a sulfur content of up to [redacted] percent, so there is minimal potential for upgrades within the existing system to have a significant effect on SO_2 removal. Still, as part of the top-down approach, upgrades to the existing system were considered.

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

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

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

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

4.1.6 New Spray Dryer Absorber

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

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

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

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

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

4.1.7 Wet Flue Gas Desulfurization

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

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

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

4.2 STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

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

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

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

Table 4-1 Evaluation to Eliminate Control Options

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

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

4.3 STEP 3: EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

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

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

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

Table 4-2 Control Effectiveness for SO_2 Control Technologies

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

Notes:

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

4.4 STEP 4: EVALUATE FACTORS

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

4.4.1 Factor 1: Costs of Compliance

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

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

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

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

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

Table 4-3 SO_2 Control Technologies Costs and Effectiveness

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

4.4.2 Factor 2: Time Necessary for Compliance

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

Table 4-4 Time Necessary for Compliance in Months

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

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

4.4.3.1 Coal Cleaning

Energy Impacts of Compliance

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

Non-Air Quality Environmental Impacts of Compliance

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

4.4.3.2 Dry Sorbent Injection

Energy Impacts of Compliance

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

Non-Air Quality Environmental Impacts of Compliance

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

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

4.4.3.3 Circulating Dry Scrubber

Energy Impacts of Compliance

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

Non-Air Quality Environmental Impacts of Compliance

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

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

4.4.3.4 Spray Dryer Absorber

Energy Impacts of Compliance

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

Non-Air Quality Environmental Impacts of Compliance

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

4.4.3.5 Wet Flue Gas Desulfurization

Energy Impacts of Compliance

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

Non-Air Quality Environmental Impacts of Compliance

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

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

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

4.5 SUMMARY

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

Appendix A. Economic Criteria

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

Notes:

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