GP Cellulose™
growing smarter

Brunswick Cellulose, LLC

1400 West 9th Street (31520)
P.O. Box 1438
Brunswick, GA 31521
(912) 265-5780
www.gp.com

October 15, 2021

Mr. James Boylan
Georgia Environmental Protection Division
Air Protection Branch - Planning and Support Program
4244 International Parkway, Suite 120
Atlanta, GA 30354

Re: Brunswick Cellulose LLC
Facility AIRS No. 04-13-127-00003
Regional Haze Rule – 4-Factor Analysis

Dear Mr. Boylan:

On August 27, 2021, Brunswick Cellulose LLC received your request for additional information on the four-factor analysis (FFA) for sulfur dioxide (SO_2) submitted for the Brunswick Mill on November 30, 2020. Responses to the seven (7) specific items in your request are provided below and in the updated FFA attached to this letter.

1. ***Interest Rate:*** *EPA identified that the interest rate used in the four-factor analyses was 5 percent, which is cited in the Air Pollution Control Cost Manual (Cost Manual) as an example. EPA recommends that the facility use the current bank prime interest rate (default) or alternatively, use a firm-specific rate that is justified by the source. EPD suggests using the current bank prime interest rate and indicate in the calculations the specific date the interest rate was captured to illustrate that an appropriate and representative number was used.*

The interest rate used in the cost calculations for the FFA has been updated to the current bank prime interest rate of 3.25%. The revised cost calculations are included in the updated analysis attached to this letter.

2. ***Property Taxes:*** *EPA identified that property taxes are not typically included in a cost analysis unless additional property was purchased or there was a dramatic change to the property value. Unless Georgia Pacific can provide a justification for increased property value, EPD recommends removing property taxes from the cost calculations and update accordingly.*

Property taxes have been removed from the cost calculations included in the updated FFA attached to this letter.

3. ***Documenting Cost Basis:*** *As part of the cost analysis Georgia Pacific provided annual calculations for items like caustic, electricity, fresh-water usage, wastewater disposal that are a part of daily activities. EPA requested and EPD agrees that appropriate references, vendor quotes, accounting details need to be provided to justify the information being cited. In addition, Georgia Pacific did not include references for the cost estimate used for the Lime Kiln. EPD requests these references be added. If any of this information is deemed confidential in nature, EPD has Confidential Business Information (CBI) procedures.*

Site-specific cost data for caustic, electricity, and natural gas included in the cost effectiveness calculations are based on internal accounting data and are annual average values for 2019. These are obtained from GP accountants based on electronic billing data. There are no separate vendor quotes as these materials are already being used at the mill. Water usage and wastewater costs are based on the average of two nearby similar GP facilities as these are not direct billed.

The first reference for the scrubber cost estimate for the No. 4 Power Boiler has been revised to remove the information about the AFPA BE&K study and refer instead to the vendor quote received for the lime kiln scrubber that is the basis of this cost estimate. The control cost was developed by internal GP engineers in conjunction with Envitech (Scrubber Supplier) and is based on the following:

Venturi Scrubber-$600,000 each

Balance of plant (Ducting, Electrical, Controls, foundation, MCC)-$600,000

Installation and engineering - $1,200,000

Total cost-$2,400,000 per kiln

4. ***Calculation Method for O&M Costs:*** *EPA commented that it appeared that Georgia Pacific did not correctly use the referenced equation from the Sargent & Lundy study to calculate the Variable O&M costs for the Trona Injection (Appendix B, page 4). Specifically, the calculation of additional auxiliary power required shows that the value was multiplied by tons of* SO_2*. This was deemed erroneous. After a discussion with Georgia Pacific, it appears that Georgia Pacific changed the formula to equal dollars and not dollars per megawatt. The use of dollars is more appropriate for the calculating O&M costs and they are not typically done on a per megawatt basis. EPD would request that Georgia Pacific add clarifying statements to the cost tables in Appendix B to better explain the method they used and how they referenced the Sargent & Lundy study.*

The dry sorbent injection (DSI) cost calculations included in the original FFA follow the model used in Table 2 of the Sargent and Lundy study for a DSI system that precedes a fabric filter. The tables included in the original submittal match the format of the calculations in the Sargent and Lundy documentation and include all notes and other identifying information included in that document with one general exception. The Sargent and Lundy document calculates costs on a cost per power basis (e.g. $/MWh). Therefore, the calculations of all costs were altered slightly on the originally submitted FFA to account for the MWh of the No. 4 Power Boiler so that the end result of the calculations is just the cost. The units on the calculation of the cost of additional auxiliary power (identified as variable operating and maintenance costs for additional auxiliary power, or VOMP, in the Sargent and Lundy study) are \$/MWh when calculated using the equation shown in the Sargent and Lundy documentation directly. Therefore, the revised cost calculations included in the updated FFA attached to this letter have multiplied VOMP by the annual MWh power output of the No. 4 Power Boiler, rather than by the tons of SO_2 emitted by the boiler, to determine the total annual auxiliary power costs.

5. ***Update PB#4 Emissions Based on Corrected Emissions Inventory:*** *From previous discussions with Georgia Pacific, it was determined there was an error in the emissions calculations for Power Boiler #4. EPD requests that Georgia Pacific make sure that all data in the updated four-factor analysis reflects the corrected emissions.*

The revised cost effectiveness calculations in the updated FFA attached to this letter rely on the corrected SO_2 emission rates for the No. 4 Power Boiler rather than the emission rates submitted in past emission inventory reporting.

6. ***4-Factor Analysis for Fuel Oil:*** *EPD is still evaluating what the cost effectiveness threshold will be for the Regional Haze SIP. To be able to determine if a technology is cost effective, EPD needs some additional information in the 4-factor analysis for switching to a lower sulfur fuel or natural gas in the power boilers. EPD requests that any additional information pertaining to switching fuels be added to the analysis such as costs for updating burners, fuel systems and any limitations that the current system must undergo to be able to convert and burn a lower sulfur fuel oil such as No.2 or ULSD. Please discuss any other factors that would make this fuel switch not feasible as part of the four-factor analysis that have not been previously addressed. These additional factors can be energy requirements, non-air quality impacts or additional construction timelines. Any additional information that can be provided to allow EPD to perform a more thorough review of the four-factor analysis would be appreciated.*

Additional information on the cost effectiveness of firing No. 2 fuel oil in the emission units that currently fire No. 6 fuel oil at the site has been added to the attached FFA.

7. ***4-Factor Analysis for TDF:*** *After our discussion with Georgia Pacific on June 9, 2021, EPD is requesting a four-factor analysis for the use of Tire Derived Fuel (TDF). EPD would like Georgia Pacific to complete a four-factor analysis for TDF that specifically looks at replacing it, and the bark that is simultaneously burned with the TDF, with a lower sulfur fuel such as natural gas or fuel oil. EPD understands that the normal method of operation is to burn TDF along with bark that is a by-product of the pulping process. The TDF provides more heat content as combined with the bark, which is considered a wet fuel, thus it reduces the CO and balances combustion. In the analysis for TDF, EPD requests any emissions data that correlates the balance of combustion specifically CO or NOx CEMS data, or any other operational data that the facility can provide. This would help EPD put together a complete picture regarding the feasibility of replacing TDF as a fuel or if it is an essential part of the process. In addition, Georgia Pacific mentioned that the bark acts as a "scrubber" to help reduce emissions. If Georgia Pacific has any studies or known information that can correlate the percentage the bark reduces SO_2 emissions, then EPD requests that be submitted with the four-factor analysis and it can be used in the calculations. Otherwise, EPD would ask that Georgia Pacific assume zero scrubbing effect from the bark.*

Additional information on the cost effectiveness of replacing TDF with natural gas or No. 2 fuel oil has been added to the attached FFA.

As described in Section 2.3.1 of the attached FFA, bark is the primary fuel fired in the No. 4 Power Boiler. Bark is a low sulfur fuel on a lb/MMBtu basis; SO_2 emissions from bark combustion are relatively high because of the large quantity of bark burned in the boiler. For these reasons, and other reasons discussed in Section 2.3.1, GP does not believe that evaluation of the replacement of bark as the primary fuel in this boiler is warranted as part of the FFA. However, this fuel change has been included in Section 3.1.1.3 of the revised FFA to demonstrate that the change is not cost effective.

If you have any questions about the attached analysis, please do not hesitate to contact Jill Holmes at (912) 717-1768 or via email at Jill.Holmes@gapac.com.

Sincerely,

Gregory J Bosch

Gregory J. Bosch
Vice-President and General Manager
Brunswick Cellulose LLC

REGIONAL HAZE RULE – REASONABLE PROGRESS ANALYSIS

FOR

BRUNSWICK CELLULOSE LLC
FACILITY AIRS NO. 04-13-127-00003
1400 WEST NINTH STREET
BRUNSWICK, GLYNN COUNTY, GEORGIA

SUBMITTED TO THE
GEORGIA ENVIRONMENTAL PROTECTION DIVISION

NOVEMBER 2020, REVISED OCTOBER 2021

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

1.1. SOURCE INFORMATION 1-2
1.2. REPORT CONTENTS 1-3

2. AVAILABLE SO_2 CONTROL TECHNOLOGIES 2-1

2.1. CONTROL TECHNOLOGY OVERVIEW 2-1
2.2. GOOD OPERATING PRACTICES 2-1
2.3. LOW-SULFUR FUELS 2-1
2.3.1. No. 4 Power Boiler 2-1
2.3.2. No. 5 Recovery Furnace 2-2
2.3.3. No. 6 Recovery Furnace 2-3
2.3.4. Fuel Cost Data 2-3
2.4. WET SCRUBBERS WITH CAUSTIC ADDITION 2-3
2.5. DRY SORBENT INJECTION (DSI) 2-4

3. FOUR FACTOR ANALYSES 3-1

3.1. COST OF COMPLIANCE 3-1
3.1.1. No. 4 Power Boiler 3-2
3.1.2. Nos. 5 and 6 Recovery Furnaces 3-2
*3.1.3. Use of Lower Sulfur Fuel Oil .... **Error! Bookmark not defined.***
3.2. TIME NECESSARY FOR COMPLIANCE 3-9
3.3. ENERGY AND NON-AIR QUALITY IMPACTS OF COMPLIANCE 3-9
3.4. REMAINING USEFUL LIFE 3-9

4. SUMMARY OF FINDINGS 4-1

APPENDIX A RBLC SUMMARY

APPENDIX B CONTROL COST ESTIMATES

1. EXECUTIVE SUMMARY

Brunswick Cellulose LLC owns and operates an integrated Kraft pulp mill (referred to as the "Brunswick Mill" or the "Mill") located in Brunswick, Glynn County, Georgia that manufacturers fluff pulp. The Brunswick Mill is a major source with respect to the Title V operating permit program and operates under a Title V Major Source Operating Permit (No. 2631-127-0003-V-06-0), issued by the Georgia Environmental Protection Division (Georgia EPD) with an effective date of January 1, 2016. The Brunswick Mill submitted a timely Title V renewal application on June 29, 2020, more than 6 months prior to expiration as required by the current Title V permit.

On July 10, 2020, Georgia EPD issued a letter to the Brunswick Mill requesting a Four Factor Analysis (FFA) for all significant sources of sulfur dioxide (SO_2) emissions at the site. For the purpose of this analysis, GP has defined a significant source as a source with greater than five tons of actual emissions of SO_2 averaged over the most recent three calendar years (2017 – 2019), which is the period selected to best represent 2028 emissions. Representative actual and potential-to-emit (PTE) emission rates for sources of SO_2 at the Mill are provided in Table 1-1 below.

Table 1-1 Source Summary

Unit ID	Name	PTE	3-Year Average SO_2 Emissions (tpy)	Fuels Fired	Controls
L537	No. 5 Lime Kiln	2.6	2.0	Natural Gas, No. 6 Fuel Oil	ESP and Scrubber
U700	No. 4 Power Boiler	568	149	Bark, No. 6 Fuel Oil, Natural Gas, Tire-Derived Fuel (TDF), Sludge	ESP
U706	No. 6 Power Boiler	1.1	0.1	Natural Gas, No. 2 Fuel Oil	None
U707	No. 7 Power Boiler	0.6	0.1	Natural Gas, No. 2 Fuel Oil	None
R401	No. 5 Recovery Furnace	520	121	Black Liquor Solids (BLS), No. 6 Fuel Oil, Natural Gas, Non-Condensable Gases (NCGs)	ESP
R403	No. 5 Smelt Dissolving Tank	2.4	2.0	N/A	Scrubber
R407	No. 6 Recovery Furnace	876	13.6	BLS, No. 2 Fuel Oil, Natural Gas, NCGs	ESP
R408	No. 6 Smelt Dissolving Tank	25.0	0.5	N/A	Scrubber
R480	Backup NCG Incinerator	39.9	0.1	Natural Gas	Scrubber

During the preparation of this summary, several inconsistencies were discovered in the reported emission rates for some of the emission units and the emission rates were updated for this analysis. These updates include:

- Inclusion of SO_2 emissions associated with BLS combustion in the reported emission rates for all three years for the No. 5 Recovery Furnace[1];
- Inclusion of SO_2 emissions from the No. 5 Smelt Dissolving Tank for all three years[2];
- Correction of a calculation error for 2017 and 2018 SO_2 emissions associated with natural gas combustion in the No. 6 Recovery Furnace;
- Correction of a calculation error in the 2019 SO_2 emission rate from the No. 4 Power Boiler; and
- Update of an outdated emission factor for SO_2 emissions from the No. 5 Lime Kiln, which resulted in lower emissions than were previously reported for all three years.

The three-year average emission rates in Table 1-1 reflect the updates made to address these inconsistencies. Based on the updated emission rates, the following emission units have been included in the FFA, as they are predicted to have more than five tons per year (tpy) of SO_2 emissions in 2028 based on the three-year actual emission rates:

- U700 – No. 4 Power Boiler,
- R401 – No. 5 Recovery Furnace, and
- R407 – No. 6 Recovery Furnace.

The FFA follows the August 20, 2019 EPA Guidance[3] to address regional haze further progress by reviewing:

- The cost of compliance,
- Energy and non-air quality impacts of compliance,
- The time necessary for compliance, and
- Remaining useful life of existing affected sources.

1.1. SOURCE INFORMATION

The sources to be evaluated consist of one boiler (U700) and two recovery furnaces (R401, R407).

The No. 4 Power Boiler (U700) fires carbonaceous fuel, consisting of wood materials such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; wastewater treatment system residuals; and tire-derived fuel (TDF). The boiler has a nominal capacity of 525,000 lbs/hr of steam. Particulate matter emissions are controlled by an electrostatic precipitator (ESP).

[1] These emissions were estimated using the median SO_2 emission factor for non-direct contact evaporator Kraft recovery furnaces from Table 4.12 of Technical Bulletin 1020 published by the National Council for Air and Stream Improvement (NCASI) (dated December 2013) and the actual BLS firing rate.
[2] These emissions were estimated using the median SO_2 emission factor for a smelt dissolving tank from Table 4.15 of NCASI Technical Bulletin 1020 (dated December 2013) and the actual BLS throughput.
[3] EPA-457/B-19-003, August 2019, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period."

The Mill's two recovery furnaces (R401 and R407) burn the organic material present in black liquor and reduce the inorganic compounds. The No. 5 Recovery Furnace is also equipped to fire natural gas, No. 6 fuel oil, and rectified methanol and the No. 6 Recovery Furnace is also equipped to fire natural gas, No. 2 fuel oil, and rectified methanol. In addition, the recovery furnaces are used as the primary combustion devices to thermally oxidize the low volume, high concentration (LVHC) and high volume, low concentration (HVLC) non-condensible gases (NCGs) from the pulping and recovery processes collected in the LVHC and HVLC collection systems. Particulate matter emissions from the recovery furnaces are controlled by dedicated ESPs.

1.2. REPORT CONTENTS

This FFA for the Brunswick Mill includes the following elements:

- Section 2 describes available control technologies,
- Section 3 provides the FFA for individual emission units,
- Section 4 provides a summary of findings,
- Appendix A contains a review of the RACT/BACT/LAER Clearinghouse (RBLC) for SO_2 controls, and
- Appendix B contains control cost data for individual units.

2. AVAILABLE SO_2 CONTROL TECHNOLOGIES

The following sections provide a brief description of potentially applicable control technologies for SO_2 control on the boiler and recovery furnaces.

2.1. CONTROL TECHNOLOGY OVERVIEW

EPA maintains a database of control technologies used at specific sources as part of control technology analyses for air permitting. The database was reviewed to determine available SO_2 controls for biomass combustion, fuel oil combustion, natural gas combustion[4], and recovery furnaces firing BLS over the past 20 years. Details on the RBLC review are provided in Appendix A. Available controls identified include the following:

- Good operating practices,
- Low-sulfur fuels,
- Wet scrubber with caustic addition, and
- Dry sorbent injection (DSI).

2.2. GOOD OPERATING PRACTICES

Good operating practices for an industrial boiler are important but are less likely to impact SO_2 emissions than other pollutants, such as nitrogen oxides (NO_x) and carbon monoxide (CO). For a recovery furnace, very low SO_2 emissions may be achieved from a well operated furnace. The primary purpose of a Kraft recovery furnace is to recover this sulfur and reuse it as fresh cooking chemical for the pulp. Most of the sulfur introduced to the recovery furnace leaves in the smelt. Factors that influence SO_2 emission rates include liquor sulfidity, liquor solids content, stack oxygen content, furnace load, auxiliary fuel use, and furnace design. The sodium salt fume in the upper furnace also acts to limit SO_2 emissions. The Nos. 5 and 6 Recovery Furnaces are both non-direct contact evaporator (NDCE) units, which typically have lower SO_2 emission than direct contact evaporator (DCE) units due to improved combustion efficiency.

2.3. LOW-SULFUR FUELS

2.3.1. No. 4 Power Boiler

The No. 4 Power Boiler fires carbonaceous fuel, consisting of wood materials, such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; wastewater treatment system sludge; and TDF. SO_2 emissions from natural gas combustion are not calculated for annual reporting because the emissions are expected to be minimal. Wastewater treatment sludge was not burned during the time period included in this analysis (2017 – 2019). Therefore, those fuels were not evaluated for replacement as part of this analysis.

Wood combustion in the No. 4 Power Boiler can result in SO_2 emissions that are similar in magnitude to the SO_2 emissions that result from the combustion of No. 6 fuel oil on a tons per year basis. However, this is because the total heat input from bark is much higher (10x to 100x

[4] Although there are entries in the RBLC for SO_2 from natural gas combustion, there are no add-on controls listed for these sources as natural gas is a low-sulfur fuel. For this reason, a list of the RBLC entries for natural gas is not included in the attachment.

the total heat input from fuel oil). GP does not believe that the replacement of wood fuel in this boiler with a lower sulfur fuel like natural gas or No. 2 fuel oil should be included for several reasons. The first is that the conversion of wood residuals generated at the site into energy and steam is the primary purpose of this boiler and wood is the primary fuel that the boiler was designed to combust. Changing the primary fuel from wood to natural gas or No. 2 fuel oil would represent a significant change to the operation of the boiler. The August 20, 2019 regional haze implementation guidance indicates that states may determine it is unreasonable to consider fuel use changes because they would be too fundamental to the operation and design of a source. In addition, EPA best available control technology (BACT) guidance states that it is not reasonable to change the design of a source, such as by requiring conversion of a coal boiler to a gas turbine.[5] The site would also have to find another way to dispose of the wood residuals that are currently burned in the boiler. The second reason is that the SO_2 emissions from bark combustion on a pounds per million British thermal units (lb/MMBtu) basis are relatively low (0.025 lb/MMBtu). Finally, if the No. 4 Power Boiler were converted to a natural gas boiler, the issues surrounding gas curtailments would be even more significant. The No. 4 Power Boiler is the primary steam generating power boiler at the site. The sudden loss of steam or reduction in steam production as a result of a natural gas curtailment would present a significant operational problem for the site. In spite of these concerns, a cost analysis has been included to evaluate the cost effectiveness of replacing bark with natural gas or No. 2 fuel oil[6].

The replacement of TDF with either natural gas or No. 2 fuel oil[6] has been included in the FFA for this boiler.

No. 6 fuel oil is a relatively high sulfur fuel. The No. 4 Power Boiler is capable of firing natural gas as an auxiliary fuel and from an operational perspective, most, if not all, of the No. 6 fuel oil firing over the three-year period used in the analysis for this boiler could be replaced with natural gas firing. This option is discussed further in the FFA for this emission unit. Switching to a lower sulfur blend of fuel oils or to No. 2 fuel oil[6] is also technically feasible and was therefore included in the FFA for this unit.

2.3.2. No. 5 Recovery Furnace

The No. 5 Recovery Furnace is equipped to fire natural gas, No. 6 fuel oil, and methanol recovered from the Methanol Rectifier system. Methanol and natural gas were not evaluated for replacement as part of this analysis.

No. 6 fuel oil is a relatively high sulfur fuel. Switching to a lower sulfur blend of fuel oils or to No. 2 fuel oil[7] is technically feasible and was therefore included in the FFA for this unit. The replacement of No. 6 fuel oil with natural gas was also evaluated. The No. 5 Recovery Furnace only uses natural gas to fire igniters while combusting either fuel oil or NCGs and is not currently

[5] https://www.epa.gov/sites/production/files/2015-07/documents/igccbact.pdf

[6] Please note that the No. 4 Power Boiler is not currently capable of firing No. 2 fuel oil but No. 2 fuel oil was included in the analysis because it is another low sulfur fuel option that is available at the site. Additional information is provided in Section 3.

[7] Please note that the No. 5 Recovery Furnace is not currently capable of firing No. 2 fuel oil but No. 2 fuel oil was included in the analysis because it is another low sulfur fuel option that is available at the site. Additional information is provided in Section 3.

capable of replacing the heat input supplied by fuel oil with natural gas. As noted above, the August 20, 2019 regional haze implementation guidance indicates that states may determine it is unreasonable to consider fuel use changes because they would be too fundamental to the operation and design of a source. In addition, EPA BACT guidance states that it is not reasonable to change the design of a source, such as by requiring conversion of a coal boiler to a gas turbine.[8] However, the replacement of No. 6 fuel oil combustion with natural gas combustion, which would require the installation of new auxiliary fuel burners, has been included in this analysis.

2.3.3. No. 6 Recovery Furnace

The No. 6 Recovery Furnace is equipped to fire natural gas, No. 2 fuel oil, and methanol recovered from the Methanol Rectifier system. Less than one ton per year of SO_2 emissions from natural gas or No. 2 fuel oil combustion were reported for any of the three years included in this analysis. Most of the SO_2 emissions from the furnace are associated with BLS firing or NCG combustion. Therefore, no fuel substitutions were included in the analysis for this emission unit.

2.3.4. Fuel Cost Data

The alternative fuels included in this analysis as replacements for No. 6 fuel oil (*i.e.*, natural gas and lower sulfur fuel oil) are generally more expensive than No. 6 fuel oil. Due to current economic uncertainty and fluctuations in fuel pricing, it is difficult to predict what the future cost of those fuel substitutions would be. For example, the delivered cost of No. 6 fuel oil has fluctuated between approximately $30 and $95 per barrel over the past year. The incremental price difference between No. 6 fuel oil and lower sulfur blended fuels has also varied by a factor of 10 times over the past several months. For this analysis, the average values for the delivered cost of No. 6 fuel oil, the delivered cost of No. 2 fuel oil, and the incremental additional cost for blended fuels have been used. The cost of natural gas has also fluctuated between approximately $13 and $35 per equivalent barrel. The annual average cost in 2019 was used for this analysis.

2.4. WET SCRUBBERS WITH CAUSTIC ADDITION

In wet scrubbing processes for gaseous control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may have a variety of different configurations, including plate or tray columns, spray chambers, and venturi scrubbers.

Wet scrubbers are considered technically feasible for both industrial boilers and recovery furnaces. However, the only two wet scrubbers used for SO_2 control in recovery furnaces listed in EPA's RBLC Database were not installed to meet a RACT/BACT/LAER requirement. Georgia-Pacific's Camas, Washington facility installed a wet scrubber on the Nos. 3 and No. 4 Recovery Furnaces (now shut down)

[8] https://www.epa.gov/sites/production/files/2015-07/documents/igccbact.pdf

for heat recovery purposes and not for SO_2 control. The other entry is for a MeadWestvaco facility in Wickliffe, Kentucky, which put in the scrubber to reduce SO_2 emissions to avoid triggering Prevention of Significant Deterioration (PSD) permitting.

2.5. DRY SORBENT INJECTION (DSI)

DSI accomplishes removal of acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream prior to particulate matter (PM) air pollution control equipment. A flue gas reaction takes place between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally "dry," meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and disposal of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and can be difficult to keep flowing. DSI systems are typically used to control SO_2, hydrochloric acid and other acid gas emissions from coal-fired boilers.

DSI is not technically feasible for recovery furnaces because dust from the recovery furnace flue gas is captured by the ESP and returned to the chemical recovery process. Introduction of the lime or trona into the flue gas will disrupt the recycle process and chemical balance. There are no known installations of DSI for recovery furnaces. DSI is technically feasible for industrial boilers.

3. FOUR FACTOR ANALYSES

The following sections evaluate the technically feasible control technologies for each source based on the four factors:

- The cost of compliance,
- The time necessary for compliance,
- Energy and non-air quality impacts of compliance, and
- Remaining useful life of existing affected sources.

The three emission units included in this evaluation are already utilizing good combustion practices. Therefore, this control strategy has not been evaluated further. As discussed in Section 2.3, the use of alternative fuels, such as natural gas or lower sulfur fuel oils, to replace higher sulfur fuels is a technically feasible option for the No. 4 Power Boiler and the No. 5 Recovery Furnace and has therefore been included in this analysis. Wet scrubbers with caustic addition were evaluated for all three emission units included in this analysis. As discussed in Section 2.5, DSI is not technically feasible for recovery furnaces and was therefore only evaluated for the No. 4 Power Boiler.

3.1. COST OF COMPLIANCE

For each source/control technology option that was analyzed, cost estimates were based on vendor data for similar sources and EPA guidance. Emissions used for cost per ton analyses were based on the average of the last three years as the Mill believes this is likely to best represent future (2028) operating conditions. The average actual emissions for the last three years were summarized in Table 1-1.

Although Georgia EPD has not indicated what additional controls they would consider cost effective, similar analyses performed by EPA and other states were reviewed to get a general idea of the level above which additional controls are not cost effective:

- Texas evaluated visibility impacts for controls with an estimated cost effectiveness of $5,000/ton or less,
- North Carolina has indicated a cost effectiveness threshold of less than $5,000/ton will be used to determine what controls are cost effective for Regional Haze,
- EPA has used a cost effectiveness threshold of less than $5,000/ton when determining if it is cost effective to require NO_x controls as part of regional transport rules,
- EPA did not further examine control options above $3,400/ton for the 2016 CSAPR update rule,
- EPA used $2,000/ton in the NO_x SIP call as the threshold for cost-effective controls,
- the Western Regional Air Partnership (WRAP) Annex to the Grand Canyon Visibility Transport Report (June 1999) indicated that control costs greater than $3,000/ton were high, and
- states such as New York and Pennsylvania consider NO_x controls less than approximately $5,000/ton as cost effective for Reasonably Available Control Technology (RACT).

For purposes of this analysis, GP believes that thresholds used by similar states of $5,000 per ton or less should be considered cost effective.

3.1.1. No. 4 Power Boiler

The No. 4 Power Boiler fires carbonaceous fuel, consisting of wood materials, such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; wastewater treatment system sludge; and TDF. Two control technologies were evaluated for SO_2 emissions control for the No. 4 Power Boiler – wet scrubbing and sorbent injection.

3.1.1.1. Wet Scrubber

GP obtained a cost estimate for a scrubber for a lime kiln at one of its Oregon facilities for a regional haze rule analysis earlier this year. [9] As this was the most recent quote for a similar unit available, the lime kiln scrubber cost estimate was used for the No. 4 Power Boiler by ratioing the exhaust gas flows to the 0.6 power. [10] Caustic use was based on the molar ratio of sodium hydroxide and SO_2 and an assumed 10% loss. Electricity requirements, water use, and waste generation rates were based on a detailed vendor quote for the No. 4 Power Boiler that was obtained for a Best Available Retrofit Technology (BART) analysis conducted in 2008. Facility costs for labor, electricity, caustic, and natural gas were based on the Brunswick Mill's site-specific data. Water and wastewater costs are based on data obtained for similar facilities. The capital costs were annualized based on a 30-year life span and a 5% interest rate as outlined in EPA's *DRAFT EPA SO_2 and Acid Gas Control Cost Manual.*[11]

Based on the cost information and emissions, a caustic scrubber would cost approximately $10,300 per ton of SO_2 removed, which is not cost effective.

3.1.1.2. Dry Sorbent Injection

The capital cost for a system to inject milled trona prior to a fabric filter was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[12] Facility labor, chemical, and utility costs were used to estimate the annual cost of operating the system. The Sargent and Lundy report indicates that 90% SO_2 control can be achieved when injecting trona prior to a fabric filter. The cost of the DSI system and operation alone is approximately $26,300 per ton of SO_2 removed, which is not cost effective. If DSI were installed on the No. 4 Power Boiler, a new baghouse would also have to be installed. As the costs of DSI alone were not cost effective, the additional cost of a baghouse was not included.

3.1.2. Nos. 5 and 6 Recovery Furnaces

In the Mill's two recovery furnaces (R401 and R407), the organic material present in black liquor is oxidized as the carbon is burned away and the inorganic compounds are smelted in reduction

---

[9] Although a lime kiln is very different from a power boiler, this estimate was determined to be conservative (lower than expected actual value) based on the design of the Brunswick boiler and the details of the lime kiln proposal.
[10] EPA, *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*, July 2020, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control.
[11] EPA, *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*, July 2020, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control.
[12] Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology*. Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

reactions. The molten inorganic chemicals, or smelt, consisting primarily of sodium carbonate (Na_2CO_3), collect in the bottom of the recovery furnaces, and pour out of spouts into the associated smelt dissolving tanks (R403 and R408). Salt cake, reclaimed from the economizer and the ESP (operated to control emissions of particulate matter), is mixed with black liquor and recycled back into the liquor system via black liquor/salt cake mix tanks and the precipitator mix tanks. The salt cake/black liquor mixture is either burned in the recovery furnaces or sent to a strong black liquor storage tank. The No. 5 Recovery Furnace is equipped to fire natural gas, No. 6 fuel oil, and methanol recovered from the Methanol Rectification System. The No. 6 Recovery Furnace is equipped to fire natural gas, No. 2 fuel oil, and methanol recovered from the Methanol Rectification System. In addition, the recovery furnaces are also used as a primary combustion device to thermally oxidize the LVHC and HVLC NCGs from the pulping and recovery processes collected in the LVHC and HVLC collection systems. Particulate matter emissions from the recovery furnaces are controlled by dedicated ESPs.

3.1.2.1. Wet Scrubber

As discussed above, a scrubber with caustic addition is the only technically feasible add-on SO_2 control option for recovery furnaces. For the recovery furnaces, GP utilized an American Forest and Paper Association (AF&PA) publication developed by BE&K Engineering, Emission Control Study – Technology Cost Estimates, September 2001.[13] Costs were scaled to 2019[14] dollars and then ratioed by the BLS throughputs to the 0.6 power. Caustic use was based on the molar ratio of sodium hydroxide and SO_2 and an assumed 10% loss. Electricity requirements, water use and waste generation costs were based on the AF&PA cost data and scaled based on permitted BLS throughput. Facility costs for labor and caustic were based on the Brunswick Mill's site-specific data. Water and wastewater costs are based on data obtained for similar facilities. The capital costs were annualized based on a 30-year life span and a 5% interest rate as outlined in EPA's *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*.[15]

Although the AF&PA costs are slightly dated, they were deemed to be the most representative as they were based on costs for a recovery furnace retrofit scrubber after an ESP. In addition, the costs are consistent with data presented in the November 2016 Washington Regional Haze plan[16] which estimates annual operating costs between $3 and 9 million per year. The costs in the Brunswick analysis were between $3.3 and 4.5 million per year.

Based on the cost information and emissions, a caustic scrubber would cost approximately $24,200 per ton of SO_2 removed for the No. 5 Recovery Furnace and $275,600 per ton of SO_2 removed for the No. 6 Recovery Furnace. These values are not considered cost effective.

[13] http://www.nescaum.org/documents/bart-resource-guide/be-k-capital-operating-cost-estimate-9-20-01.pdf/
[14] The most recent complete year of the Chemical Engineering Plant Cost Index (CEPCI) was used.
[15] EPA, *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*, July 2020, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control.
[16] Department of Ecology, *Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills*, November 2016 https://fortress.wa.gov/ecy/publications/SummaryPages/1602023.html

3.1.3. Lower Sulfur Fuels

Several fuel replacements were evaluated for the emission units included in this analysis to determine the cost effectiveness of replacing a higher sulfur fuel with a lower sulfur fuel. These replacements are discussed in detail below for each applicable emission unit.

3.1.3.1. No. 4 Power Boiler

The No. 4 Power Boiler fires carbonaceous fuel, consisting of wood materials, such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; wastewater treatment system sludge; and TDF. The primary fuel is wood, which has low SO_2 emissions. The SO_2 emissions calculated for all fuels included in this analysis are based on the consumption of that fuel and measured fuel properties over the three-year period used to represent 2028 emissions in this analysis (2017 – 2019)[17].

3.1.3.1.1. Replacement of Bark with Natural Gas

The No. 4 Power Boiler is equipped with natural gas burners that are permitted to supply 404 MMBtu/hr of heat input and are permitted to operate continuously (*i.e.,* 8,760 hours per year). The natural gas burners are currently operating below their permitted capacity and could accommodate additional natural gas firing in place of bark without exceeding current permit limits on natural gas firing. However, bark firing represents the primary heat input to the boiler and the existing natural gas burners may not be able to accommodate all of the additional fuel firing that would be required to replace bark firing with natural gas firing on a permanent basis. Therefore, replacement of the existing natural gas burners may be required. The costs associated with that replacement and any other necessary changes to the fuel system were not included in this analysis.

Based on current natural gas costs for the Brunswick Mill and the average heat input to the No. 4 Power Boiler from bark over the past three years, the cost to replace bark with natural gas in the boiler is approximately $262,600 per ton of SO_2 removed assuming no curtailment and approximately $385,500 using the higher curtailment price. Therefore, this fuel replacement is not cost effective.

3.1.3.1.1. Replacement of TDF with Natural Gas

As stated in the previous section, the natural gas burners are currently operating below their permitted capacity and could accommodate additional natural gas firing in place of TDF without exceeding current permit limits on natural gas firing.

Based on current natural gas costs for the Brunswick Mill, the average heat input to the No. 4 Power Boiler from TDF over the past three years, and the average cost of TDF for 2018 and 2019, the cost to replace TDF with natural gas in the boiler is negative, meaning that the Mill would save money by replacing TDF with natural

[17] These emission rates may differ from the SO_2 emission rates associated with No. 6 fuel oil combustion that have been previously reported to Georgia EPD for the No. 4 Power Boiler but are believed to be the most accurate estimate of emissions over those three years.

gas. The cost of natural gas that was used for this analysis may not be indicative of future costs and may not be indicative of the cost of natural gas at certain times of the year. The site can, and has been, subject to natural gas curtailments during colder months that result in higher natural gas costs. However, even if all additional natural gas were purchased at the higher curtailment price, the Mill would still save money by replacing TDF firing with natural gas firing in the No. 4 Power Boiler based on the data used in this analysis.

3.1.3.1.2. Replacement of TDF or Bark with No. 2 Fuel Oil

The No. 4 Power Boiler is not currently equipped to burn No. 2 fuel oil. However, a cost effectiveness analysis using only the fuel costs was performed to determine if further investigation of this fuel substitution was warranted.

Based on site data for No. 2 fuel oil costs and the average heat input to the No. 4 Power Boiler from bark over the past three years, the cost to replace bark with No. 2 fuel oil in the boiler is over $1MM per ton of SO_2 removed. Based on the average heat input to the boiler from TDF over the past three years, the cost to replace TDF with No. 2 fuel oil is approximately $13,600 per ton of SO_2 removed. Therefore, these fuel replacements are not cost effective based on fuel costs alone and the additional costs associated with burner updates and any other modifications required to fire No. 2 fuel oil in the No. 4 Power Boiler were not considered.

3.1.3.1.3. Replacement of No. 6 Fuel Oil with Natural Gas

The No. 4 Power Boiler is equipped with fuel oil burners that are capable of supplying 664 MMBtu/hr of heat input and natural gas burners that are permitted to supply 404 MMBtu/hr of heat input. Both sets of burners are permitted to operate continuously (*i.e.*, 8,760 hours per year). The natural gas burners are currently operating below their permitted capacity and could accommodate additional natural gas firing in place of No. 6 fuel oil without exceeding current permit limits on natural gas firing.

Based on current natural gas costs for the Brunswick Mill and the average heat input to the No. 4 Power Boiler from No. 6 fuel oil over the past three years, the cost to replace fuel oil with natural gas in the boiler is approximately $3,700 per ton of SO_2 removed. While this fuel replacement appears to be cost effective at this time, the cost of natural gas that was used for this analysis may not be indicative of future costs and may not be indicative of the cost of natural gas at certain times of the year. During colder months, the site can, and has been, subject to natural gas curtailments, which increase the purchase cost for gas by approximately $1.50 per MMBtu. If all additional natural gas were purchased at that higher price, the cost to replace No. 6 fuel oil firing with natural gas firing in the No. 4 Power Boiler would increase to approximately $5,500 per ton of SO_2 removed.

These estimates only account for the additional cost associated with purchasing additional natural gas and do not factor in the savings associated with reduced No. 6

fuel oil purchases. If the cost savings associated with the reduction in fuel oil purchases are included in the analysis, the cost effectiveness of replacing No. 6 fuel oil with natural gas is negative, meaning that the Mill would save money by switching from fuel oil to natural gas, even at the higher natural gas price associated with a curtailment. However, in addition to higher natural gas prices, the supply of natural gas may be inadequate during gas curtailments, which could lead to production curtailments and other operational impacts at the Mill. The flexibility to burn No. 6 fuel oil in the No. 4 Power Boiler as needed during gas curtailments ensures the stability of the steam supply and the stability of all other operations at the Mill that are dependent on steam supply.

3.1.3.1.4. Replacement of No. 6 Fuel Oil with Lower Sulfur Fuel Oil

This fuel replacement is discussed further in Section 3.1.3.3.

3.1.3.2. No. 5 Recovery Furnace

3.1.3.2.1. Replacement of No. 6 Fuel Oil with Natural Gas

The No. 5 Recovery Furnace is only equipped with natural gas igniters and does not currently have the capability to combust natural gas at the same heat input as No. 6 fuel oil. Therefore, to replace fuel oil with natural gas, new burners would be required. Because of the potential for natural gas curtailments, the burners would need to be of a dual fuel design to allow for future combustion of No. 6 fuel oil as needed for operational stability. The auxiliary fuel burners on the No. 6 Recovery Furnace were replaced with dual fuel burners in 2014. The cost of those replacements was used as the basis for the burner replacement cost estimate for the No. 5 Recovery Furnace. Costs were scaled to 2019[18] dollars and then ratioed by the required heat input to the 0.6 power. Although the dual fuel burners are not considered control equipment, the costs associated with the burner replacements were annualized using the method outlined in EPA's *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*. Based on this information, the cost to replace the existing fuel oil burners with dual fuel burners in the No. 5 Recovery Furnace is $3,600 per ton of SO_2 removed.

These estimates do not account for the additional cost associated with purchasing additional natural gas or the savings associated with reduced No. 6 fuel oil purchases. If the cost savings associated with the reduction in fuel oil purchases are included in the analysis, the cost effectiveness of replacing No. 6 fuel oil with natural gas is negative, meaning that the Mill would save money by switching from fuel oil to natural gas, even considering the cost of the new burners and the higher natural gas price associated with a curtailment. However, in addition to higher natural gas prices, the supply of natural gas may be inadequate during gas curtailments, which could lead to production curtailments and other operational impacts at the Mill. The flexibility to burn No. 6 fuel oil in the No. 5 Recovery Furnace as needed during gas

[18] The most recent complete year of the Chemical Engineering Plant Cost Index (CEPCI) was used.

curtailments ensures the stability of the steam supply and the liquor processing system and the stability of all other operations at the Mill that are dependent on steam supply and/or liquor availability.

3.1.3.2.2. Replacement of No. 6 Fuel Oil with Lower Sulfur Fuel Oil

This fuel replacement is discussed further in Section 3.1.3.3.

3.1.3.3. Use of Lower Sulfur Fuel Oil

The No. 4 Power Boiler and No. 5 Recovery Furnace fire No. 6 fuel oil, which is a relatively high sulfur fuel. The No. 5 Lime Kiln also fires No. 6 fuel oil. Actual SO_2 emissions from the No. 5 Lime Kiln are considered insignificant for the purpose of this analysis. However, the use of lower sulfur fuel in the No. 4 Power Boiler and No. 5 Recovery Furnace has the potential to impact the fuel fired in the No. 5 Lime Kiln since there is a single No. 6 fuel oil tank that supplies all three emission units. Therefore, either the fuel oil for all three emission units would need to be substituted with a lower sulfur fuel oil blend, or a new fuel oil tank would need to be constructed to supply the No. 4 Power Boiler and No. 5 Recovery Furnace separately from the No. 5 Lime Kiln. Both of these scenarios have been evaluated for cost effectiveness.

This analysis includes both the replacement of No. 6 fuel oil with a lower sulfur blended fuel and with No. 2 fuel oil. The lower sulfur blended fuel that would be used to replace the No. 6 fuel oil consists of a mixture of No. 6 and No. 2 fuel oils. Since the heat content of No. 2 fuel oil is lower than the heat content of No. 6 fuel oil and the cost of No. 2 fuel oil is higher, the blended fuel will have a lower heat content (*i.e.,* more fuel will be needed to meet current heat input requirements) and will be more expensive. Therefore, the cost to switch to the lower sulfur blended fuel includes the incremental additional cost for the blended fuel and the total cost of the additional fuel that would need to be purchased to meet heat input requirements.

The analysis of blended fuels includes fuel blends with 1.5% sulfur and 1% sulfur. Based on data provided by the fuel vendor, the properties of blended fuel (*e.g.,* viscosity) can change drastically as more No. 2 fuel oil is blended into the No. 6 fuel oil to reduce sulfur content. Burning either of the blends considered in this cost analysis would require some minor modifications to the combustion system of the units firing the blended fuel. As the sulfur content drops below 1%, the corresponding changes to fuel properties could create operational issues without more extensive modifications to the fuel oil burners and pumping system. Therefore, the capital costs included in the cost effectiveness calculations for firing No. 2 fuel oil are different from the capital costs included for the blended fuels.

Both of the scenarios described below include the approximate cost of the equipment modifications required to burn the fuel oil that is being evaluated. Although these equipment modifications are not considered control equipment, the costs associated with the modifications were annualized using the method outlined in EPA's *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*.

3.1.3.3.1. Scenario 1 – Replacement of No. 6 Fuel Oil in All Three Emission Units

In the first scenario described above, which involves switching all three emission units that currently fire No. 6 fuel oil to the lower sulfur blended fuel, the cost to replace No. 6 fuel oil with a lower sulfur blended fuel is approximately $14,500 per ton of SO_2 removed for a 1.5% sulfur blend and $3,800 per ton of SO_2 removed for a 1% sulfur blend. The cost to replace No. 6 fuel oil with No. 2 fuel oil is approximately $6,500 per ton of SO_2 removed.

Data collected by the National Council for Air and Stream Improvement, Inc. (NCASI) on lime kilns that fire either fuel oil or natural gas and are equipped with a scrubber indicate that SO_2 emissions tend to be low regardless of the type of fuel fired in the kiln. The lime burned in the kiln can act as a scrubbing agent inside the kiln itself and the presence of a wet scrubber can enhance SO_2 removal since the scrubbing solution may become alkaline as lime dust is captured. The SO_2 emission rate for the No. 5 Lime Kiln included in the control cost analysis is based on a NCASI emission factor for a lime kiln that fires either fuel oil or natural gas and is not dependent on the fuel being fired. Therefore, the SO_2 emissions from the No. 5 Lime Kiln are not expected to change as a result of changes in the sulfur content of the fuel oil fired in the unit. Additional detail is provided in the calculations for this scenario in Appendix B.

3.1.3.3.2. Scenario 2 – Replacement of No. 6 Fuel Oil in the No. 4 Power Boiler and the No. 5 Recovery Furnace and Construction of a New Fuel Oil Tank

In the second scenario discussed above, which involves switching only the No. 4 Power Boiler and the No. 5 Recovery Furnace to a lower sulfur blended fuel and the construction of a new fuel oil tank, the cost to replace No. 6 fuel oil with a lower sulfur blended fuel is approximately $16,200 per ton of SO_2 removed for a 1.5% sulfur blend and $3,700 per ton of SO_2 removed for a 1% sulfur blend. The cost to replace No. 6 fuel oil with No. 2 fuel oil is approximately $4,950 per ton of SO_2 removed.

These costs include the cost to construct a new 500,000-gallon fuel oil tank that would supply the No. 4 Power Boiler and No. 5 Recovery Furnace. The cost estimate for this tank is based on the approximate cost to install a similarly sized carbon steel tank at another Koch Industries company site in Texas. The total cost includes an approximate cost for the tank foundation and external coating, but does not include other components that may be necessary, such as spill containment or additional piping. Although this tank is not a control device, the methods outlined in EPA's *DRAFT EPA SO_2 and Acid Gas Control Cost Manual* were used to determine the annual costs associated with the construction and use of the tank. Those annual costs were added to the fuel costs to determine the cost per ton of SO_2 removed for each fuel[19].

3.2. TIME NECESSARY FOR COMPLIANCE

EPA allows three years plus an optional extra year for compliance with Maximum Achievable Control Technology (MACT) standards that require facilities to install controls after the effective date of the final standard. Although our FFA shows there are no additional add-on controls that would be feasible, if controls or other construction projects, such as the installation of a new fuel oil tank or new burners, are ultimately required to meet Regional Haze Rule (RHR) requirements, facilities would need at least four to five years to implement these changes after final EPA approval of the RHR State Implementation Plan (SIP). The Mill would need time to obtain corporate approvals for capital funding. The facility would have to undergo substantial re-engineering due to space constraints and other issues to accommodate new controls. Design, procurement, installation, and shakedown of these projects would easily consume three years. The facility would need to engage engineering consultants, equipment vendors, construction contractors, and other critical suppliers. Lead time would be needed to procure pollution control equipment even after it is designed and a contract is finalized, and installation of controls must be aligned with Mill outage schedules that are difficult to move. The facility would need to continue to operate as much as possible while retrofitting to meet any new requirements.

Construction would need to be staggered so only one unit was out of service at a time. Staggering work on separate units at the same facility allows some level of continued operation. However, this staggering extends the overall compliance time. Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been lined up (*e.g.*, the engineering is complete and the control equipment is staged for immediate installation), can an owner afford to shut down a facility's equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers. The process to undertake a retrofitting project is complex.

3.3. ENERGY AND NON-AIR QUALITY IMPACTS OF COMPLIANCE

Use of an SO_2 scrubber requires the use of additional water and generates a wastewater stream that must be treated. Additional electricity is required to power scrubber fans. Dry sorbent injection results in additional waste being generated.

3.4. REMAINING USEFUL LIFE

The emissions units included in this FFA are assumed to have a remaining useful life of thirty years or more.

[19] The tank cost was also included in the cost effectiveness calculations for firing No. 2 fuel oil in the No. 4 Power Boiler and No. 5 Recovery Furnace. While No. 2 fuel oil is currently stored at the site for use in the No. 6 Recovery Furnace and other emission units, the existing storage capacity is not adequate to supply No. 2 fuel oil to the No. 4 Power Boiler and the No. 5 Recovery Furnace.

4. SUMMARY OF FINDINGS

The Brunswick Mill analyzed the significant SO_2 emissions sources for additional control utilizing EPA's four factor method. No add-on controls are deemed feasible or cost-effective. However, some fuel replacements may be cost-effective. Based on the information included in this analysis, GP proposes to eliminate TDF firing in the No. 4 Power Boiler, which will result in a reduction of approximately 67 tpy[20] of SO_2 emissions from the site. Discontinuing the use of TDF as an auxiliary fuel appears to be cost effective based on the fuel costs used in this analysis and would not require modifications to any equipment at the site, eliminating any considerations related to the time necessary for compliance.

[20] Based on the calculated average SO_2 emissions associated with TDF combustion over the three-year period included in this analysis (2017-2019).

APPENDIX A

RBLC SEARCH RESULTS

RBLC Entries for SO2, Oil Fired Boilers

Facility Name	ST	Process Name	Primary Fuel	Throughput	Unit	Control Method Description	Emission Limit 1	Unit	Time Condition	Emission Limit 2	Unit	Time Condition
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	RECOVERY BOILER	NO. 6 FUEL OIL	557.00	MMBTU/H	GOOD COMBUSTION PRACTICE	979	LB/H		n/a		
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	SMELT TANKS				FAN IMPINGEMENT-TYPE WET SCRUBBER	6	LB/H		n/a		
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	BOILER, POWER, COAL-FIRED	COAL	249	MMBTU/H	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	1	LB/MMBTU		n/a		
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	BOILER, POWER, OIL-FIRED	NO. 6 FUEL OIL	249.0	MMBTU/H	MULTICLONE AND VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	1	LB/MMBTU		n/a		
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	BOILER, POWER, WOODWASTE-FIRED	WOODWASTE	600.0	MMBTU/H	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	0.0	LB/MMBTU		n/a		
MILLER BREWING COMPANY -Trenton	OH	BOILER (2), NO. 6 FUEL OIL	NO. 6 FUEL OIL	238	MMBTU/H		1.60	LB/MMBTU		2,758	T/YR	BOTH BOILERS TOGETHER, PER ROLLING 12-MO
MILLER BREWING COMPANY	OH	BOILER (2), NATURAL GAS	NATURAL GAS	238	MMBTU/H		2	LB/MMBTU		2,758	T/YR	BOTH BOILERS TOGETHER, PER ROLLING 12-MO
MILLER BREWING COMPANY	OH	BOILER (2), COAL FIRED	COAL	238.00	MMBTU/H		1.60	LB/MMBTU		2,758	T/YR	BOTH BOILERS TOGETHER, PER ROLLING 12-MO
MILLER BREWING COMPANY	OH	BOILER (2), NO. 2 FUEL OIL	NO. 2 FUEL OIL	238.00	MMBTU/H		1.60	LB/MMBTU		2,758	T/YR	BOTH BOILERS TOGETHER, PER ROLLING 12-MO
VIRGINIA COMMONWEALTH UNIVERSITY	VA	BOILER - NO 6 FUEL OIL	FUEL OIL #6	150.0	MMBTU/H	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	79	LB/H	each unit 3hr rolling avg	n/a		
VIRGINIA COMMONWEALTH UNIVERSITY	VA	BOILER NATUAL GAS	NATURAL GAS	150.0	MMBTU/H	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	0.1	LB/H	each unit 3hr rolling avg	n/a		
VIRGINIA COMMONWEALTH UNIVERSITY	VA	BOILER - DISTILLATE	FUEL OIL #2	150.0	MMBTU	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	78.50	LB/H	each unit 3hr rolling avg	n/a		
VIRGINIA COMMONWEALTH UNIVERSITY	VA	BOILER - OIL OR GAS	GAS OR OIL	150.0	MMBTU	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	196.30	T/YR	combined units	n/a		
Virginia Commonwealth University	VA	BOILER, NATURAL GAS, (3)	NATURAL GAS	150.6	MMBTU/H	LOW SULFUR FUEL	0.10	LB/H		n/a		
Virginia Commonwealth University	VA	BOILER, #6 FUEL OIL, (3)	# 6 FUEL OIL	150.6	MMBTU/H	FUEL SULFUR LIMIT: < 0.5% S BY WT	78.50	LB/H		196.3	T/YR	combined operation, all fuels
Virginia Commonwealth University	VA	BOILER, #2 FUEL OIL, (3)	NO. 2 FUEL OIL	151	MMBTU/H	FUEL SULFUR LIMITS: <0.5% S BY WT.	79	LB/H		n/a		
HERCULES INC	VA	CHEMICAL PREP	NATURAL GAS	90.0	MMBTU/H	CEMS AND GOOD COMBUSTION PRACTICES	0	LB/H		n/a	LB/H	
HERCULES INC	VA	CHEMICAL PREP	DISTILLATE OIL	90	MMBTU	WET OR DRY SCRUBBER AND GOOD COMBUSTION PRACTICES	9	LB/H		9	LB/H	
HERCULES INC	VA	CHEMICAL PREP	RESIDUAL OIL	90	MMBTU	0.5% S AND WET OR DRY SCRUBBER. GOOD COMBUSTION PRACTICES	9.5	LB/H		10	LB/H	
HERCULES INC	VA	CHEMICAL PREP	DISTILLATE OIL	90	MMBTU	.5% S FUEL AND GOOD COMBUSTION PRACTICES	45.40	LB/H		45.40	LB/H	
WEIDMANN ELECTRICAL TECHNOLOGY, INC.	VT	WEST BUILDING BOILER #3	NO.6 FUEL OIL	19.4	MMBTU/H HEAT INPUT	LOW SULFUR FUEL	0.50	% SULFUR CONTENT		n/a		
MIDDLEBURY COLLEGE	VT	Boiler #12	No. 6 fuel oil	57	MMBTU/H	Use of 0.5% (max) sulfur content fuel oil	1	% SULFUR CONTENT		n/a		

RBLC Entries for SO2, Wood Fired Boilers

FACILITY_NAME	ST	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	CONTROL_METHOD_DESCRIPTION	EMISSION LIMIT 1	UNIT	TIME CONDITION	EMISSION LIMIT 2	UNIT	TIME CONDITION
CLEWISTON MILL	FL	Boiler No. 9	Bagasse	1077	MMBtu/hr	Inherently low-sulfur fuels and natural alkalinity of bagasse can scrub out sulfur emissions.	0.064	LB/MMBTU	--		--	--
HIGHLANDS ENVIROFUELS	FL	Cogeneration Biomass Boiler	Bagasse	458	MMBtu/hr	--	0.06	LB/MMBTU	30-DAY-ROLLING	0.078	LB/MMBTU	1-HR AVG
WARREN COUNTY BIOMASS ENERGY FACILITY	GA	Boiler, Biomass Wood	Biomass wood	100	MW	Dust sorbent injection system	0.01	LB/MMBTU	30 D ROLLING AV / CONDITION 2.12	56	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.20
ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) system	0.21	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	110.25	LB/HR	MAX 1-HR, INCLUDES SS, EXCLUDES MALFUNCT
RED RIVER MILL	LA	NO. 2 HOGGED FUEL BOILER	HOGGED FUEL/BARK	992.43	MMBTU/H	Use of low sulfur fuels	60	LB/H	HOURLY MAXIMUM	262.8	T/YR	ANNUAL MAXIMUM
VERSO BUCKSPORT LLC	ME	Biomass Boiler 8	Biomass	814	MMBTU/H	0.7% sulfur when firing oil	0.8	LB/MMBTU	3-HR AVERAGE	651.2	LB/H	--
BERLIN BIOPOWER	NH	EU01 BOILER #1	WOOD	1013	MMBTU/H	Wood Fuel	0.012	LB/MMBTU	STACK TEST		--	--
GP CLARENDON LP	SC	334 MILLION BTU/HR WOOD FIRED FURNACE #2	WOOD	334	MMBTU/H	SO2 Emissions controlled through good combustion practices	28.14	LB/H	--	117.1	T/YR	--
GP CLARENDON LP	SC	197 MILLION BTU/HR WOOD FIRED FURNACE	WOOD	197	MMBTU/H	SO2 Emissions controlled through good combustion practices	28.14	LB/H	--	117.1	T/YR	--
GP CLARENDON LP	SC	334 MILLION BTU/HR WOOD FIRED FURNACE #1	WOOD	334	MMBTU/H	SO2 Emissions controlled through good operating practices	28.14	LB/H	--	117.1	T/YR	--
LINDALE RENEWABLE ENERGY	TX	Wood fired boiler	biomass	73	T/H	--	0.025	LB/MMBTU	ROLLING 30- DAY AVG		--	--
LUFKIN GENERATING PLANT	TX	Wood-fired Boiler	wood	693	MMBtu/H	--	0.025	LB/MMBTU	30 DAY ROLLING AVERAGE		--	--
BEAVER WOOD ENERGY FAIR HAVEN	VT	Main Boiler	wood	482	MMBTU/H	Use of low sulfur fuel (wood)	0.02	LB/MMBTU	HOURLY AVERAGE		--	--
NORTH SPRINGFIELD SUSTAINABLE ENERGY PROJECT	VT	Wood Fired Boiler	wood	464	MMBTU/H	Use of low sulfur fuel (wood)	0.02	LB/MMBTU	HOURLY AVERAGE	10	LB/H	HOURLY AVERAGE

RBLC Entries for SO2, Recovery Furnaces

Facility Name	ST	Process Name	Primary Fuel	Throughput	Unit	Control Method Description	Emission Limit 1	Unit	Time Condition	Emission Limit 2	Unit	Time Condition
ROCK-TENN MILL COMPANY, LLC	AL	RECOVERY FURNACE	--	4.32	mmlb/day	--	100	PPMV @ 8% O2	3 HR	252.9	LB/H	3 HR
ID COURTLAND	AL	NO. 3 RECOVERY FURNACE	BLACK LIQUOR	950	MMBTU/H	--	75	PPM@8% O 2	3HRS	31	PPM@8% O 2	3HRS
BOWATER INC. COOSA PINES OPERATIONS	AL	NO. 3 RECOVERY FURNACE	BLACK LIQUOR	816	MMBTU/H	--	75	PPM@8% O2	3HRS AVG	169.6	LB/H	3HRS
ALABAMA RIVER PULP	AL	RECOVERY FURNACE	BLACK LIQUOR	7.5	MMLB BLS/DAY	--	60	PPMDV		271	LB/H	
GEORGIA-PACIFIC CORPORATION - CROSSETT PAPER OPERATIONS	AR	8R RECOVERY BOILER	BLACK LIQUOR SOLIDS AND NO. 6 FUEL OIL	6.9	MMLB BLS/D	COMBUSTION CONTROL	84.7	LB/H	BLS WITH SUPPLEMENTAL OIL, 3-HR AV	989.1	LB/H	SPEC OIL ONLY, 3-HR AV
MEADWESTVACO KENTUCKY, INC/WICKLIFFE	KY	RECOVERY FURNACE	--	473000	LB/H	WET SCRUBBER	0.29	LB/T ADP	--		--	--
MANSFIELD MILL	LA	RECOVERY BOILER NO.1 AND NO.2	--	71	TBLS/H	GOOD PROCESS CONTROLS	510	LB/H	--	2233.8	T/YR	--
PORT HUDSON OPERATIONS	LA	RECOVERY FURNACE NO. 1	--	2.81	MM LB/D	--	105.91	LB/H	--	463.88	T/YR	--
PORT HUDSON OPERATIONS	LA	RECOVERY FURNACE NO. 2	--	3.96	MM LB/D	--	143.23	LB/H	--	627.35	T/YR	--
RED RIVER MILL	LA	RECOVERY BOILER NO. 3	BLACK LIQUOR	6.4	MM LB/D	PROPER BOILER DESIGN AND OPERATION	20	PPM @ 8% O2*	--		--	--
MANSFIELD MILL	LA	RECOVERY BOILERS NO. 1 &2	--	961.3	MMBTU/H	PROPER DESIGN, GOOD COMBUSTION PRACTICES, FIRING LOW SULFUR FUEL, AND A 10% ANNUAL	217.6	LB/H	HOURLY MAXIMUM	907.9	T/YR	ANNUAL MAXIMUM
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	RECOVERY BOILER NO. 1	BLACK LIQUOR	861.4	MMBTU/H	--	408.33	LB/H	--	1788.5	T/YR	--
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	RECOVERY BOILER NO. 2	BLACK LIQUOR	861.4	MMBTU/H	--	408.33	LB/H	--	1788.5	T/YR	--
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	BOILER, NO. 1 RECOVERY	BLS	861.4	MMBTU/H	COMBUSTION CONTROL AND FURNACE DESIGN	408.33	LB/H	--	1788.5	T/YR	--
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	BOILER, NO. 2 RECOVERY	BLS	861.4	MMBTU/H	COMBUSTION CONTROL AND FURNACE DESIGN	408.33	LB/H	--	1788.5	T/YR	--
INTERNATIONAL PAPER - ROANOKE RAPIDS MILL	NC	NO. 7 RECOVERY FURNACE	BLACK LIQUOR SOLIDS	3	MMLB/D	FURNACE DESIGN AND COMBUSTION OPTIMIZATION	75	PPM	8% O2 ANNUAL	110	PPM	8% O2 3-HOUR
WEYERHEAUSER COMPANY-MARLBORO PAPER MILL	SC	NO. 1 RECOVERY FURNACE	HEAVY BLACK LIQUOR	4.4	MMLB/D	GOOD COMBUSTION/RECOVERY FURNACE FIRING RATE AND	75	PPM @ 8% O2	--	838	T/YR	--
RESOLUTE FP US INC	SC	NO. 3 RECOVERY FUNRACE	BLACK LIQUOR	2040	T/D BLS	FUEL MONITORING (USE AND SULFUR CONTENT)	50	PPM (DRY BASIS)	--	551	T/YR	12 MONTH ROLLING SUM
INLAND PAPERBOARD AND PACKAGING ORANGE MILL	TX	NO.1 AND NO. 2 RECOVERY FURNACE	NATURAL GAS	--	--	--	915.7	LB/H	--	1372	T/YR	--
INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	TX	NO 2 RECOVERY FURNACE EAST/WEST STACK	--	--	--	--	375.71	LB/H	--	521.11	T/YR	--
INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	TX	NO 1 RECOVERY FURNACE NORTH/SOUTH STACK	--	--	--	--	210.94	LB/H	--	307.98	T/YR	--
LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	RECOVERY FURNACE 15	--	1150	TBLS/D	--	60	PPMDV @ 8% O2	3 H AV	365	T/YR	--
LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	RECOVERY FURNACE 18	--	1200	TBLS/D	FACILITY WILL HAVE A FEDERAL LIMIT OF SO2 REPRESENTING A 53% REDUCTION FROM THE	60	PPMDV @ 8% O2	3 H AV	202	T/YR	--
LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	RECOVERY FURNACE 19	--	2000	T BLS/D	FACILITY WILL HAVE A LIMIT ON SO2 REPRESENTING A	60	PPMDV @ 8% O2	3 H AV	301	T/YR	MO AV
LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	RECOVERY FURNACE 22	--	1950	T BLS/D	--	120	PPMDV @ 8% O2	3 H AV	1291	T/YR	
JAMES RIVER CORP (now GP)	WA	RECOVERY FURANCE #4	BLACK LIQUOR	770	MMBTU/H	HEAT RECOVERY SCRUBBER	10	PPM		46	T/YR	
MOSINEE PAPER CORPORATION	WI	RECOVERY BOILER, PROCESS #B21, STACK #S11	BLACK LIQUOR	250	MMBTU/H	--	209.8	T/YR	--		--	--
DOMTAR NEKOOSA MILL	WI	KRAFT BLACK LIQUOR RECOVERY FURNACE, B14	STRONG BLACK LIQUOR	37.5	bl	GOOD OPERATING PRACTICES	60	PPMDV @ 8% O2	--		--	--

APPENDIX B

CONTROL COST ANALYSES

Capital & Operating Cost Evaluation for SO_2 Scrubber for the No. 4 Power Boiler

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$2,400,000	Based on 2020 cost estimate for Lime Kiln for similar 4-factor Analysis
Vendor Quoted System (cfm) =	41,500	
CFM analyzed =	412,411	
Engineering Factor =	1.0	Vendor quote includes auxiliary costs.
Total Capital Investment (TCI)	**$9,518,762**	Prorated from previous vendor quote based on capacity ratio raised to the power of 0.6
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0527	CRF = 3.25% interest (current bank prime rate as of 9/27/2021) and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$501,465***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$18,089	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,713	B = 15% of operating labor
Maintenance Labor	$20,860	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$20,860	D = Equivalent to maintenance labor
Caustic Costs	$166,382	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in 1.3.4 of July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	734	Power (kWh), base on a site-specific analysis from 2008.
Cost of Electricity Usage	$291,810	F = E × Electricity Cost
Fresh Water	$80,170	G = Freshwater use * water cost
Water Disposal	$26,708	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$627,592***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$37,513	H = 60% × (A + B + C + D)
Insurance	$95,188	J = 1% × TCI
Administrative Charges	$190,375	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$323,076***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$1,452,133**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	143	
SO_2 Removed (tpy)	141	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$10,330**	**$/ton = AC / Pollutant Removed**

1. TCI per 2020 Envitech estimate for a Lime Kiln scrubber at another GP facility.
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

Brunswick No. 4 Power Boiler

Capital and Annual Costs Associated with Trona Injection

Variable	Designation	Units	Value	Calculation
Heat Input		MMBtu/hr	422.9	3-year average actual
Unit Size	A	MW	37	Based on 3-year average actual, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	37,944	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.082	3-year average actual
Type of Coal	E	-		
Particulate Capture	F	-	Fabric filter	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	90	Per the Sargent and Lundy document, 90% reduction can be achieved using milled trona with a fabric filter.
Heat Input	J	Btu/hr	4.23E+08	
NSR	K	-	2.61	Milled Trona w/ FF = 0.208e^(0.0281*H)
Sorbent Feed Rate	M	ton/hr	0.36	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	98.85	Milled or Unmilled Trona w/ FF = 84.598*H^0.0346
Sorbent Waste Rate	N	ton/hr	0.29	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	3.84	Ash in Bark and TDF = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.19	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0.045	Site-specific power cost
Operating Labor Rate	U	$/hr	52.86	Typical labor cost, includes 60% overhead cost

SO_2 Control Efficiency:	90%
Representative Emissions	143.4
Controlled SO_2 Emissions:	129.1

Capital Costs					
Direct Costs					
BM (Base Module) scaled to 2019 dollars		$	$	6,965,755	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	696,575	10% BM
Labor adjustment	A2	$	$	348,288	5% BM
Contractor profit and fees	A3	$	$	348,288	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	8,358,906	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	417,945	5% CEC
Total project cost w/out AFUDC	TPC	$	$	8,776,851	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$**	**8,776,851**	CECC+B1+B2

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	219,914	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	69,658	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	7,433	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**297,005**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	536,602	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	1,807,420	(N+P)*S
Additional auxiliary power required	VOMP	$	$	28,655	Q*T*10*A
Total Variable O&M Cost	**VOM**	**$**	**$**	**2,372,677**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	175,537	
Insurance	1%	of TCI	$	87,769	
Capital Recovery	5.27%	x TCI	$	462,380	
Total Indirect Annual Costs			**$**	**725,685**	
Life of the Control:		30 years		3.25%	current bank prime rate as of 9/27/2021
Total Annual Costs			**$**	**3,395,367**	
Total Annual Costs/SO_2 Emissions			**$**	**26,301**	

[a]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system. 2016 costs scaled to 2019 costs using the CEPCI.

Capital & Operating Cost Evaluation for SO_2 Scrubber for the No. 5 Recovery Furnace

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$19,788,754	AFPA 2001 Data, scaled to 2019 dollars based on CEPCI of 394.3 (2001) and 607.5 (2019)
Vendor Quoted System BLS (ton BLS/day) =	1,850	AFPA 2001 Data
BLS Analyzed (ton BLS/day) =	2,160	
Engineering Factor =	1.0	Vendor quote includes auxiliary costs.
Total Capital Investment (TCI)	**$21,716,392**	Prorated from previous vendor quote based on capacity ratio raised to the power of 0.6
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0527	CRF = 3.25% interest (current bank prime rate as of 9/27/2021) and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$1,144,057***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$18,089	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,713	B = 15% of operating labor
Maintenance Labor	$20,860	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$20,860	D = Equivalent to maintenance labor
Caustic Costs	$140,359	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in 1.3.4 of July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	1,905 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$757,376	F = E × Electricity Cost
Fresh Water	$74,403	G = Freshwater use * water cost
Water Disposal	$7,027	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$1,041,688***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$37,513	H = 60% × (A + B + C + D)
Insurance	$217,164	J = 1% × TCI
Administrative Charges	$434,328	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$689,005***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$2,874,749**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	121	
SO_2 Removed (tpy)	119	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$24,242**	**$/ton = AC / Pollutant Removed**

1. TCI Per AFPA BE & K Study, 2001 ratioed to 2019 dollars.
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

Capital & Operating Cost Evaluation for SO_2 Scrubber for the No. 6 Recovery Furnace

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$19,788,754	AFPA 2001 Data, scaled to 2019 dollars based on CEPCI of 394.3 (2001) and 607.5 (2019)
Vendor Quoted System BLS (ton BLS/day) =	1,850	AFPA 2001 Data
BLS Analyzed (ton BLS/day) =	3,240	
Engineering Factor =	1.0	Vendor quote includes auxiliary costs.
Total Capital Investment (TCI)	**$27,697,618**	Prorated from previous vendor quote based on capacity ratio raised to the power of 0.6
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0527	CRF = 3.25% interest (current bank prime rate as of 9/27/2021) and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$1,459,158***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$18,089	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,713	B = 15% of operating labor
Maintenance Labor	$20,860	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$20,860	D = Equivalent to maintenance labor
Caustic Costs	$15,735	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in 1.3.4 of July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	2,857 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$1,136,064	F = E × Electricity Cost
Fresh Water	$111,605	G = Freshwater use * water cost
Water Disposal	$10,540	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$1,336,467***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$37,513	H = 60% × (A + B + C + D)
Insurance	$276,976	J = 1% × TCI
Administrative Charges	$553,952	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$868,442***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$3,664,067**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	14	
SO_2 Removed (tpy)	13	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$275,621**	**$/ton = AC / Pollutant Removed**

1. TCI Per AFPA BE & K Study, 2001 ratioed to 2019 dollars.
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

Cost Evaluation for the Replacement of Bark with Natural Gas or No. 2 Fuel Oil in the No. 4 Power Boiler

			Natural Gas									No. 2 Fuel Oil					
						Using 2019 Average Price			Including Additional Curtailment Cost						Using Average Price		
Bark Firing (tons)	Heat Input from Bark (MMBtu)	SO_2 Emissions from Bark Combustion (tpy)	Natural Gas Heating Value (MMBtu/MMscf)	Natural Gas Required to Replace Bark (MMscf)	SO_2 Emissions from Natural Gas Combustion to Replace Bark (tpy)	Cost of Natural Gas ($/MMscf)	Cost to Purchase Replacement Natural Gas ($)	Cost per ton ($/ton)	Cost of Natural Gas ($/MMscf)	Cost to Purchase Replacement Natural Gas ($)	Cost per ton ($/ton)	No. 2 Fuel Oil Heating Value (Btu/gal)	No. 2 Fuel Oil Required to Replace Bark (Mgal)	SO_2 Emissions from No. 2 Fuel Oil Combustion to Replace Bark (tpy)	Cost of No. 2 Fuel Oil ($/bbl)	Cost to Purchase Replacement No. 2 Fuel Oil ($)	Cost per ton ($/ton)
286,959	2,210,399	28	1,031	2,144	0.64	$3,306	$7,088,019	$262,648	$4,852	$10,404,004	$385,523	138,000	16,017	1.71	$77	$29,411,925	$1,134,538

1. Fuel oil consumption, SO_2 emissions from fuel oil, and natural gas heating value are based on the most recent 3 calendar years of data (2017 - 2019).
2. SO_2 emissions from natural gas combustion are based on the SO_2 emission factor from AP-42, Section 1.4, Table 1.4-2 (0.6 lb/MMscf).
3. The natural gas required to replace No. 6 fuel oil is calculated as follows:
   Natural Gas Required to Replace Bark (MMMscf) = Heat Input from Bark (MMBtu) / Heat Content of Natural Gas (Btu/scf)
4. Cost data provided by the fuel vendor.

Emission Factor for No. 2 Fuel Oil	142 S	lb/Mgal, Table 1.3-1 of AP-42
Sulfur Content of No. 2 Fuel Oil	0.0015	%S for ULSD
No. 2 Fuel Oil Cost	77.12	$/bbl, average value

Cost Evaluation for the Replacement of TDF with Natural Gas or No. 2 Fuel Oil in the No. 4 Power Boiler

				Natural Gas									No. 2 Fuel Oil					
							Using 2019 Average Price			Including Additional Curtailment Cost						Using Average Price		
TDF Firing Usage (tons)	Heat Input from TDF (MMBtu)	SO_2 Emissions from TDF Combustion (tpy)	Cost of TDF ($)	Natural Gas Heating Value (MMBtu/MMscf)	Natural Gas Required to Replace TDF (MMscf)	SO_2 Emissions from Natural Gas Combustion to Replace TDF (tpy)	Cost of Natural Gas ($/MMscf)	Cost to Purchase Replacement Natural Gas ($)	Cost per ton ($/ton)	Cost of Natural Gas ($/MMscf)	Cost to Purchase Replacement Natural Gas ($)	Cost per ton ($/ton)	No. 2 Fuel Oil Heating Value (Btu/gal)	No. 2 Fuel Oil Required to Replace TDF (Mgal)	SO_2 Emissions from No. 2 Fuel Oil Combustion to Replace Bark (tpy)	Cost of No. 2 Fuel Oil ($/bbl)	Cost to Purchase Replacement No. 2 Fuel Oil ($)	Cost per ton ($/ton)
3,508	109,051	67	$548,763	1,031	106	0.03	$3,306	$349,693	($2,988)	$4,852	$513,290	($532)	138,000	790	0.08	$77	$1,451,056	$13,554

1. Fuel oil consumption, SO_2 emissions from fuel oil, and natural gas heating value are based on the most recent 3 calendar years of data (2017 - 2019).
2. SO2 emissions from natural gas combustion are based on the SO_2 emission factor from AP-42, Section 1.4, Table 1.4-2 (0.6 lb/MMscf).
3. The natural gas required to replace No. 6 fuel oil is calculated as follows:
Natural Gas Required to Replace TDF (MMMscf) = Heat Input from TDF (MMBtu) / Heat Content of Natural Gas (Btu/scf)
4. Cost data provided by the fuel vendor.

Emission Factor for No. 2 Fuel Oil	142 S	lb/Mgal, Table 1.3-1 of AP-42
Sulfur Content of No. 2 Fuel Oil	0.0015	%S for ULSD
No. 2 Fuel Oil Cost	77.12	$/bbl, average value

Cost Evaluation for the Replacement of No. 6 Fuel Oil with Natural Gas in the No. 4 Power Boiler

Fuel Oil Usage (Mgal)	Heat Input from No. 6 Fuel Oil (MMBtu)	SO_2 Emissions from No. 6 Fuel Oil Combustion (tpy)	Natural Gas Heating Value (MMBtu/MMscf)	Natural Gas Required to Replace No. 6 Fuel Oil (MMscf)	SO_2 Emissions from Natural Gas Combustion to Replace No. 6 Fuel Oil (tpy)	Using 2019 Average Price			Including Additional Curtailment Cost		
						Cost of Natural Gas ($/MMscf)	Cost to Purchase Replacement Natural Gas ($)	Cost per ton ($/ton)	Cost of Natural Gas ($/MMscf)	Cost to Purchase Replacement Natural Gas ($)	Cost per ton ($/ton)
374	56,939	49	1,031	55	0.02	$3,306	$182,617	$3,742	$4,852	$268,050	$5,492

1. Fuel oil consumption, SO_2 emissions from fuel oil, and natural gas heating value are based on the most recent 3 calendar years of data (2017 - 2019).
2. SO2 emissions from natural gas combustion are based on the SO_2 emission factor from AP-42, Section 1.4, Table 1.4-2 (0.6 lb/MMscf).
3. The natural gas required to replace No. 6 fuel oil is calculated as follows:

Natural Gas Required to Replace No. 6 Fuel Oil (MMMscf) = Heat Input from No. 6 Fuel Oil (MMBtu) / Heat Content of Natural Gas (Btu/scf)

Cost Evaluation for the Replacement of No. 6 Fuel Oil with Natural Gas in the No. 5 Recovery Furnace

						Using 2019 Average Price			Including Additional Curtailment Cost		
Fuel Oil Usage (Mgal)	Heat Input from No. 6 Fuel Oil (MMBtu)	SO_2 Emissions from No. 6 Fuel Oil Combustion (tpy)	Natural Gas Heating Value (MMBtu/MMscf)	Natural Gas Required to Replace No. 6 Fuel Oil (MMscf)	SO_2 Emissions from Natural Gas Combustion to Replace No. 6 Fuel Oil (tpy)	Cost of Natural Gas ($/MMscf)	Cost to Purchase Replacement Natural Gas ($)	Cost per ton ($/ton)	Cost of Natural Gas ($/MMscf)	Cost to Purchase Replacement Natural Gas ($)	Cost per ton ($/ton)
761	115,817	99	1,031	112	0.03	$3,306	$371,391	$3,766	$4,852	$545,139	$5,528

1. Fuel oil consumption, SO_2 emissions from fuel oil, and natural gas heating value are based on the most recent 3 calendar years of data (2017 - 2019).
2. SO2 emissions from natural gas combustion are based on the SO_2 emission factor from AP-42, Section 1.4, Table 1.4-2 (0.6 lb/MMscf).
3. The natural gas required to replace No. 6 fuel oil is calculated as follows:

Natural Gas Required to Replace No. 6 Fuel Oil (MMMscf) = Heat Input from No. 6 Fuel Oil (MMBtu) / Heat Content of Natural Gas (Btu/scf)

Capital & Operating Cost Evaluation for Dual Fuel (NG and Fuel Oil) Burners for the No. 5 Recovery Furnace

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$5,483,423	Based on site -specific costs for dual fuel burners installed on the No. 6 Recovery Furnace, scaled to 2019 dollars based on CEPCI of 576.1 (2014) and 607.5 (2019)
Vendor Quoted Burner Heat Input (MMBtu/hr) =	664	
Required Heat Input (MMBtu/hr) =	437	
Engineering Factor =	1.0	Vendor quote includes auxiliary costs.
Total Capital Investment (TCI)	**$4,268,528**	Prorated from previous vendor quote based on capacity ratio raised to the power of 0.6
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0527	CRF = 3.25% interest (current bank prime rate as of 9/27/2021) and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$224,873***	***CRC = TCI × CRF***
Operating Costs		
Indirect Operating Costs (IOC)		
Insurance	$42,685	J = 1% × TCI
Administrative Charges	$85,371	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$128,056***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$352,929**	*AC = CRC + DOC + IOC*
SO_2 Emissions (tpy)	98.6	Fuel Oil
SO_2 Reduction (tpy)	98.6	Fuel Oil - Natural Gas
Cost per ton of SO2 Removed ($/ton)	**$3,579**	**$/ton = AC / Pollutant Removed**

1. TCI per quote provided for another similar emission unit at the site, 2014 ratioed to 2019 dollars.
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

Cost Evaluation for the Use of a Lower Sulfur Fuel Oil in the No. 4 Power Boiler, No. 5 Recovery Furnace, and No 5 Lime Kiln

				1.5% Sulfur Fuel Oil					1% Sulfur Fuel Oil					No. 2 Fuel Oil				
No. 6 Fuel Oil Usage - Total for all Three Units (Mgal)	No. 6 Fuel Oil Usage - Total for the No. 4 Power Boiler and No. 5 Recovery Furnace (Mgal)	Heat Input from No. 6 Fuel Oil (MMBtu)	SO_2 Emissions from No. 6 Fuel Oil Combustion (tpy)	Heat Content of 1.5% Sulfur Fuel Oil (Btu/gal)	Additional 1.5% Sulfur Fuel Required (Mgal)	SO_2 Emissions from 1.5% Sulfur Fuel Oil (tpy)	Cost of Fuel Replacement ($)	Cost per ton ($/ton)	Heat Content of 1% Sulfur Fuel Oil (Btu/gal)	Additional 1% Sulfur Fuel Required (Mgal)	SO_2 Emissions from 1% Sulfur Fuel Oil (tpy)	Cost of Fuel Replacement ($)	Cost per ton ($/ton)	Heat Content of No. 2 Fuel Oil (Btu/gal)	Additional No. 2 Fuel Oil Required (Mgal)	SO_2 Emissions from No. 2 Fuel Oil (tpy)	Cost of Fuel Replacement ($)	Cost per ton ($/ton)
1,613	1,135	245,565	149	147,506	51	140	$120,794	$14,530	145,465	75	95	$186,798	$3,779	138,000	166	2.20	$937,212	$6,487

Capital & Operating Cost Evaluation for Combustion Unit Modifications

Cost Category	Value	Notes
Approximate Combustion Modification Costs ($) =	$345,000	Includes modifications for all three emission units
Total Capital Investment (TCI)	**$345,000**	
Capital Recovery		
Capital Recovery Factor (CRF)	0.0527	CRF = 3.25% interest (current bank prime rate as of 9/27/2021) and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$18,175***	***CRC = TCI × CRF***
Total Annualized Cost (AC) =	**$18,175**	*AC = CRC + DOC + IOC*

Cost Evaluation for the Use of a Lower Sulfur Fuel Oil in the No. 4 Power Boiler, No. 5 Recovery Furnace, and No 5 Lime Kiln, continued

Notes

1. Fuel consumption values and SO_2 emissions from combusting No. 6 fuel oil are based on the most recent 3 calendar years of operating data (2017 - 2019).
2. Cost data and blended fuel heat content provided by the fuel vendor.

Cost of No. 6 Fuel Oil =	$60.66	$/bbl
Incremental Additional Cost for Blended Fuel =	$1.18	$/bbl for 1.5% Sulfur Fuel Oil
	$1.96	$/bbl for 1% Sulfur Fuel Oil
Cost of No. 2 Fuel Oil =	$77.12	$/bbl, average value

3. Other data used in the calculations:

Emission Factor for No. 6 Fuel Oil =	157 S	lb/Mgal, Table 1.3-1 of AP-42, where S is the fuel sulfur content as a percentage
Emission Factor for No. 2 Fuel Oil =	142 S	lb/Mgal, Table 1.3-1 of AP-42, where S is the fuel sulfur content as a percentage
Sulfur Content of No. 2 Fuel Oil =	0.0015	%S for ULSD

4. The additional fuel required for each blended fuel is calculated as follows:

Additional Fuel Required (Mgal) = [Heat Input from No. 6 Fuel Oil (MMBtu) * 1,000,000 Btu/MMBtu / Heat Content of Blended Fuel (Btu/gal)] / 1000 gal/Mgal - No. 6 Fuel Oil Usage for All Three Units (Mgal)

The additional fuel requirement for each emission unit is calculated as follows:

Emission Unit	No. 6 Fuel Oil Usage (Mgal)	No. 6 Fuel Oil Heat Input (MMBtu)	Additional 1.5% Sulfur Fuel Required (Mgal)	Additional 1% Sulfur Fuel Required (Mgal)
No. 4 Power Boiler	374	56,939	12	18
No. 5 Recovery Furnace	761	115,817	24	35
No. 5 Lime Kiln	479	72,808	15	22

5. The SO2 emission rate for the blended fuels was calculated as follows:

SO_2 Emissions from Blended Fuel Combustion (tpy) = [Existing Fuel Oil Usage for the No. 4 Power Boiler and No. 5 Recovery Furnace (Mgal) + Additional Fuel Oil Required for the No. 4 Power Boiler and No. 5 Recovery Furnace (Mgal)] * [157 * Fuel Sulfur Content (%)] lb SO_2/Mgal / 2,000 lb/ton + 3-Year Average SO_2 Emission Rate for the No. 5 Lime Kiln

6. The cost of fuel replacement is calculated as follows:

Cost ($) = Fuel Oil Usage for All Three Units (Mgal) * 1000 gal/Mgal / 42 gal/bbl * Incremental Cost of Blended Fuel ($/bbl) + Additional Fuel Required (Mgal) * 1000 gal/Mgal / 42 gal/bbl * (Cost of No. 6 Fuel Oil ($/bbl) + Incremental Cost of Blended Fuel ($/bbl))

7. The cost per ton of SO_2 removed is calculated as follows:

Cost per ton ($/ton) = [Cost of Fuel Replacement ($) + Annualized Cost of Equipment Modifications ($)] / [$SO_2$ Emissions from Firing No. 6 Fuel Oil (tons) - SO_2 Emissions from Firing Blended Fuel (tons)]

Cost Evaluation for the Use of a Lower Sulfur Fuel Oil in the No. 4 Power Boiler and No. 5 Recovery Furnace

			1.5% Sulfur Fuel Oil					1% Sulfur Fuel Oil					No. 2 Fuel Oil				
No. 6 Fuel Oil Usage - Total for the No. 4 Power Boiler and No. 5 Recovery Furnace (Mgal)	Heat Input from No. 6 Fuel Oil (MMBtu)	SO_2 Emissions from No. 6 Fuel Oil Combustion (tpy)	Heat Content of 1.5% Sulfur Fuel Oil (Btu/gal)	Additional 1.5% Sulfur Fuel Required (Mgal)	SO_2 Emissions from 1.5% Sulfur Fuel Oil (tpy)	Cost of Fuel Replacement ($)	Cost per ton ($/ton)	Heat Content of 1% Sulfur Fuel Oil (Btu/gal)	Additional 1% Sulfur Fuel Required (Mgal)	SO_2 Emissions from 1% Sulfur Fuel Oil (tpy)	Cost of Fuel Replacement ($)	Cost per ton ($/ton)	Heat Content of No. 2 Fuel Oil (Btu/gal)	Additional No. 2 Fuel Oil Required (Mgal)	SO_2 Emissions from No. 2 Fuel Oil (tpy)	Cost of Fuel Replacement ($)	Cost per ton ($/ton)
1,135	172,756	147	147,506	36	138	$85,284	$16,235	145,465	53	93	$131,718	$3,719	138,000	117	0.13	$659,639	$4,952

Capital & Operating Cost Evaluation for Combustion Modifications and a New Fuel Oil Tank

Cost Category	Value	Notes
Approximate Combustion Modification Costs ($) =	$230,000	
Approximate Tank Costs ($) =	$700,000	Approximate cost for a 500,000-gal fuel oil tank based on similar installations at other sites
Total Capital Investment (TCI)	**$930,000**	
Capital Recovery		
Capital Recovery Factor (CRF)	0.0527	CRF = 3.25% interest (current bank prime rate as of 9/27/2021) and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$48,994***	***CRC = TCI × CRF***
Indirect Operating Costs (IOC) - New Storage Tank Only		
Insurance	$7,000	J = 1% × TCI
Administrative Charges	$14,000	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$21,000***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$69,994**	*AC = CRC + DOC + IOC*

Cost Evaluation for the Use of a Lower Sulfur Fuel Oil in the No. 4 Power Boiler and No. 5 Recovery Furnace, continued

Notes

1. Fuel consumption values in this table are based on the most recent 3 calendar years of operating data (2017 - 2019).
2. Cost data and blended fuel heat content provided by the fuel vendor.

Cost of No. 6 Fuel Oil =	$60.66	$/bbl
Incremental Additional Cost for Blended Fuel =	$1.18	$/bbl for 1.5% Sulfur Fuel Oil
	$1.96	$/bbl for 1% Sulfur Fuel Oil
Cost of No. 2 Fuel Oil =	$77.12	$/bbl, average value

3. Other data used in the calculations:

Emission Factor for No. 6 Fuel Oil =	157 S	lb/Mgal, Table 1.3-1 of AP-42, where S is the fuel sulfur content as a percentage
Emission Factor for No. 2 Fuel Oil =	142 S	lb/Mgal, Table 1.3-1 of AP-42, where S is the fuel sulfur content as a percentage
Sulfur Content of No. 2 Fuel Oil =	0.0015	%S for ULSD

4. The additional fuel required for each blended fuel is calculated as follows:

Additional Fuel Required (Mgal) = [Heat Input from No. 6 Fuel Oil (MMBtu) * 1,000,000 Btu/MMBtu / Heat Content of Blended Fuel (Btu/gal)] / 1000 gal/Mgal - No. 6 Fuel Oil Usage for No. 4 Power Boiler and No. 5 Recovery Furnace (Mgal)

The additional fuel requirement was calculated separately for each emission unit as follows:

Emission Unit	No. 6 Fuel Oil Usage (Mgal)	No. 6 Fuel Oil Heat Input (MMBtu)	Additional 1.5% Sulfur Fuel Required (Mgal)	Additional 1% Sulfur Fuel Required (Mgal)
No. 4 Power Boiler	374	56,939	12	18
No. 5 Recovery Furnace	761	115,817	24	35

5. The SO2 emission rate for the blended fuels was calculated as follows:

SO_2 Emissions from Blended Fuel Combustion (tpy) = [Existing Fuel Oil Usage for the No. 4 Power Boiler and No. 5 Recovery Furnace (Mgal) + Additional Fuel Oil Required for the No. 4 Power Boiler and No. 5 Recovery Furnace (Mgal)] * [157 * Fuel Sulfur Content (%)] lb SO_2/Mgal / 2,000 lb/ton + 3-Year Average SO_2 Emission Rate for the No. 5 Lime Kiln

6. The cost of fuel replacement is calculated as follows:

Cost ($) = Fuel Oil Usage for All Three Units (Mgal) * 1000 gal/Mgal / 42 gal/bbl * Incremental Cost of Blended Fuel ($/bbl) + Additional Fuel Required (Mgal) * 1000 gal/Mgal / 42 gal/bbl * (Cost of No. 6 Fuel Oil ($/bbl) + Incremental Cost of Alternative Fuel ($/bbl))

7. The cost per ton of SO_2 removed is calculated as follows:

Cost per ton ($/ton) = [Cost of Fuel Replacement ($) + Annualized Cost of Equipment Modifications and Storage Tank ($)] / [$SO_2$ Emissions from Firing No. 6 Fuel Oil (tons) - SO_2 Emissions from Firing Alternative Fuel (tons)]