APPENDIX B

Florida Department of Environmental Protection
Division of Air Resource Management

Regional Haze Supplemental SIP Part II
Four Factor Analyses and Documentation

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Regional Haze Rule – Reasonable Progress Analysis

for

Foley Cellulose LLC
Facility ID No. 1230001
One Buckeye Drive
Perry, Taylor County, Florida

Submitted to the
Florida Department of Environmental Protection

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APPENDIX A **RBLC SUMMARY**

APPENDIX B **CONTROL COST ESTIMATES**

1. EXECUTIVE SUMMARY

Foley Cellulose LLC, a wholly owned subsidiary of Georgia-Pacific LLC (GP), owns and operates a softwood Kraft pulp mill (referred to as the "Foley Mill" or the "Mill") located in Perry, Taylor County, Florida that manufacturers bleached market, fluff, and specialty dissolving cellulose pulp. The Foley 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. 1230001-087-AV), most recently issued by the Florida Department of Environmental Protection (FDEP) on January 6, 2020.

On June 22, 2020, FDEP issued a letter to the Foley Mill requesting an analysis for the following emission units demonstrating that the unit is already effectively-controlled under an enforceable requirement or that the Mill provide a reasonable progress four-factor analysis (FFA) for sulfur dioxide (SO_2) :

- EU002 – No. 1 Power Boiler,
- EU004 – No. 1 Bark Boiler,
- EU006 – No. 2 Recovery Furnace,
- EU007 – No. 3 Recovery Furnace,
- EU011 – No. 4 Recovery Furnace, and
- EU019 – No. 2 Bark Boiler.

The four-factor analyses included in this submittal follow the August 20, 2019 United States Environmental Protection Agency's (EPA) guidance[1] 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

Details on the sources considered in the analysis are detailed below and summarized in Table 1-1.

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

Table 1-1 Source Summary

Unit ID	Name	3-Year Average SO_2 Emissions (tpy)	Fuels Fired	Controls
EU002	No. 1 Power Boiler	81	Natural Gas, No. 6 FO, Tall Oil, Used Oil, NCGs	TRS pre-scrubber
EU004	No. 1 Bark Boiler	188	Natural Gas, No. 6 FO, Tall Oil, Used Oil, Wood, NCGs	TRS pre-scrubber, Scrubber
EU006	No. 2 Recovery Furnace	307	BLS, No. 6 FO, Tall Oil, Used Oil, No. 2 FO, Natural Gas	ESP
EU007	No. 3 Recovery Furnace	573	BLS, No. 6 FO, Tall Oil, Used Oil, No. 2 FO, Natural Gas	ESP
EU011	No. 4 Recovery Furnace	618	BLS, No. 6 FO, Tall Oil, Used Oil, No. 2 FO, Natural Gas	ESP
EU019	No. 2 Bark Boiler	3	Natural Gas, No. 6 FO, Tall Oil, Used Oil, Wood	Scrubbers

The sources to be evaluated consist of boilers (EUs 002, 004, 019) and Recovery Furnaces (EUs 006, 007, 011), and the analyses are grouped into these two categories.

The No. 1 Power Boiler (EU 002) was built by Babcock and Wilcox in 1953. The boiler fires natural gas, No. 6 fuel oil, tall oil, and on-specification used oil. The No. 1 Power Boiler serves as the secondary control device for low volume, high concentration (LVHC) non-condensable gases (NCGs) up to 2,800 hours per year. The NCGs are routed to the total reduced sulfur (TRS) pre-scrubber before introduction to the boiler. The No. 1 Power Boiler is capable of serving the Mill with 195,000 pounds per hour (lbs/hr) of steam.

The No. 1 Bark Boiler (EU 004) fires carbonaceous fuel, consisting of wood materials such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; tall oil; and on-specification used oil. The boiler serves as the primary control device for LVHC NCGs. The No. 1 Bark Boiler is capable of serving the Mill with 200,000 lbs/hr (24-hour block average basis) of steam and is equipped with a cyclone collector and a wet venturi scrubber.

The No. 2 Bark Boiler (EU 019) fires carbonaceous fuel consisting, of wood materials such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; tall oil; and on-specification used oil. The boiler is capable of serving the Mill with 395,000 lbs/hr (24-hour block average basis) of steam. The flue gases from the No. 2 Bark Boiler are split into two streams: (1) one stream flowing through the economizer to a wet, Venturi scrubber, through the demister, and out the stack and (2) the other stream bypassing the economizer and going directly to a cyclone collector and a second wet, Venturi scrubber.

The Mill's three recovery furnaces (EUs 006, 007, and 011) are nondirect contact evaporator (NDCE) units and burn the organic material present in black liquor (black liquor solids, BLS). In addition to BLS, the Nos. 2, 3, and 4 Recovery Furnaces may also be fired with natural gas, No. 6 fuel oil, No. 2 fuel oil, tall oil, ultra-low sulfur diesel, on-specification used oil, and methanol (only in the Nos. 2 and 4 Recovery

Furnaces). Particulate matter emissions from the recovery furnaces are controlled by dedicated electrostatic precipitators (ESPs).

1.2. NO. 2 BARK BOILER

The FDEP letter requests analyses of sources projected to emit more than five tons per year (tpy) in 2028. Based on the last three years of data and operational plans going forward, the Foley Mill does not expect the No. 2 Bark Boiler (EU019) to emit more than five tpy of SO_2 in the future. Emissions for 2017, 2018, and 2019 were 3.8, 2.6, and 2.8 tpy of SO_2, respectively. The No. 2 Bark Boiler primarily fires wood fuel (bark) with natural gas and No. 6 fuel oil as ancillary fuels. SO_2 emissions from the No. 2 Bark Boiler are primarily from the firing of No. 6 fuel oil, which is only fired when there are issues with the natural gas line header pressure. The Mill does not expect to alter the current fuel mix going forward.

Based on discussions with FDEP, the Foley Mill understands that, based on these low emissions, a four-factor analysis is not required for the No. 2 Bark Boiler at this time.

1.3. REPORT CONTENTS

This four-factor analysis for the Foley Mill includes the following elements:

- Section 2 describes available control technologies,
- Section 3 provides the four-factor analysis 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 at the Foley Mill.

2. AVAILABLE SO_2 CONTROL TECHNOLOGIES

The following sections provide a brief description of potentially applicable control technologies for SO_2 control on the boilers 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[2], 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).

Technically feasible control technologies for industrial boilers and recovery furnaces were evaluated, taking into account current air pollution controls, fuels fired, and RBLC Database information.

2.2. GOOD OPERATING PRACTICES

Good operating practices for an industrial boiler are important, but are less likely to impact SO_2 emissions. For a recovery furnace, very low SO_2 emissions may be achieved from a well operated furnace. One of the primary purposes 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 levels in recovery furnaces 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. 2, 3, and 4 Recovery Furnaces are all NDCE units which typically have lower SO_2 emissions than direct contact evaporator (DCE) units due to improved combustion efficiency.

2.3. LOW-SULFUR FUELS

Fuel switching to natural gas was not evaluated because the purpose of this analysis is not to change the operation or design of the source or to evaluate alternative energy projects. The August 20, 2019 EPA 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. 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.[3]

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[2] 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.

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

2.4. WET SCRUBBER 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 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 No. 3 and No. 4 Recovery Furnaces (now shut down) 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 accomplishes removal of acid gases by injecting a dry reagent (*i.e.,* lime or trona) into the flue gas stream and 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 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 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 and add-on control technology (wet scrubber with caustic and DSI) based on four factors:

- 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.

For each source/add-on control device option analyzed, cost estimates were based on vendor data for similar sources and EPA guidance. Emissions used for cost effectiveness (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. As part of this review, an error was discovered in the reported emissions in 2018 for the No. 4 Recovery Furnace. The unit has an SO_2 continuous emissions monitoring system (CEMS) and emissions were reported based on the sum of the CEMS measurements and fuel oil emissions as calculated from AP-42 emission factors. However, the CEMS data captures all of the sources of emissions, so earlier reported emissions were over-estimated.

Although FDEP 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 used a cost effectiveness threshold of less than $5,000/ton when determining if it was 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 Cross-State Air Pollution Rule (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.
- 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 assumes that thresholds used by similar states of more than $5,000 per ton should not be considered cost effective.

3.1. NO. 1 POWER BOILER

The No. 1 Power Boiler (EU 002) fires natural gas, No. 6 fuel oil, tall oil, used oil, and serves as a backup for the control of NCGs. The primary fuel is natural gas, which results in very low SO_2 emissions. The majority of annual SO_2 emissions from the boiler are due to combustion of the NCGs, converting reduced sulfur compounds to SO_2 and water. When NCGs are routed to the No. 1 Power Boiler, a pre-scrubber is used to assist with reduction of TRS which in turn limits SO_2 production.

3.1.1. 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.[4] As this was the most recent quote for a similar unit available, the Lime Kiln scrubber cost estimate was used for the No. 1 Power Boiler by ratioing the flows to the 0.6 power.[5] Caustic use was based on the molar ratio of sodium hydroxide and SO_2 and an assumed a 10% loss. Electricity requirements, water use, and waste generation costs were based on a detailed vendor quote for a similar system at a GP facility in Georgia. These usage rates were scaled based on air flow. Facility costs for labor, water, waste, and caustic were based on the Mill's site-specific data or data from other similar facilities. The capital costs were annualized based on a 30-year life span and 5% interest rate as outlined in EPA's *DRAFT EPA SO_2 and Acid Gas Control Cost Manual.*[6]

Based on the cost information and emissions, a caustic scrubber would cost approximately $13,500 per ton of SO_2 removed, which is not cost effective.

3.1.2. Dry Sorbent Injection

The capital cost for a system to inject milled trona was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[7] 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, without a fabric filter, is approximately $21,700 per ton of SO_2 removed, which is not cost effective. A new baghouse would also have to be installed to collect the dry by-product, which would be an additive cost. As the costs of DSI alone were not cost effective, the additional cost of a baghouse was not included.

3.2. NO. 1 BARK BOILER

The No. 1 Bark Boiler (EU 004) fires carbonaceous fuel, consisting of wood materials such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; tall oil; and on-specification used oil. The boiler serves as the primary control device for NCGs. The No. 1 Bark Boiler is equipped with a cyclone collector and a wet venturi scrubber. When NCGs are vented to the No. 1 Bark Boiler, a pre-scrubber is also utilized. If the pre-scrubber is not operational, caustic is injected into the wet venturi scrubber. As the No. 1 Bark

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[4] 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 Foley boiler and the details of the lime kiln proposal.

[5] EPA, *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*, July 2020, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control.

[6] *Ibid.*

[7] Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology*. Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

Boiler is already equipped with a scrubber, only the addition of more caustic is evaluated. DSI is not analyzed as the scrubber would have to be replaced with a dry control device. The DSI costs would be in a similar range as those for the No. 1 Power Boiler, which are not cost effective on their own, in addition to the costs associated with removal of an existing control device.

In addition to caustic addition, anti-scalant must be added to minimize fouling and scaling due to caustic buildup in the boiler. Based on current caustic and anti-scalant prices and the molar ratio of sodium hydroxide and SO_2, additional SO_2 reduction can be achieved at an estimated cost of $2,600/ton by using caustic in the scrubber in place of using the TRS pre-scrubber.

3.3. NOS. 2, 3, AND 4 RECOVERY FURNACES

In the Mill's three recovery furnaces (EUs 006, 007, and 011), the organic material present in black liquor is oxidized as the carbon is burned away and the inorganic compounds are smelted in reduction reactions for reuse in the pulping process. 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 (EUs 021, 022, and 023). Salt cake, reclaimed from the economizer and the electrostatic precipitator (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 furnace or sent to a strong black liquor storage tank. In addition to BLS, the Nos. 2, 3, and 4 Recovery Furnaces may also be fired with natural gas, No. 6 fuel oil, No. 2 fuel oil, tall oil, ultra-low sulfur diesel, on-specification used oil, and methanol (only in the Nos. 2 and 4 Recovery Furnaces). Particulate matter emissions from the recovery furnaces are controlled by dedicated ESPs.

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.[8] Costs were scaled to 2019[9] dollars and 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 actual BLS throughput. Facility costs for labor, water, waste, and caustic were based on the Mill's site-specific data or data from other similar facilities. The capital costs were annualized based on a 30-year life span and 5% interest rate as outlined in EPA's DRAFT EPA SO_2 and Acid Gas Control Cost Manual.[10]

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[11],which estimates

[8] http://www.nescaum.org/documents/bart-resource-guide/be-k-capital-operating-cost-estimate-9-20-01.pdf/
[9] The most recent complete year of the Chemical Engineering Plant Cost Index (CEPCI) was used.
[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] 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

annual operating costs between $3 and 9 million per year. The costs in the Mill's analysis were between $2.8 and 3.8 million per year.

Based on the cost information and emissions, a caustic scrubber would cost approximately $9,300, $5,100, and $6,300 per ton of SO_2 removed for the Nos. 2, 3, and 4 Recovery Furnaces, respectively. These values are not considered cost effective. Moreover, the Foley Mill believes that the actual value will be significantly higher due to costs associated with retrofitting the scrubber on an existing emissions unit.

3.4. 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. DSI results in additional waste being generated.

3.5. Time Necessary for Compliance

EPA allows three years plus an optional extra year for compliance with 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 are ultimately required to meet Regional Haze Rule (RHR) requirements, facilities would need at least four to five years to implement add-on controls after final EPA approval of the RHR SIP. The Mill would need time to obtain corporate approvals for capital funding. The facility would have to undergo substantial re-engineering (*e.g.,* due to space constraints) 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.

3.6. Remaining Useful Life

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

4. SUMMARY OF FINDINGS

The Foley Mill analyzed the significant SO_2 emissions sources for additional control utilizing EPA's four-factor method. Based on this analysis, no add-on controls are deemed feasible or cost-effective. The use of caustic in the venturi scrubber for the No. 1 Bark Boiler when combusting NCGs may be considered cost-effective. But the expected amount of emissions reduction by adding caustic is only approximately 96 tpy of SO_2, which is unlikely to have a measurable impact on regional haze at the Okefenokee National Wildlife Refuge.

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

Supporting Data for Control Device Cost Effectiveness Calculations

Parameter	Value		Note(s)
Operating Labor Cost	30.68	\$/hr	1
Maintenance Labor Cost	32.15	\$/hr	1
Caustic Cost	480	\$/ton	1
Electricity Cost	0.0755	\$/kWh	1
Water Cost	0.86	\$/Mgal	2
Wastewater Treatment Cost	0.64	\$/Mgal	1

1. Labor, caustic, electricity, and wastewater based on Foley specific data.
2. Water cost based on data from similar facilities.

Chemical, Energy, Water Use Basis

Amount of NaOH per SO2, based on molar ratio	1.25	lb/lb SO2 Removed		
NaOH solution, 50%	2.5	lb/lb SO2 Removed		
Data for Recovery Furnace				
Electricty per AFPA data	440.92	kW/MMlb BLS		
Freshwater use per AFPA Data	40.00	gpm/(MMlb BLS/day)		
Wastewater disposal per AFPA Data	4.00	gpm/(MMlb BLS/day)		
Data for Boiler	Reference is		420,000	acfm
Electricity per previous BART Control data	0.00175	KWhr/acfm		
Freshwater use per previous BART Data	0.233	Mgal/acfm		
Wastewater disposal per Previous BART data	0.082	Mgal/acfm		

1. Caustic use based on $2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$
2. Usage of electricity, water, and waste based on reference cost estimates for controls.
   AFPA data basis is http://www.nescaum.org/documents/bart-resource-guide/be-k-capital-operating-cost-estimate-9-20-01.pdf/
   Previous BART Data is based on a 2008 BART control submittal for a similar GP unit.

Foley PB1

Capital and Annual Costs Associated with Trona Injection

Variable	Designation	Units	Value	Calculation
Heat Input		**MMBtu/hr**	**151.3**	
Unit Size	A	MW	13	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	0.124	Based on 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	1.51E+08	151.33 MMBtu/hr
NSR	K	-	2.61	Milled Trona w/ FF = 0.208e^(0.0281*H)
Sorbent Feed Rate	M	ton/hr	0.20	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	0.16	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	0.00	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV; fires primarily natural gas, set to zero.
Aux Power	Q	%	0.30	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	100	Default value for disposal without fly ash
Aux Power Cost	T	$/kWh	0.06	Default value in report
Operating Labor Rate	U	$/hr	49.09	Typical labor cost, includes 60% overhead cost

SO_2 Control Efficiency:	90%
Representative Emissions	81.3
Controlled SO_2 Emissions:	73.2

Capital Costs				
Direct Costs				
BM (Base Module) scaled to 2019 dollars		$	$ 5,864,531	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs				
Engineering & Construction Management	A1	$	$ 586,453	10% BM
Labor adjustment	A2	$	$ 293,227	5% BM
Contractor profit and fees	A3	$	$ 293,227	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$ 7,037,438	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$ 351,872	5% CEC
Total project cost w/out AFUDC	TPC	$	$ 7,389,309	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$	0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$ 7,389,309**	CECC+B1+B2

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	204,206	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	58,645	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	6,830	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**269,681**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	292,753	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	138,202	(N+P)*S
Additional auxiliary power required	VOMP	$	$	113,801	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**544,756**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	147,786	
Property Tax	1%	of TCI	$	73,893	
Insurance	1%	of TCI	$	73,893	
Capital Recovery	6.51%	x TCI	$	480,685	
Total Indirect Annual Costs			**$**	**776,258**	
Life of the Control:		30 years		5.00%	interest
Total Annual Costs			**$**	**1,590,695**	
Total Annual Costs/SO_2 Emissions			**$**	**21,727**	

[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 SO2 Scrubber for PB1

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$7,200,000	Based on 2020 cost estimate for Lime Kiln for similar 4-factor Analysis
Vendor Quoted System (cfm) =	124,500	
CFM analyzed	115,770	
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$6,892,686**	Prorated from previous vendor quote based on capacity ratio raised to the power of
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Contro
Capital Recovery Cost (CRC)	***$448,714***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$105,230	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	202	Power (kWh) ratioed based on similar boiler cost estimate values.
Cost of Electricity Usage	$133,793	F = E × Electricity Cost
Fresh Water	$23,199	G = Freshwater use * water cost
Water Disposal	$6,065	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$322,808***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$68,927	I = 1% × TCI
Insurance	$68,927	J = 1% × TCI
Administrative Charges	$137,854	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$308,420***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$1,079,942**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	81.35	
SO_2 Removed (tpy)	79.72	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$13,547**	**$/ton = AC / Pollutant Removed**

1. TCI per 2020 Envitech estimate for 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.

Operating Cost Evaluation for SO2 Caustic Addition for BB1

Emission Rate with Caustic (lb/ADTUBP)	1.74	
Emission Rate without Caustic and with Pre-scrubber (lb/ADTUBP)	3.54	
% Control - caustic	51%	
Caustic Use	2.5	lb NaOH per lb SO2 removed
Caustic Loss	10%	
Caustic Cost	480	$/ton Caustic
Anti-scaler	$125,000	per year
Cost per ton of SO_2 removed, Caustic	$1,320	$/ton
Cost per ton of SO_2 removed, Anti-Scaler	$1,307	$/ton
Total tons reduced	96	tons
Total cost per ton	$2,627	

1. Emissions rates based on stack test data and % control represents improvement over operation with pre-scrubber.
2. Caustic use based on molar ratio.
3. Anti-scaler based on estimated cost of using caustic full time and improved caustic control.

Capital & Operating Cost Evaluation for SO2 Scrubber for RF2

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 (2(
Vendor Quoted System BLS (ton BLS/day) =	1,850	AFPA 2001 Data
BLS Analyzed (ton BLS/day) =	1,171	Permitted Capacity
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$15,041,601**	Prorated from previous vendor quote based on capacity ratio raised to the power of
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Contr
Capital Recovery Cost (CRC)	***$979,208***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$397,010	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	1,033 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$683,086	F = E × Electricity Cost
Fresh Water	$42,352	G = Freshwater use * water cost
Water Disposal	$3,139	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$1,180,109***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$150,416	I = 1% × TCI
Insurance	$150,416	J = 1% × TCI
Administrative Charges	$300,832	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$634,377***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$2,793,693**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	306.90	
SO_2 Removed (tpy)	300.77	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$9,289**	**$/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 SO2 Scrubber for RF3

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 (20:
Vendor Quoted System BLS (ton BLS/day) =	1,850	AFPA 2001 Data
BLS Analyzed (ton BLS/day) =	988	Permitted Capacity
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$13,583,833**	Prorated from previous vendor quote based on capacity ratio raised to the power of 0
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control
Capital Recovery Cost (CRC)	***$884,308***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$741,401	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	871 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$576,354	F = E × Electricity Cost
Fresh Water	$35,735	G = Freshwater use * water cost
Water Disposal	$2,648	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$1,410,659***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$135,838	I = 1% × TCI
Insurance	$135,838	J = 1% × TCI
Administrative Charges	$271,677	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$576,066***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$2,871,033**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	573.13	
SO_2 Removed (tpy)	561.67	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$5,112**	**$/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 SO2 Scrubber for RF4

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 (20:
Vendor Quoted System BLS (ton BLS/day) =	1,850	AFPA 2001 Data
BLS Analyzed (ton BLS/day) =	1,606	Permitted Capacity
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$18,178,017**	Prorated from previous vendor quote based on capacity ratio raised to the power of 0
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control
Capital Recovery Cost (CRC)	***$1,183,389***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$799,540	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	1,416 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$936,619	F = E × Electricity Cost
Fresh Water	$58,071	G = Freshwater use * water cost
Water Disposal	$4,304	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$1,853,055***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$181,780	I = 1% × TCI
Insurance	$181,780	J = 1% × TCI
Administrative Charges	$363,560	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$759,833***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$3,796,278**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	618.07	
SO_2 Removed (tpy)	605.71	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$6,267**	**$/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.

gpcellulose
Foley Cellulose

ONE BUCKEYE DRIVE
PERRY, FLORIDA 32348-7702

August 30, 2022

Mr. Hastings Read
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Foley Cellulose LLC
Facility ID No. 1230001
Regional Haze Rule – Reasonable Progress Analysis

Dear Mr. Read:

Foley Cellulose LLC owns and operates a softwood Kraft pulp mill (referred to as "GP", the "Foley Mill" or the "Mill") located in Perry, Taylor County, Florida that manufactures bleached market, fluff, and specialty dissolving cellulose pulp. The Foley 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. 1230001-106-AV), most recently issued by the Florida Department of Environmental Protection (FDEP) on March 22, 2022.

On June 22, 2020, FDEP issued a letter to the Foley Mill requesting a four-factor analysis for sulfur dioxide (SO_2) for the following emission units:

- EU002 – No. 1 Power Boiler
- EU004 – No. 1. Bark Boiler
- EU006 – No. 2 Recovery Boiler
- EU007 – No. 3 Recovery Boiler
- EU011 – No. 4 Recovery Boiler
- EU019 – No. 2 Bark Boiler

The Foley Mill submitted an initial analysis to FDEP on October 20, 2020. Based on discussions with FDEP and additional analyses conducted at the Foley Mill, GP submits this updated four factor analysis. Revised control costs for add-on pollution control devices for the Nos. 2, 3, and 4 Recovery Furnaces are provided in an attachment to this letter. The revised costs are based on more accurate sulfur dioxide (SO_2) emissions data and site-specific cost estimates for controls.

Based on the updated analyses, GP is proposing the following changes at the facility in support of the Regional Haze rule:

- Limit No. 6 fuel oil sulfur content to 1.02%, averaged over a 12-month period as purchased.
- Maintain pH of at least 8 for the No. 1 Bark Boiler's venturi scrubber when non-condensable gases (NCGs) are routed to the boiler for control, even when the TRS Pre-Scrubber is in service.
- Cap No. 6 fuel oil firing for No. 1 Power Boiler and Nos. 1 and 2 Bark Boilers. GP proposes a combined cap of 3,500,000 gallons/year, excluding usage necessitated by any natural gas curtailment. The cap will be demonstrated on a 12-month rolling basis.
- Based on the updated control cost analysis provided as an attachment to this letter, add-on controls are not cost-effective for the Nos. 2, 3 or 4 Recovery Furnaces.

If you have any questions about the attached analysis, please do not hesitate to contact Dean Ahrens at (850) 584-1608 or via email at jerry.ahrens@gapac.com or Maria Zufall at (404) 652-7256 or Maria.Zufall@gapac.com.

Sincerely,

Thomas Pazdera
Vice President – General Manager
Foley Cellulose LLC

Attachment

Capital & Operating Cost Evaluation for SO2 Scrubber for RF2

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,171	Permitted Capacity
Total Capital Investment (TCI)	**$22,000,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$1,432,200***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Labor	$17,780	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,780	D = Equivalent to maintenance labor
Caustic Costs†	$1,085,018	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$226,422	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,033 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$753,808	F = E × Electricity Cost
Fresh Water	$38,334	G = Freshwater use * water cost
Water Disposal	$3,139	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$2,159,882***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$31,896	H = 60% × (A + B + C + D)
Property Tax	$220,000	I = 1% × TCI
Insurance	$220,000	J = 1% × TCI
Administrative Charges	$440,000	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$911,896***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$4,503,978**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	657.59	
SO_2 Removed (tpy)	591.83	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$7,610**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for August 2021 through July 2022. During this timeframe, the monthly values have varied from $440/ton to $920/ton.

Capital & Operating Cost Evaluation for SO2 Scrubber for RF3

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	988	Permitted Capacity
Total Capital Investment (TCI)	**$22,000,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$1,432,200***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Labor	$17,780	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,780	D = Equivalent to maintenance labor
Caustic Costs†	$1,924,725	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$401,653	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	871 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$636,025	F = E × Electricity Cost
Fresh Water	$32,344	G = Freshwater use * water cost
Water Disposal	$2,648	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$3,050,557***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$31,896	H = 60% × (A + B + C + D)
Property Tax	$220,000	I = 1% × TCI
Insurance	$220,000	J = 1% × TCI
Administrative Charges	$440,000	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$911,896***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$5,394,654**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	1,167	
SO_2 Removed (tpy)	1,050	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$5,138**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for August 2021 through July 2022. During this timeframe, the monthly values have varied from $440/ton to $920/ton.

Capital & Operating Cost Evaluation for SO2 Scrubber for RF4

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,606	Permitted Capacity
Total Capital Investment (TCI)	**$22,000,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$1,432,200***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Labor	$17,780	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,780	D = Equivalent to maintenance labor
Caustic Costs†	$1,524,270	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$318,086	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,416 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$1,033,589	F = E × Electricity Cost
Fresh Water	$52,562	G = Freshwater use * water cost
Water Disposal	$4,304	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$2,985,972***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$31,896	H = 60% × (A + B + C + D)
Property Tax	$220,000	I = 1% × TCI
Insurance	$220,000	J = 1% × TCI
Administrative Charges	$440,000	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$911,896***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$5,330,068**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	924	
SO_2 Removed (tpy)	831	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$6,411**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for August 2021 through July 2022. During this timeframe, the monthly values have varied from $440/ton to $920/ton.

gpcellulose
Foley Cellulose
ONE BUCKEYE DRIVE
PERRY, FLORIDA 32348-7702

November 16, 2022

Mr. Hastings Read
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Foley Cellulose LLC
Facility ID No. 1230001
Regional Haze Rule – November 2022 Update

Dear Mr. Read:

Foley Cellulose LLC owns and operates a softwood Kraft pulp mill (referred to as "GP", the "Foley Mill" or the "Mill") located in Perry, Taylor County, Florida that manufactures bleached market, fluff, and specialty dissolving cellulose pulp. The Foley 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. 1230001-106-AV), most recently issued by the Florida Department of Environmental Protection (FDEP) on March 22, 2022.

On June 22, 2020, under the Regional Haze regulation, 40 CFR 51.308, FDEP issued a letter to the Foley Mill requesting a four-factor analysis for sulfur dioxide (SO_2) for the following emission units:

- EU002 – No. 1 Power Boiler
- EU004 – No. 1 Bark Boiler
- EU006 – No. 2 Recovery Boiler
- EU007 – No. 3 Recovery Boiler
- EU011 – No. 4 Recovery Boiler
- EU019 – No. 2 Bark Boiler

The Foley Mill submitted an initial analysis to FDEP on October 20, 2020. An updated analysis was submitted on August 30, 2022. On September 20, 2022, representatives from FDEP met at the Foley Mill to discuss the four-factor analysis. Based on that meeting, the following updates are being submitted with this letter.

Revised Control Cost Analysis. Based on discussions with FDEP, review of recent EPA cost control manual guidance, and a detailed review of cost data, the following changes were made to the control cost estimates:

- Scrubber costs were provided by the vendor for each individual recovery furnace to reflect different costs based on size and configuration.
- The property tax, insurance, and administrative costs were removed from the analysis.
- Capital recovery factor was updated to the current prime rate and 30-year life.
- Maintenance costs were updated to reflect the most recent control cost manual guidance. These values were also confirmed with internal engineering resources.
- Material costs were updated with the most current data through October 2022.

The updated control costs for add-on pollution control devices for the Nos. 2, 3, and 4 Recovery Furnaces are provided as an attachment to this letter. The control costs are approximately $7,800, $5,200, and $6,600 per ton, respectively for the Nos. 2, 3 and 4 Recovery Furnaces. Therefore, add-on controls are not cost-effective.

As requested, technical background information on the Foley recovery furnaces is also provided in an attachment.

Proposed Permit Conditions. Based on the updated analyses, GP is proposing the following permit conditions to reduce emissions and satisfy any additional requirements under the Regional Haze Rule:

- Limit No. 6 fuel oil sulfur content to 1.02%, averaged over a 12-month period as purchased.
- Maintain pH of at least 8.0 for the No. 1 Bark Boiler's venturi scrubber when non-condensable gases (NCGs) are being routed to the boiler for control, even when the TRS Pre-Scrubber is in service.
- Cap No. 6 fuel oil firing for No. 1 Power Boiler and Nos. 1 and 2 Bark Boilers. GP proposes a combined cap of 3,500,000 gallons/year, excluding usage necessitated by any natural gas curtailment. The cap will be demonstrated on a 12-month rolling basis.
- Cap the combined Nos. 2, 3, and 4 Recovery Furnace SO_2 emissions at 3,325 tons per year.

GP will submit a permit application to incorporate these conditions into the permit pending FDEP's concurrence. If you have any questions about the attached analysis, please do not hesitate to contact Dean Ahrens at (850) 584-1608 or via email at jerry.ahrens@gapac.com or Maria Zufall at (404) 652-7256 or Maria.Zufall@gapac.com.

Sincerely,

Thomas Pazdera
Vice President – General Manager
Foley Cellulose LLC

Attachments

ATTACHMENT 1
CONTROL COST CALCULATIONS

Total Capital Investment (TCI) - No. 2 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$22,000,000**
Equipment	
Andrtiz SO2 Scrubber Package	$5,735,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$544,800
	$7,354,800
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$525,000
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,250,000
	$7,825,000
Balance of Plant (7%)	**$1,062,586**
Project Costs	
Engineering (10%)	$1,624,239
Project Management (5%)	$812,119
Construction Management (2.5%)	$406,060
Escalation (8%)	$1,299,391
Contingency (10%)	$1,624,239
	$5,766,047

Capital & Operating Cost Evaluation for SO2 Scrubber for No. 2 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,171	Permitted Capacity
Total Capital Investment (TCI)	**$22,000,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cost (CRC)	***$1,772,901***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Costs	$330,000	C = Based 0.015 TCI, per May 2021 FGD control cost manual
Caustic Costs†	$1,201,657	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$265,339	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,033 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$766,504	F = E × Electricity Cost
Fresh Water	$38,334	G = Freshwater use * water cost
Water Disposal	$3,139	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$2,622,575***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$208,561	H = 60% × (A + B + C + D)
Property Tax		I = 1% × TCI
Insurance		J = 1% × TCI
Administrative Charges		K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$208,561***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$4,604,037**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	657.59	
SO_2 Removed (tpy)	591.83	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$7,779**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. During this timeframe, the monthly values have varied from $460/ton to $920/ton.

Total Capital Investment (TCI) - No. 3 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$20,500,000**
Equipment	
Andrtiz SO2 Scrubber Package	$4,998,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$485,840
	$6,558,840
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$505,200
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,052,000
	$7,607,200
Balance of Plant (7%)	**$991,623**
Project Costs	
Engineering (10%)	$1,515,766
Project Management (5%)	$757,883
Construction Management (2.5%)	$378,942
Escalation (8%)	$1,212,613
Contingency (10%)	$1,515,766
	$5,380,970

Capital & Operating Cost Evaluation for SO2 Scrubber for No. 3 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	988	Permitted Capacity
Total Capital Investment (TCI)	**$20,500,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cost (CRC)	***$1,652,021***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Costs	$307,500	C = Based 0.015 TCI, per May 2021 FGD control cost manual
Caustic Costs†	$2,131,633	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$470,687	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	871 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$646,738	F = E × Electricity Cost
Fresh Water	$32,344	G = Freshwater use * water cost
Water Disposal	$2,648	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$3,609,153***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$195,061	H = 60% × (A + B + C + D)
Property Tax		I = 1% × TCI
Insurance		J = 1% × TCI
Administrative Charges		K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$195,061***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$5,456,235**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	1,167	
SO_2 Removed (tpy)	1,050	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$5,197**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. During this timeframe, the monthly values have varied from $460/ton to $920/ton.

Total Capital Investment (TCI) - No. 4 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$21,800,000**
Equipment	
Andrtiz SO2 Scrubber Package	$5,614,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$535,120
	$7,224,120
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$521,800
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,218,000
	$7,789,800
Balance of Plant (7%)	**$1,050,974**
Project Costs	
Engineering (10%)	$1,606,489
Project Management (5%)	$803,245
Construction Management (2.5%)	$401,622
Escalation (8%)	$1,285,192
Contingency (10%)	$1,606,489
	$5,703,038

Capital & Operating Cost Evaluation for SO2 Scrubber for No. 4 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,606	Permitted Capacity
Total Capital Investment (TCI)	**$21,800,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cost (CRC)	***$1,756,784***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Costs	$327,000	C = Based 0.015 TCI, per May 2021 FGD control cost manual
Caustic Costs†	$1,688,129	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$372,757	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,416 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$1,050,998	F = E × Electricity Cost
Fresh Water	$52,562	G = Freshwater use * water cost
Water Disposal	$4,304	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$3,513,352***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$206,761	H = 60% × (A + B + C + D)
Property Tax		I = 1% × TCI
Insurance		J = 1% × TCI
Administrative Charges		K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$206,761***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$5,476,896**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	924	
SO_2 Removed (tpy)	831	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$6,587**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. During this timeframe, the monthly values have varied from $460/ton to $920/ton.

ATTACHMENT 2
REFERENCE INFORMATION FOR RECOVERY FURNACES

Foley SO2 Mitigation

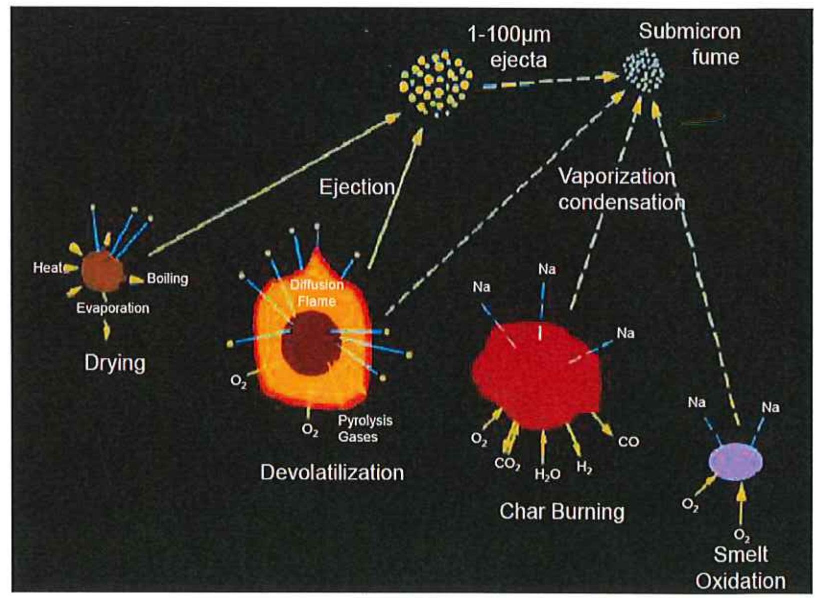
Georgia-Pacific
Packaging & Cellulose

Recovery Boiler SO2 Emissions 101

How is it formed

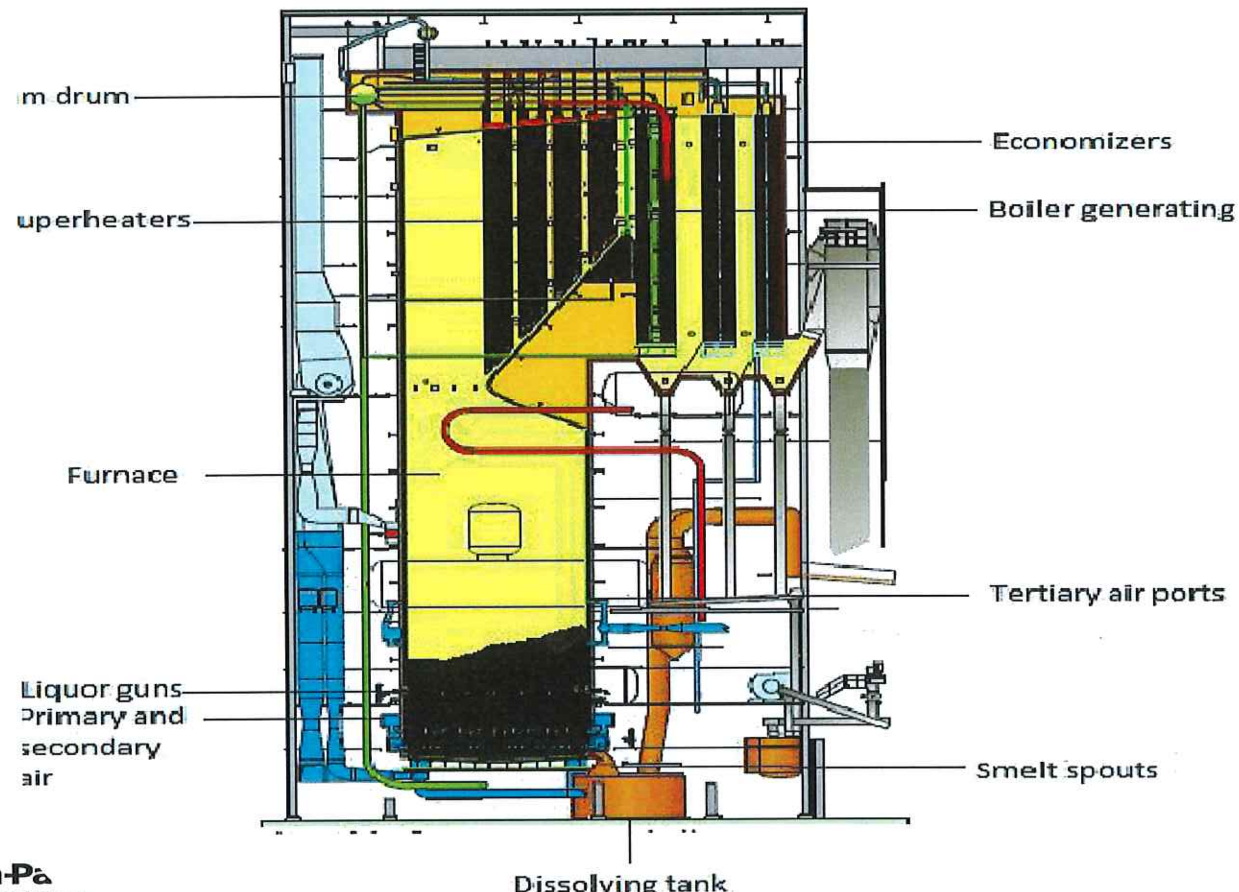
- SO2 is formed from sulfur in the Black Liquor
- Sulfur is released during combustion
- Sulfur capture is determined by
  - Hearth Temperature
  - Sodium Fuming
- High Bed Temperatures drive greater sulfur capture
- Higher Solids firing liquor results in higher bed temperature
- Air Distribution is essential to stage combustion and drive sulfur to the smelt

Black Liquor Combustion and Fume Formation



Georgia-Pacific
Packaging & Cellulose

Kraft Recovery Boiler – Terminology



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Levers to Affect SO2 Emissions in a Recovery Boiler

- Increasing Firing Solids
  - The #5 BLE that was installed in 2017 was designed to produce 70% solids which matches the capability of the existing recovery furnaces
  - Modern recovery boilers operate closer to 75%+ solids which lowers SO2 generation
    - Increasing the Solids on the recovery boilers is not practical above 72% due to the limitations on the firing system, liquor heater system and storage capabilities
    - With increased firing solids the heat input to the lower furnace exceeds the mechanical design of the lower furnace which could result in premature failure of the lower furnace tubes

- Air Systems
  - Modern air systems distribute air at three levels to ensure sulfur is sequestered in the smelt and not released in the fume
  - Foley Recovery furnaces are not this design

Levers for Lower SO2 Conditions

- High Furnace Loading
  - The higher the loading on the boiler the lower the SO2 emissions
  - This is because the bed temperature increases which causes the sequestration of sulfur
  - Furnace Design Consideration
    - #2 and #3 Recovery Furnaces have what is considered a "short" furnace design which was common for their vintage as direct contact design recovery boilers
    - This short furnace causes there to be a low residence time over the nose arch of the furnace
    - Short residence time means that you are limited in the amount of sodium fume that is available to capture sulfur in the lower furnace
    - As you increase the furnace load/temperature the boiler will carryover plugging the boiler reducing its capability to operate at a sustainable rate increasing SO2 emissions

Questions ?

Georgia-Pacific
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7.8.3 Foley Mill Four-Factor Analysis

G-P Cellulose/Foley Cellulose LLC owns and operates a softwood Kraft pulp mill (referred to as the "Foley Mill") located in Perry, Taylor County, Florida that manufactures bleached market, fluff, and specialty dissolving cellulose pulp. The Foley 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. 1230001-106-AV), most recently issued by the Department on March 22, 2022.

Pursuant to EPA's Regional Haze requirements in 40 CFR 51.308, the Department sent a letter to the Foley Mill on June 22, 2020, requesting a four-factor analysis for SO_2 emissions from following existing units:

- Power Boiler No. 1 (EU-002);
- Bark Boilers No. 1 (EU-004) and No. 2 (EU-019); and
- Recovery Furnaces No. 2 (EU-006), No. 3 (EU-007), and No. 4 (EU-0011).

Note that Power Boiler No. 2 was not requested because it is now permitted to fire only natural gas and annual SO_2 emissions are much less than five tons/year. The table below shows only those sources of SO_2 emissions at the facility that have been greater than 5 tons/year of SO_2 emissions during the last ten years.

In March of 2021, the Department sent a Request for Additional Information primarily concerning SO_2 emissions from the recovery furnaces. A part of the request focused on comparing SO_2 from the Foley Mill with other Florida mills. Based on the factor of "SO_2 emissions per ton of black liquor fired", the Foley Mill recovery furnaces were much less efficient at recovering the "smelt" (sodium carbonate and sodium sulfide) needed for the Kraft pulping process. This means that additional chemicals must be purchased to replace the loss constituents. There were several discussions with the Foley Mill who agreed to certify the existing SO_2 CEMS for the recovery furnaces by conducting Relative Accuracy Test Assessments (RATAs) and explore operational changes for the recovery furnaces that could reduce SO_2 emissions, resubmit the four-factor analysis for the recovery furnaces, reduce the maximum sulfur content for fuels, and cap SO_2 emissions.

Although the existing SO_2 CEMS for the recovery furnaces were not considered "regulatory" CEMS, they were used for process feedback and reporting emissions. After conducting the RATAs, the Foley also Mill identified two issues that required resolution to ensure the accuracy of recorded data. Specifically, it was determined that the span values and relative accuracy of the CEMS were not acceptable. These issues were resolved in August of 2021 and data collected since then are believed to be accurate. Based on this study, the Foley Mill developed SO_2 emissions factors for the three recovery furnaces:

- No. 2 Recovery Furnace: 0.359 lb/MMBtu
- No. 3 Recovery Furnace: 0.714 lb/MMBtu
- No. 4 Recovery Furnace: 0.421lb/MMBtu

The Foley Mill believes the wide range of SO_2 emissions factors to be the result of the inherent design and age of each furnace. Since corrected SO_2 emissions were much greater than previously reported, the Foley Mill also submitted an air quality analysis that demonstrated compliance with the 1-hour SO_2 NAAQS based on actual emissions.

The Foley Mill submitted a revised four-factor analysis to the Department on October 20, 2020. An updated analysis was submitted on August 30, 2022. On September 20, 2022, representatives from the Department met at the Foley Mill to discuss the four-factor analysis, cost data, guidance from the EPA cost control manual, and, specifically, the inherent design of the recovery furnaces as well as potential operational improvements to reduce SO_2 emissions. On November 16, 2022, the Foley Mill submitted a final revised four-factor analysis for the recovery furnaces.

The following table shows the annual SO_2 emissions for the emissions units included in the latest four-factor analysis, including the corrected emissions from the recovery furnaces.

Table A. Actual SO_2 Emissions (Tons/Year), 2012 – 2021 Based on AORs

Year	Total	PB No. 1	BB No. 1	RF No. 2	RF No. 3	RF No. 4	BB No. 2
2012	3896.4	15.2	730.9	785.8	1206.9	1143.5	14.1
2013	4010.1	23.7	728.8	805.6	1195.7	1242.5	13.8
2014	3848.9	32.1	902.2	693.3	1095.7	1092.2	33.4
2015	4072.5	52.5	863.6	721.2	1239.0	1183.1	13.1
2016	4050.4	105.9	677.1	790.2	1248.5	1143.2	85.4
2017	3145.4	60.2	192.4	698.0	1277.0	914.0	3.8
2018	3023.4	114.0	175.8	624.0	1087.0	1020.0	2.6
2019	2891.6	69.8	195.3	650.8	1135.5	837.4	2.8
2020	2310.1	29.3	155.2	332.1	948.4	842.6	2.5
2021	2767.6	49.0	172.5	627.2	1056.8	859.1	3.1

7.8.3.1 Power Boiler No. 1 (EU-002)

This unit is capable of producing 195,000 lb/hour of steam firing variety of fuels including natural gas, No. 6 fuel oil, on-specification used oil, and onsite/offsite-generated tall oil. The exhaust flue shares a common stack along with Power Boiler No. 2 and Bark Boilers Nos. 1 and 2. The boiler was designed by Babcock & Wilcox Company and constructed in 1953.

The liquid fuels share a common storage tank. The current Title V permit allows a maximum fuel sulfur content of 2.5% by weight for No. 6 fuel oil and tall oil. Note that the sulfur content of the facility-generated tall oil is typically 0.065 to 0.08% by weight as determined by a 2003 composite sample.

The boiler also serves as a backup control system for Bark Boiler No. 1 to combust low-volume, high-concentration non-condensable gases (LVHC-NCG) from the Pulping System (EU 046) for up to 2800 hours per year. In accordance with the current Title V permit, the LVHC-NCG gas are collected and routed to a TRS pre-scrubber prior to entering either boiler to control total reduced sulfur (TRS) compounds. The TRS pre-scrubber is required to remove 50% of the TRS compounds from the LVHC-NCG.

Between 2016 and 2021, Power Boiler No. 1 fired no fuel oil, but averaged 65.5 tons per year. The Department assumes the SO_2 emissions are primarily from firing LVHC-NCG as a backup control device. The Foley Mill identified a wet scrubber, a dry sorbent injection system, and low sulfur fuels along with good operating practices as available and feasible controls.

7.8.3.1.1 Estimated Cost of Compliance

The following table summarizes the general costs for the analyses provided.

Table B. General Costs for Supporting Data

Supporting Data for Control Device Cost Effectiveness Calculations

Parameter	Value		Note(s)
Operating Labor Cost	30.68	$/hr	1
Maintenance Labor Cost	32.15	$/hr	1
Caustic Cost	480	$/ton	1
Electricity Cost	0.0755	$/kWh	1
Water Cost	0.86	$/Mgal	2
Wastewater Treatment Cost	0.64	$/Mgal	1

1. Labor, caustic, electricity, and wastewater based on Foley specific data.
2. Water cost based on data from similar facilities.

Chemical, Energy, Water Use Basis

Amount of NaOH per SO2, based on molar ratio		1.25	lb/lb SO2 Removed	
NaOH solution, 50%		2.5	lb/lb SO2 Removed	
Data for Recovery Furnace				
Electricty per AFPA data		440.92	kW/MMlb BLS	
Freshwater use per AFPA Data		40.00	gpm/(MMlb BLS/day)	
Wastewater disposal per AFPA Data		4.00	gpm/(MMlb BLS/day)	
Data for Boiler	Reference is		420,000	acfm
Electricity per previous BART Control data		0.00175	KWhr/acfm	
Freshwater use per previous BART Data		0.233	Mgal/acfm	
Wastewater disposal per Previous BART data		0.082	Mgal/acfm	

1. Caustic use based on 2NaOH + SO2 → Na2SO3 + H2O
2. Usage of electricity, water, and waste based on reference cost estimates for controls.
   AFPA data basis is http://www.nescaum.org/documents/bart-resource-guide/be-k-capital-operating-cost-estimate-9-20-01.pdf/
   Previous BART Data is based on a 2008 BART control submittal for a similar GP unit.

<u>Wet Scrubber</u>

The Foley Mill used a recent cost estimate developed in 2020 for a wet scrubber to control exhaust from a lime kiln at a facility in Oregon. This cost estimate was adjusted for the Power Boiler No. 1 by ratioing the flow rates to the 0.6 power (an engineering estimating technique known as the Rule of Six Tenths). Caustic use was based on the molar ratio of sodium hydroxide to SO_2 emitted as well as an assumed 10% loss. Electricity requirements, water use, and waste generation costs were based on a detailed vendor quote for a similar system at a facility in Georgia. These usage rates were scaled again based on air flow rates. Facility costs for labor, water, waste, and caustic were based on the Mill's site-specific data or data from other similar facilities as identified in the above table for general costs. Capital costs were annualized based on a 30-year life span and 5% interest rate as outlined in EPA's *DRAFT EPA SO_2 and Acid Gas Control Cost Manual.* The actual SO_2 emissions were estimated based on an average of 81.35 tons/year (2015 – 2019) and a wet scrubber removal efficiency of 98%.

A table summarizing the capital, operating, and estimated cost-effectiveness to install and operate a wet scrubber is provided on the following page. Based on this analysis, a total capital investment of almost $7 million and the accompanying annual operating costs result in an estimated cost effectiveness of $13,547/ton to reduce actual SO_2 emissions by approximately 80 tons. The Department agrees that this level is not cost effective for this regional haze analysis.

<u>Dry Sorbent Injection System</u>

The Foley Mill also estimated the capital cost for a system to inject milled trona using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract. Facility labor, chemical, and utility costs were used to estimate the capital and annualized costs 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. Approximately 73 tons/year of actual SO_2 emissions could be removed based on an average of 81.3 tons of SO_2/year (2015 – 2019) and a removal efficiency of 90%. The capital recovery factor for annualizing the capital costs was based on 5% interest and 30-year life for boiler.

Table C. Estimated Costs for a Wet Scrubber Installed on Power Boiler No. 1

Capital & Operating Cost Evaluation for SO2 Scrubber for PB1

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$7,200,000	Based on 2020 cost estimate for Lime Kiln for similar 4-factor Analysis
Vendor Quoted System (cfm) =	124,500	
CFM analyzed	115,770	
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$6,892,686**	Prorated from previous vendor quote based on capacity ratio raised to the power of
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Contr
Capital Recovery Cost (CRC)	***$448,714***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$105,230	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	202	Power (kWh) ratioed based on similar boiler cost estimate values.
Cost of Electricity Usage	$133,793	F = E × Electricity Cost
Fresh Water	$23,199	G = Freshwater use * water cost
Water Disposal	$6,065	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$322,808***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$68,927	I = 1% × TCI
Insurance	$68,927	J = 1% × TCI
Administrative Charges	$137,854	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$308,420***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$1,079,942**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	81.35	
SO_2 Removed (tpy)	79.72	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$13,547**	**$/ton = AC / Pollutant Removed**

1. TCI per 2020 Envitech estimate for 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.

Table D. Estimated Costs for a Dry Sorbent Injection Installed on Power Boiler No. 1

Foley PB1

Capital and Annual Costs Associated with Trona Injection

Variable	Designation	Units	Value	Calculation
Heat Input		**MMBtu/hr**	**151.3**	
Unit Size	A	MW	13	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	0.124	Based on 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	1.51E+08	151.33 MMBtu/hr
NSR	K	-	2.61	Milled Trona w/ FF = 0.208e^(0.0281*H)
Sorbent Feed Rate	M	ton/hr	0.20	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	0.16	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	0.00	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV; fires primarily natural gas, set to zero.
Aux Power	Q	%	0.30	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	100	Default value for disposal without fly ash
Aux Power Cost	T	$/kWh	0.06	Default value in report
Operating Labor Rate	U	$/hr	49.09	Typical labor cost, includes 60% overhead cost

SO_2 Control Efficiency:	**90%**
Representative Emissions	**81.3**
Controlled SO_2 Emissions:	**73.2**

Capital Costs					
Direct Costs					
BM (Base Module) scaled to 2019 dollars		$	$	5,864,531	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	586,453	10% BM
Labor adjustment	A2	$	$	293,227	5% BM
Contractor profit and fees	A3	$	$	293,227	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	7,037,438	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	351,872	5% CEC
Total project cost w/out AFUDC	TPC	$	$	7,389,309	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$**	**7,389,309**	**CECC+B1+B2**

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	204,206	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	58,645	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	6,830	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**269,681**	**FOMO+FOMM+FOMA**
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	292,753	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	138,202	(N+P)*S
Additional auxiliary power required	VOMP	$	$	113,801	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**544,756**	**VOMR+VOMW+VOMP**
Indirect Annual Costs					
General and Administrative		2%	of TCI	$	147,786
Property Tax		1%	of TCI	$	73,893
Insurance		1%	of TCI	$	73,893
Capital Recovery		6.51%	x TCI	$	480,685
Total Indirect Annual Costs				**$**	**776,258**
Life of the Control:		30 years		5.00% interest	
Total Annual Costs				**$**	**1,590,695**
Total Annual Costs/SO_2 Emissions				**$**	**21,727**

[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.

Based on this analysis, a total capital investment of more than $7 million to install a dry sorbent injection system and the accompanying operating costs result in an annualized cost effectiveness of $21,727/ton to reduce actual SO_2 emissions by approximately 73 tons/year. The Department agrees that this level is not cost effective for this regional haze analysis.

<u>Low Sulfur Fuel and Good Operating Practices</u>

The Foley Mill proposed to:

- Reduce the maximum sulfur content of No. 6 fuel oil from 2.5% to 1.02% by weight.
- Cap No. 6 fuel oil use to 3,500,000 gallons/year for the combination of Power Boiler No. 1 and Bark Boilers Nos. 1 and 2, excluding usage necessitated by any natural gas curtailment.

The Department notes that setting a maximum fuel sulfur specification of 1.02% by weight will likely result in fuel purchases well below 1% sulfur. The Department will not impose the multi-unit fuel cap because this level is much higher than actual fuel oil use for these units in each of the last ten years. Instead, the Regional Haze air construction permit requires the use of natural gas except for periods of natural gas curtailments, pipeline disruptions, and physical mill problems that otherwise prevent the firing of natural gas in Power Boiler No. 1.

7.8.3.1.2 Time Necessary for Compliance

Since Power Boiler No. 1 has fired only natural gas during that last six years, this could be implemented immediately. The reduction in maximum fuel sulfur could be implemented for future purchases.

7.8.3.1.3 Energy and Non-Air Quality Impacts of Compliance

There are no energy or non-air quality impacts associated with these specifications and work practices.

7.8.3.1.4 Remaining Useful Life

Power Boiler No. 1 was assumed to have a remaining useful life of 30 years or more.

7.8.3.1.5 Summary of Findings for No. 1 Power Boiler

Again, Power Boiler No. 1 has not fired No. 6 fuel oil since 2015. The SO_2 emissions reported since 2016 are likely from periods when this unit is used as the backup control for combusting LVHC-NCG from the Pulping System. The Regional Haze air construction permit:

- Power Boiler No. 1 shall fire only natural gas except for periods of natural gas curtailment, pipeline disruptions, or physical mill problems that otherwise prevent the firing of natural gas in this unit. When necessary, liquid fuels from the common tank may be fired during these exceptional periods.
- For future additions of No. 6 fuel oil and tall oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel delivery receipts and/or sampling and analysis.

7.8.3.2 Bark Boiler No. 1 (EU004)

Bark Boiler No. 1 is capable of producing 200,000 lb/hour of steam while firing a variety of fuels including wood materials (bark, chips, sawdust, etc.), natural gas, No. 6 fuel oil, facility generated on-specification used oil, and onsite/offsite-generated tall oil. The exhaust flue shares a common stack along with Power Boiler Nos. 1 and 2 and Bark Boiler No. 2.

Particulate matter emissions are controlled by a cyclone collector and a wet venturi scrubber. Particles collected by the cyclone collector are recirculated back to the boiler. Although some control of SO_2 emissions results from absorption onto fly ash and particle removal through the wet venturi scrubber, caustic is also added to the wet scrubbing media adjust the pH level to further control SO_2 emissions. Following the scrubber is a chevron type demister to trap and remove entrained water droplets.

Bark Boiler No. 1 is the primary control device for combusting LVHC-NCG from the Pulping System (EU 046). The LVHC-NCG are collected and routed through the spray nozzle-type TRS pre-scrubber prior to this boiler for destruction. As previously described, Power Boiler No. 1 is used as the backup control system for the Pulping System (EU 046).

Over the last five years, SO_2 emissions have averaged about 178 tons/year. Since the annual average No. fuel oil firing rate has been less than 1000 gallons per year, most of the SO_2 emissions are likely from combusting LVHC-NCG from the Pulping System (EU 046). For the similarly sized Power Boiler No. 1, total capital investment of more than \$7 million to install a new wet scrubber (\$13,547/ton) or dry sorbent injection (\$21,700/ton) and the accompanying operating costs even at twice the emissions reductions are not cost effective for this regional haze analysis. However, the Foley Mill did propose operational changes to the existing wet scrubber to increase caustic to the existing wet scrubber to maintain the pH level as an available and feasible control.

7.8.3.2.1 Estimated Costs of Compliance

Increasing caustic to the wet scrubber to maintain the pH level at 8.0 for SO_2 control also requires addition of an antiscalant to minimize fouling and scaling due to caustic buildup in the boiler. The Foley Mill used current caustic and antiscalant costs with the molar ratio of sodium hydroxide to SO_2 emissions to estimate the costs. The achievable control efficiency for this change was estimated to be approximately 51% reduction from the average SO_2 emissions of 188 tons/year (2017 – 2019).

Operating Cost Evaluation for SO2 Caustic Addition for BB1

Emission Rate with Caustic (lb/ADTUBP)	1.74	
Emission Rate without Caustic and with Pre-scrubber (lb/ADTUBP)	3.54	
% Control - caustic	51%	
Caustic Use	2.5	lb NaOH per lb SO2 removed
Caustic Loss	10%	
Caustic Cost	480	\$/ton Caustic
Anti-scaler	\$125,000	per year
Cost per ton of SO_2 removed, Caustic	\$1,320	\$/ton
Cost per ton of SO_2 removed, Anti-Scaler	\$1,307	\$/ton
Total tons reduced	96	tons
Total cost per ton	\$2,627	

1. Emissions rates based on stack test data and % control represents improvement over operation with pre-scrubber.
2. Caustic use based on molar ratio.
3. Anti-scaler based on estimated cost of using caustic full time and improved caustic control.

This operational change results in an estimated annualized cost effectiveness of \$2627/ton to remove 96 tons/year and is cost effective for this regional haze analysis.

7.8.3.2.2 Time Necessary for Compliance

The Foley Mill currently adds weak wash to the existing wet scrubber media as an SO_2 control measure under a Title V Compliance Assurance Monitoring Plan. The proposed reduction in fuel sulfur could be implemented for all future purchases.

7.8.3.2.3 Energy and Non-Air Quality Impacts of Compliance

The existing wet scrubber would continue to operate in the same general manner without any significant energy or non-air quality impacts for implementing this control measure.

7.8.3.2.4 Remaining Useful Life

Bark Boiler No. 1 was assumed to have a remaining useful life of 30 years or more.

7.8.3.2.5 Summary of Findings for Bark Boiler No. 1

The Regional Haze air construction permit requires the:

- Bark Boiler No. 1 shall fire only wood materials and natural gas except for periods of natural gas curtailment, pipeline disruptions, or physical mill problems that otherwise prevent the firing of natural gas in this unit. When necessary, liquid fuels from the common tank may be fired during these exceptional periods.
- For future additions of No. 6 fuel oil and tall oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel delivery receipts and/or sampling and analysis.
- Wet Venturi Scrubber. Prior to combustion in Bark Boiler No. 1, LVHC-NCG shall be directed through the TRS pre-scrubber. At all times that LVHC-NCG or No. 6 fuel oil is fired, caustic or weak wash shall be added to the wet venturi scrubbing media to maintain a pH level of at least 8.0 (3-hour block average) and a wet scrubber flow rate of 1000 gpm (3-hour block average) for the control of SO_2 emissions. The permit specifies the parametric monitoring frequency and requirements.

7.8.3.3 Bark Boiler No. 2 (EU-019)

Bark Boiler No. 2 is capable of producing 395,000 lb/hour of steam and fires a variety of wood materials (bark, chips, sawdust, etc.) natural gas, No. 6 fuel oil, facility-generated on-specification used oil, and onsite/offsite-generated tall oil. Flue gases are split into two streams. One stream flows through the economizer, wet venturi scrubber, demister and then out the stack. The other stream bypasses the economizer and goes directly to a cyclone collector and second wet venturi scrubber. Both scrubbers utilize water as the scrubbing media. Collected particulate is re-injected into the boiler. The bark boiler commenced operation in 1954.

From 2017 through 2021, the Foley Mill fired primarily natural gas along with wood materials, which maintained SO_2 emissions below 5 tons/year. For SO_2 emissions below 5 tons/year, there are no add-on controls that are cost effective. Therefore, the only available and feasible options are to optimize the firing of natural gas with wood materials and reducing liquid fuel sulfur from 2.5% to 1.02% by weight. However, should the facility return to firing fuel oil, caustic could be added to the existing wet scrubbers in a cost-effective manner.

7.8.3.3.1 Estimated Costs of Compliance

Bark Boiler No. 1 has not fired substantial amounts of No. 6 oil since 2016, when the unit began firing natural gas.

7.8.3.3.2 Time Necessary for Compliance

The Foley Mill could optimize the firing of natural gas with wood materials could be implemented immediately. The proposed reduction in fuel sulfur could be implemented for all future purchases. Should the facility return to firing significant amounts of fuel oil, the Foley

Mill would only need to purchase the additional caustic and other chemicals necessary to further control SO_2 emissions.

7.8.3.3.3 Energy and Non-Air Quality Impacts of Compliance

There would be no adverse energy or non-air quality impacts for implementing these control measures.

7.8.3.3.4 Remaining Useful Life

Bark Boiler No. 2 is assumed to have a remaining useful life of 30 years or more.

7.8.3.3.5 Summary of Findings for Bark Boiler No. 2

The Regional Haze air construction permit requires the following:

- Bark Boiler No. 2 shall fire only wood materials and natural gas except for periods of natural gas curtailment, pipeline disruptions, or physical mill problems that otherwise prevent the firing of natural gas in this unit. When necessary, liquid fuels from the common tank may be fired during these exceptional periods.
- For future additions of No. 6 fuel oil and tall oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel delivery receipts and/or sampling and analysis.

7.8.3.4 Recovery Furnaces Nos. 2, 3, and 4 (EU006, EU007, EU011)

Recovery Furnace No. 2 is a low-odor, non-direct contact evaporator unit that produces a nominal 380,000 lb/hour of steam by firing black liquor. The furnace was originally constructed by Babcock & Wilcox in 1957 as a direct-contact evaporator design recovery furnace and later modified. Particulate matter emissions are controlled by an electrostatic precipitator. The exhaust stack is equipped with a CEMS to continuously monitor CO, NOx, SO_2 and TRS. Opacity is continuously monitored by a COMS.

Recovery Furnace No. 3 is a low-odor non-direct contact evaporator unit that produces approximately 325,000 lb/hour of steam by firing black liquor. The furnace was originally constructed by Combustion Engineering in 1964 as a direct-contact evaporator design recovery furnace. Particulate matter emissions are controlled by an electrostatic precipitator. The exhaust stack is equipped with a CEMS to continuously monitor CO, NOx, SO_2 and TRS. Opacity is continuously monitored by a COMS.

Recovery Furnace No. 4 is a low-odor non-direct contact evaporator unit that produces approximately 450,000 lb/hour of steam by firing black liquor. The furnace was originally constructed by Babcock & Wilcox in 1973 with a membrane wall construction to minimize air in-leakage. Particulate matter emissions are controlled by an electrostatic precipitator. The exhaust stack is equipped with a CEMS to continuously monitor SO_2 and TRS. Opacity is continuously monitored by a COMS.

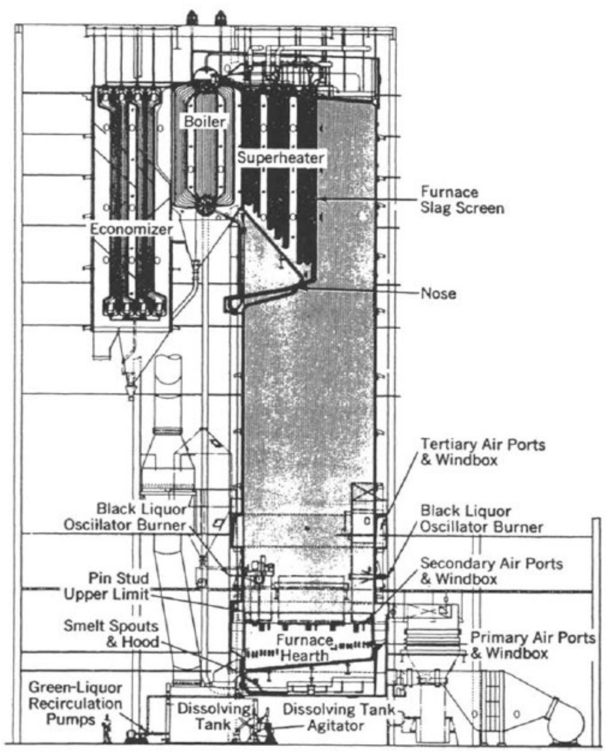
In addition to black liquor with a solids content of approximately 70%, each boiler is authorized to fire the following fuels for startup, shutdown, and as a supplemental fuel to maintain flame stability in the furnace.

- No. 6 fuel oil with a maximum sulfur content of 2.5% by weight;

- Onsite or offsite-generated tall oil with a maximum sulfur content of 2.5% by weight;
- On-specification used oil that meets the applicable requirements of 40 CFR 279;
- Natural gas; and
- Ultra-low sulfur distillate oil.

Recovery furnaces fire black liquor, which contains lignin (solids) from previously processed wood. This process recovers inorganic chemicals as smelt (sodium carbonate and sodium sulfide), combusts the organic chemicals so they are not discharged as pollutants, and recovers the heat of combustion in the form of steam. Particles captured in the furnace exhaust by the electrostatic precipitator also contain sodium carbonate and sodium sulfide and are returned to the recovery furnace. The chemicals recovered in the smelt are dissolved in water to make green liquor which is typically reacted with lime to regenerate white liquor. White liquor is used in the pulping process to separate lignin and hemicellulose from the cellulose fiber in wood chips for the production of pulp. Inefficient recovery furnaces require the purchase of raw materials to make up for the lost chemicals.

Sulfur dioxide forms during combustion when some of the sulfur in the black liquor is oxidized. High bed temperatures cause sodium fuming which retains sulfur in the bed. A higher solids content and firing rate of black liquor generates higher bed temperatures. A higher solids content can be achieved by increasing capacity of evaporator equipment. Proper air distribution will also drive sulfur to the smelt reducing SO_2 emissions. Fuels containing sulfur may also generate SO_2 emissions.



Although modern recovery furnaces operate with a black liquor solids content of 75% or more which reduces the generation of SO_2 emissions, the three existing recovery furnaces were designed for a maximum solids content of only 70% solids. Modern furnaces also employ air systems that distribute air at three levels to ensure sulfur is driven to the smelt and not released in the fume. The existing units at the Foley Mill do not have this air distribution system.

In 2017, the Foley Mill installed the No. 5 black liquor evaporator designed to produce 70% solids and match requirements of the existing recovery furnaces. Increasing the solids content above about 72% is not practical and results in issues with the current firing system, liquor heater system, and existing storage capacities. Also, constructed in the 1950’s, increasing the firing rate and temperatures to the existing recovery furnaces can exceed the mechanical design of the lower furnace and result in premature failure of the lower furnace tubes.

Other design limitations for Recovery Furnaces Nos. 2 and 3 are the "short" furnace design that is a common design for this vintage of direct-contact furnaces, despite the modifications to non-direct contact evaporator units. A short furnace design results in a low residence time over the nose arch of the furnace. This means that there is less contact time with sodium fumes that capture the sulfur in the lower furnace. As the black liquor rate and bed temperature increases, carryover will plug the furnace reducing the capability to sustain operation at a given rate and increasing SO_2 emissions.

The Department requested the Foley Mill to considering improving operational characteristics that may, on their own or in combination, help reduce SO_2 emissions and increase recovery efficiency such as boiler design, increasing the solids content for black liquor to increase the bed temperature, sulfidity (sulfur-to-sodium ratio), air distribution and stack oxygen content, etc. Typically, SO_2 emissions from recovery furnaces are minimized by equipment design and operational considerations.

Essentially, the Foley Mill ruled out such changes concluding that the existing recovery furnaces are physically limited by the inherent "short" furnace design, original metals used from the 1950's , designed metal thickness, etc. For example, attempting to increase the narrow nose arch could increase the exhaust retention time but also cause more fouling. More fouling requires more shutdowns to conduct washes which add thermal stress cycles to the unit. For recovery furnaces, safety is a critical concern when considering major physical changes to such vintage units because the combination of molten smelt and large quantities of water in the heat exchanger tubes make these furnaces potentially explosive, a critical concern at all times.

Foley consider the list of common flue gas desulfurization systems: spray dryer absorbers, dry sorbent injection, and conventional wet scrubbers. Each of the recovery furnaces currently use electrostatic precipitators to control particulate matter, which is common in the industry. To be cost effective, the spray dryer absorber and dry sorbent injection systems would inject caustic materials upstream of the ESP to neutralize sulfur dioxide and remove the resulting solids formed as well as any excess caustic materials. However, this would contaminate and adversely impact the recovery process such that these systems are not considered feasible for recovery furnaces. The Foley Mill evaluated a wet scrubber installed after the ESP for each existing unit as described in a revised four-factor analysis submitted November 16, 2022 with the following changes:

- A unit-specific wet scrubber capital cost was provided by an equipment vendor for each recovery furnace that reflects its size and configuration.
- The property tax, insurance, and administrative costs were removed from the analysis.
- Capital recovery factor was updated to reflect an interest rate of 7% and a 30-year life.
- Maintenance costs were updated to reflect the most recent control cost manual guidance and confirmed with internal engineering resources.
- Material costs were updated with the most current data.

7.8.3.4.1 Estimated Costs of Compliance - Recovery Furnaces Nos. 2, 3, and 4

For each recovery furnace, the following tables summarize the total capital investment, the annualized capital and operating costs, and the cost-effectiveness in terms of dollars per ton of SO_2 removed.

Wet Scrubber

Total Capital Investment (TCI) - No. 2 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$22,000,000**
Equipment	
Andrtiz SO2 Scrubber Package	$5,735,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$544,800
	$7,354,800
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$525,000
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,250,000
	$7,825,000
Balance of Plant (7%}	**$1,062,586**
Project Costs	
Engineering (10%)	$1,624,239
Project Management (5%)	$812,119
Construction Management (2.5%)	$406,060
Escalation (8%)	$1,299,391
Contingency (10%)	$1,624,239
	$5,766,047

Capital & OperatingCost Evaluation for 502 Scrubber for No. 2 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,171	Permitted Capacity
Total Capital Investment (TCI)	$22,000,000	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF)	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cost {CRC}	*$1,772,901*	*CRC= TC/ x CRF*
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A= Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Costs	$330,000	C = Based 0.015 TCI, per May 2021FGD control cost manual
Caustic Costst	$1,201,657	E = Mass of NaOH to neutralize 502 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$265,339	E = Mass of H2504to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,033 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$766,504	F = E x Electricity Cost
Fresh Water	$38,334	G= Freshwater use • water cost
Water Disposal	$3,139	H = Water disposal amount• disposal cost
Total Direct Operating Costs (DOC)	*$2,622,575*	*DOC=A + B+ C+ D +E+ F+ G+H*
Indirect Operating Costs {IOC)		
Overhead	$208,561	H = 60% x (A+ B + C+ D)
Property Tax		I= 1%xTCI
Insurance		J= 1% xTCI
Administrative Charges		K=2%xTCI
Total Indirect Operating Costs (JOC)	*$208,561*	*IOC=H+ /+J+K*
Total Annualized Cost (AC)=	$4,604,037	*AC= CRC+ DOC+ IOC*
50_2 Uncontrolled Emissions (tpy)	657.59	
50_2 Removed (tpy)	591.83	90% Removal Efficiency
Cost per ton of 502 Removed ($/ton)	$7,779	$/ton= AC/ Pollutant Removed

• U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 50_2 and Acid Gas Controls.

t Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. Duringthis timeframe, the monthly values have varied from $460/ton to $920/ton.

Total Capital Investment (TCI} - No. 3 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$20,500,000**
Equipment	
Andrtiz SO2 Scrubber Package	$4,998,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$485,840
	$6,558,840
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$505,200
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,052,000
	$7,607,200
Balance of Plant (7%}	**$991,623**
Project Costs	
Engineering (10%)	$1,515,766
Project Management (5%)	$757,883
Construction Management (2.5%)	$378,942
Escalation (8%)	$1,212,613
Contingency (10%)	$1,515,766
	$5,380,970

Capital & Operating Cost Evaluation for S02 Scrubber for No. 3 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	988	Permitted Capacity
Total Capital Investment (TCI)	$20,500,000	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF)	0.0806	CRF = 7% interest and 30-yr equipment life
Capitol Recovery Cost {CRC)	***$1,652,021***	*CRC= TC/ x CRF*
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A= Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15%*of* operating labor
Maintenance Costs	$307,500	C= Based 0.015 TCI, per May 2021FGD control cost manual
Caustic Costst	$2,131,633	E= Mass of NaOH to neutralize S02 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$470,687	E= Mass of H2504 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	871 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$646,738	F= E x Electricity Cost
Fresh Water	$32,344	G= Freshwater use • water cost
Water Disposal	$2,648	H = Water disposal amount• disposal cost
Toto/ Direct Operating Costs /DOC)	*$3,609,153*	*DOC=A + B+ C+D +E+ F+ G+ H*
Indirect Operating Costs /JOC)		
Overhead	$195,061	H = 60% x (A+ B + C+ D)
Property Tax		I= 1%xTCI
Insurance		J = 1% xTCI
Administrative Charges		K= 2% xTCI
Toto/ Indirect Operating Costs (JDC)	*$195,061*	*JDC= H+ /+J+ K*
Total Annualized Cost (AC) =	$5,456,235	*AC= CRC+ DOC+ /DC*
50_2 Uncontrolled Emissions (tpy)	1,167	
$S0_2$ Removed (tpy)	1,050	90% Removal Efficiency
Cost per ton of S02 Removed ($/ton)	$5,197	$/ton= AC/ Pollutant Removed

- U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section S 50_2 and Acid Gas Controls.

t Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. Duringthistimeframe, the monthly values have varied from $460/ton to $920/ton.

Total Capital Investment (TCI) - No. 4 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$21,800,000**
Equipment	
Andrtiz 502 Scrubber Package	$5,614,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$535,120
	$7,224,120
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$521,800
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,218,000
	$7,789,800
Balance of Plant (7%)	**$1,050,974**
Project Costs	
Engineering (10%)	$1,606,489
Project Management (5%)	$803,245
Construction Management (2.5%)	$401,622
Escalation (8%)	$1,285,192
Contingency (10%)	$1,606,489
	$5,703,038

Capital & Operating Cost Evaluation for SO2 Scrubber for No. 4 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,606	Permitted Capacity
Total Capital Investment (TCI)	$21,800,000	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF)	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cast (CRC)	*$1,756,784*	*CRC= TC/" CRF*
Operating Costs		
Direct Operating Costs(DOC)		
Operating Labor	$15,306	A= Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B= 15% of operating labor
Maintenance Costs	$327,000	C= Based 0.015 TCI, per May 2021 FGD control cost manual
Caustic Costst	$1,688,129	E= Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$372,757	E= Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,416 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$1,050,998	F= E x Electricity Cost
Fresh Water	$52,562	G= Freshwater use • water cost
Water Disposal	$4,304	H = Water disposal amount• disposal cost
Total Direct Operating Costs (DOC)	*$3,513,352*	*DOC=A + B+ C+ D+E+ F+ G+ H*
Indirect Operating Costs (IOC)		
Overhead	$206,761	H= 60% x (A+ B+ C+ D)
Property Tax		I= 1% xTCI
Insurance		J= 1% xTCI
Administrative Charges		K= 2%xTCI
Total Indirect Operating Costs {IOC}	*$206,761*	*IOC= H+ I+I+K*
Total Annualized Cost (AC)=	$5,476,896	*AC=CRC+ DOC+ IOC*
SO_2 Uncontrolled Emissions (tpy)	924	
SO_2 Removed (tpy)	831	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	$6,587	$/ton= AC/Pollutant Removed

• U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO, and Acid Gas Controls.

t Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. During this timeframe, the monthly values have varied from $460/ton to $920/ton.

The Department is unaware of any facility with a wet scrubber installed for SO_2 control on a recovery furnace. In its Second Regional Haze Plan (2018 – 2028), the Department of Ecology State of Washington State indicated, "The cost of installing a wet scrubber is not considered cost effective for any mill as the cost effectiveness values are in excess of $27,000/ton of pollutant removed. (We note that the estimated costs are less than those included in the 2016 Ecology RACT analysis and may be lower than the true cost needed to install such a control device.)" See page O-32 in Appendix O of the plan.

Based on the estimated high capital and operating costs, the Foley Mill does not consider the installation of a wet scrubber to be cost effective. After conducting a site visit, discussing the physical constraints, and reviewing the costs, the Department agrees that this option is not cost effective for this regional haze analysis. This leaves only the use of lower sulfur fuels and good operating practices as the only available, cost-effective measures.

7.8.3.4.2 Time Necessary for Compliance - Recovery Furnace Nos. 2, 3, and 4

The use of lower sulfur fuels and good operating practices can be implemented almost immediately.

7.8.3.4.3 Energy and Non-Air Quality Impacts of Compliance - Recovery Furnaces Nos. 2, 3, and 4

There are no energy or non-air quality impacts associated with the use of lower sulfur fuels and good operating practices.

7.8.3.4.4 Remaining Useful Life - Recovery Furnaces Nos. 2, 3, and 4

The analysis assumed a remaining useful life of at least 30 years for the recovery furnaces.

7.8.3.4.5 Summary of Findings - Recovery Furnaces Nos. 2, 3, and 4

The Foley Mill proposed reducing the maximum content of No. 6 fuel oil from 2.5% to 1.02% by weight and establishing an SO_2 emissions cap of 3325 tons per year for Recovery Furnaces Nos. 2, 3, and 4.

The Regional Haze air construction permit requires the following:

- For future additions of No. 6 fuel oil and tall oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel delivery receipts and/or sampling and analysis.
- The permittee shall continue to use, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) installed on each of the three recovery furnaces to measure and record SO_2 emissions. Each CEMS shall be certified to meet the quality assurance requirements of Appendix CEMS including conducting the required periodic Relative Accuracy Test Assessments (RATA). Each certified CEMS shall be used to determine the SO_2 emissions for payment of Title V annual fees.
- Combined SO_2 emissions from Recovery Furnace Nos. 2, 3 and 4 are capped at 3,200.0 tons per consecutive 12 months from 2024 through 2025. The cap decreases to 3000.0 tons per consecutive 12 months from 2026 through 2027. The cap decreases again to 2800.0 tons per consecutive 12 months beginning in 2028. Besides being representative of more recent SO_2 emissions, these graduated emissions caps allow time for the Foley Mill to develop improved operating techniques that improved chemical recovery while minimizing emissions.
- The permittee shall have an engineering study conducted by an independent professional engineer to evaluate the following parameters for each recovery furnace: liquor sulfidity, liquor solids content, bed temperature, stack oxygen content, furnace load, auxiliary fuel use, sodium salt fume in the upper furnace, furnace design, and SO_2 emissions. The study shall collect parametric operating data for at least 400 hours on each recovery furnace. Based on an analysis of the data collected, the study shall determine which parameters, and which combination of parameters, have the biggest impact on SO_2 emissions. The study shall recommend a set of parameters and appropriate operating ranges to minimize SO_2 emissions.