BIOMASS ONE LP

2350 Avenue G
White City, Oregon 97503
Office: 541-826-9422
Fax: 541-826-6186
www.biomassone.com

June 11, 2020

D Pei Wu
Air Quality Planning
Oregon Department of Environmental Quality
700 NE Multnomah St; Ste 600
Portland, OR 97232
wu.d@deq.state.or.us

RE: Regional Haze Four Factor Analysis
Biomass One, LP

Dear D Wu:

The attached report documents the results of a four-factor analysis conducted for Biomass One's White City, OR plant (Biomass One or "the plant"). This report is provided in response to the Oregon Department of Environmental Quality (DEQ) request letter provided to Biomass One in December 2019.

Statement of Certification

Based on information and belief formed after reasonable inquiry, the statements and information in this document and any attachments are true, accurate, and complete.

Gregory R. Blair, National Public Energy	President
Name of Responsible Official	**Title of Responsible Official**
Gregory R. Blair	6/12/2020
Signature of Responsible Official	**Date**

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at 541.826.9422.

Sincerely,

Kurt E. Lumpkin
Kurt Lumpkin
General Manager

Enclosure

cc: Ms. Janice Tacconi, Title V Permit Writer
ODEQ-Western Region

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Biomass One / White City, OR

Prepared By:

Aaron Day – Principal Consultant
Beth Ryder – Senior Consultant
Sam Najmolhoda – Associate Consultant

TRINITY CONSULTANTS
12725 SW Millikan Way
Suite 300
Beaverton, OR 97005
503.906.7833

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1. EXECUTIVE SUMMARY

This report documents the results of a four-factor analysis conducted for Biomass One's White City, OR plant (Biomass One or "the plant"). This report is provided in response to the Oregon Department of Environmental Quality (DEQ) request letter provided to Biomass One in December 2019.

Biomass One was not identified as an eligible facility for the best available retrofit technology (BART) program during the first round of regional haze as it was built after August 7, 1977. DEQ has identified the plant as an eligible source for the regional haze program reasonable progress analysis based on a screening process that considers both the quantity of emissions from the facility and the proximity to the Class I areas protected by the regional haze program.

The U.S. EPA's guidelines in 40 CFR Part 51.308 are used to evaluate control options for the plant. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these four factors are taken into consideration in selecting the goal (40 CFR 51. 308(d)(1)(i)(A)).

The purpose of this report is to provide information to DEQ regarding potential nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter less than 10 micrometers in diameter (PM_{10}) emission reduction options for the Biomass One plant. Based on the Regional Haze Rule, associated EPA guidance, and DEQ's request, Biomass One understands that DEQ will only move forward with requiring emission reductions from the plant if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

The report identifies several potential control technologies for the Biomass One Plant, as summarized in Table 1-1 below.

Table 1-1. Potential Control Technologies

Pollutant	Emission Unit	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reduction?	Notes
NO_X	North and South Boilers	Flue Gas Recirculation (FGR)	No	N/A	No	Thermal NO_X controls are not appropriate for the boilers, as sufficient temperatures for substantial thermal NO_X formation are not achieved in the boilers.
		Low Excess Air (LEA)	No	N/A	No	
		Low NO_x Burners (LNB)	No	N/A	No	NO_X emissions control methods for liquid and gaseous fuels are not applicable or effective for wood-fired boilers.
		Fuel Staging	No	N/A	No	
		Staged Combustion	Yes	Yes	Yes	The Biomass One boilers already use staged combustion for control of Fuel NO_X and other pollutants.
		Selective Catalytic Reduction (SCR)	Yes	No	No	In addition to technical concerns associated with high-dust SCR operation, the control is not cost effective.
		Selective Non-Catalytic Reduction (SNCR)	No	N/A	No	SNCR is technically infeasible due to temperatures outside the necessary range for ammonia or urea injection.
SO_2	No additional emissions reductions options were identified for SO_2 emissions from the North and South boilers.					

Pollutant	Emission Unit	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reduction?	Notes
PM_{10}	North and South Boilers	Multiclone Collectors	Yes	Yes	Yes	Multiclone collectors are currently installed and operating on the north and south boilers
		Electrostatic Precipitators (ESP)	Yes	Yes	Yes	Dry ESPs are already installed and operating on the north and south boilers.
		Fabric Filter	No	N/A	No	Fabric filters are not technically feasible due to fire safety concerns and ash produced during combustion.
		Wet Scrubber	N/A	N/A	N/A	Anticipated control efficiencies are less effective than existing controls.
	Storage Piles	Water Spray Suppression	Yes	Yes	Yes	Water spray is currently used for the storage piles at the Biomass One plant.
		Chemical Spray Suppression	No	N/A	No	Chemical suppressants are not feasible because they introduce pollutants to the fuel used in the boilers.

It is also worth noting that these boilers were each permitted under EPA's PSD program and were determined to meet BACT at the time those permits were issued, and the sources constructed.

This report outlines Biomass One's evaluation of possible options for reducing the emissions of NO_X, SO_2, and PM_{10} at its White City plant in White City, OR. There are currently no technically feasible and cost-effective reduction options available beyond current emission controls and best practices for the Biomass One facility. Therefore, the baseline emissions provided in this analysis are expected to be the same as those of the control scenario for the Biomass One White City plant.

2. INTRODUCTION AND BACKGROUND

2.1 Regional Haze Program Background

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, anthropogenic visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(*i*)):

> A. *consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*
>
> B. *Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*

With the second planning period under way for regional haze efforts, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature to compare manmade source contributions against.

2.2 Request for Biomass One Four-Factor Analysis

DEQ requested Biomass One's assistance in developing a four-factor analysis of potential emission reduction options for NO_X, SO_2, and PM_{10} at the plant. Biomass One understands that the information provided in a four-factor review of control options will be used by DEQ and the EPA in their evaluation of reasonable progress goals for Oregon. The purpose of this report is to provide information to DEQ regarding potential NO_X, SO_2, and PM_{10} emission reduction options for the Biomass One plant. Based on the Regional Haze Rule, associated EPA guidance, and DEQ's request, Biomass One understands that DEQ will only move forward with requiring emission reductions from the Biomass One plant if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional Haze

Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

2.3 Four-Factor Analysis Structure

The information presented in this report considers the following four factors for the emission reductions:

Factor 1. Costs of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of the units

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[1] for conducting a review of Best Available Retrofit Technology (BART) for a unit[2]. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for NO_X, SO_2, and PM_{10} can be found in Sections 5, 6, and 7 of this report, respectively. Section 4 of this report includes information on the Biomass One plant existing/baseline emissions.

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[1] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

[2]References to BART and BART requirements in this Analysis should not be construed as an indication that BART is applicable to the Biomass One plant.

3. SOURCE DESCRIPTION

The Biomass One White City plant is located in Jackson County, Oregon, approximately 9 miles north of Medford, OR. The nearest Class I area to the plant is the Mountain Lakes Wilderness Area, which is approximately 39 miles (63 kilometers) east of the Biomass One plant. An aerial image of the facility (with the facility boundary in red) is provided in Figure 3-1 below.

Figure 3-1. Biomass One White City Plant

The facility has two boilers, designated "North Boiler" and "South Boiler," as well as a small space heater, various storage piles, and additional insignificant sources. The two boilers are essentially identical in design and permitted throughput. The boilers fire wood products as fuel, with natural gas used for startup periods. Operating parameters for both boilers are provided in Table 3-1 below.

The storage piles at the facility are large – the four piles that comprise emission unit ID (EU ID) 049 have a combined potential footprint (permitted limit) of 60,394 square meters.

The boilers currently use multiclone collectors followed by dry electrostatic precipitators (ESPs) for control of PM_{10}, and the PM_{10} emissions from the storage piles are controlled using wet suppression. NO_x is controlled in both boilers using a combustion technique known as staged combustion. There are no current SO_2 controls on the north or south boilers.

Table 3-1. Boiler Operating Parameters

Operating Parameter [a]	North Boiler	South Boiler	Units
Heat Input Capacity	249	249	MMBtu/hr
Stack Temperature	303	312	°F
Stack Flow Rate	100,187	102,558	acfm
Moisture Content	17.6	20.5	%
2019 Annual Operating Hours	6,041	6,049	hr/year

a. Operating parameters for the boilers are obtained from the most recent stack test, conducted in August 2019. Heat input capacities are the nameplate heat capacities for each unit.

Biomass One was selected to complete a four-factor analysis based on the screening process employed by DEQ. For comparison to the appropriate Q/D threshold used by the DEQ as part of its selection process, the plant site emission limit (PSEL) emissions were used.[3] The PSELs for each emission unit are summarized in Table 3-1 below.

Table 3-2. PSEL Summary

Emission Unit	EU ID	Annual Emissions Limits (ton/yr)		
		NO_X	SO_2	PM_{10}
North Boiler	011	233.73	10.88	7.10
South Boiler	012	233.73	15.58	7.20
Space Heater	013	5.99E-03	2.13E-01	--
Storage Piles	049	--	--	14.50
Aggregate Insignificant/Additional [a]	--	--	--	2.20

a. The aggregated insignificant and additional sources include air knives, fuel handling and processing, vehicle traffic, and loaders.

Given the low rates of emissions from the space heater and aggregated insignificant or additional small sources, any emissions reductions would result in a minimal impact on visibility impairment in the region. Therefore, only the boilers and the storage piles will be evaluated further in this analysis. Further details of the fuel throughputs and emission rates are provided in Section 4.

[3] The Q/D metric refers to the ratio of a facilitiy's total emissions (Q) to the distance to the nearest class one area (D). All facilities were evaluated using the Q/D metric if they had a value of Q >25 tons per year of combined NO_X, SO_2, and PM_{10} emissions. While the Q/D metric was evaluated for both PSEL and actual emissions, a Q_{PSEL}-based Q/D threshold of 5 was used to determine which facilities were required to conduct a four-factor analysis, capturing 80% of total Q for Title V major sources.

4. EXISTING EMISSIONS

This section summarizes emission rates that are used as baseline rates in the four-factor analysis presented in Sections 5 through 7 of this report.

While the PSEL emissions are used for the screening process, they are not representative of actual emissions at a given facility, and thus are not an appropriate emissions baseline for use in determining the cost effectiveness and anticipated emissions reductions from a given emissions reduction method. The Western Regional Air Partnership (WRAP) modeling plan specifically describes the emissions used for modeling regional haze program benefits as those of "normal" current operations. The emissions used for the analysis should "best reflect current emissions profile for each source potentially impacting Class I area visibility [source(s) identified from Q/D analysis]." [4] Additionally, the EPA specifies in its "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" that the baseline emissions used for the analysis are used for "measuring the incremental effects of potential reasonable progress control measures on emissions, cost, visibility, and other factors." [5] The EPA recommends that states "express the cost of compliance in terms of a cost/ton of emissions reduction metric, and that the emission reduction used as the denominator for the cost/ton metric be the annual tons of reduction from implementation of the additional measure." [6] Therefore, for the purposes of this four-factor analysis, control technologies and their associated costs will be calculated using a basis of actual annual emissions, rather than permitted emission limits.

In the case of the boilers, actual SO_2 emissions are determined using the average pound per hour emission rates, as determined by CEMS data; and multiplying by the hours of operation in 2019. For PM_{10} and NO_X, stack test data are used to determine the boiler-specific pound per 1,000 pounds of steam (lb/Mlbs Steam) emission factor.[7] These emission factors are multiplied by the actual 2019 steam production to determine annual emissions. Storage pile emissions are consistent with the 2019 annual report submission and are based on recorded surface area and permitted emission factors, developed using AP-42 emission factors. Baseline annual emissions are summarized in Table 4-1 below.

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[4] Western Regional Modeling Plan – Spring 2019 Update. Western Regional Air Partnership, https://www.wrapair2.org/pdf/WesternModelingPlan%20update%20Spring_2019.pdf

[5] Tsirigotis, P. "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period." United States Enfironmental Protection Agency. 2019 August 20. Page 30. https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[6] Ibid, Page 31.

[7] The stack test data shows an emission factor for PM; this is converted to PM_{10} using the permitted factor of PM x 0.74 = PM_{10}.

Table 4-1. Baseline Emissions

Emission Unit	EU ID	Baseline Emission Rate (ton/yr)		
		NO_X [a]	SO_2 [a]	PM_{10} [b]
North Boiler	011	131.09	7.39	4.67
South Boiler	012	166.01	10.42	3.94
Storage Piles	049	--	--	1.39

a. NO_X emissions are calculated using the 2015 stack test results to determine the boiler-specific pound per 1,000 pounds of steam (lb/Mlbs Steam) emission factor and actual steam production from 2019. SO_2 emissions are calculated using CEMS data to determine the pound per hour (lb/hr) rate of emissions and the 2019 operating hours.

b. PM_{10} emission rates are calculated using the ODEQ Method 5 2019 PM stack test results to determine the boiler specific lb/Mlbs Steam emission factor and the actual steam production in 2019. 74% of PM emissions are PM_{10}, per permit. Storage pile baseline emissions are calculated using the permitted emission factors multiplied by the surface area of the piles, as recorded in 2019.

5. NO_X FOUR-FACTOR EVALUATION

The baseline NO_X emission rates that are used in the NO_X four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. Of the units considered in this four-factor analysis, only the north and south boilers (EU ID 011 and 012) emit NO_X. Search results from the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database are provided as a reference in Appendix A of this report, and detailed cost calculations for NO_X emission controls are provided in Appendix B.

5.1 Step 1: Identification of Available Retrofit NO_X Control Technologies

Nitrogen oxides, NO_X, are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is admitted to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel. Technical literature suggests that NO_X formation from wood combustion is primarily fuel NO_X.[8]

"Fuel NO_X" forms when the fuel bound nitrogen compounds are converted into nitrogen oxides. The amount of fuel bound nitrogen converted to fuel NO_X depends largely upon the fuel type, nitrogen content of the fuel, air supply, and boiler design (including combustion temperature). The reaction between elemental nitrogen and oxygen to form nitrogen oxides happens very rapidly. Therefore, the primary mechanisms for reducing fuel NO_X involve creating a minimum amount of excess oxygen available to react with the fuel bound nitrogen throughout the combustion process.[9]

NO_X formed in the high-temperature, post-flame region of the combustion equipment is "thermal NO_X." Temperature is the most important factor in determining the quantity of thermal NO_X formed, and at flame temperatures above 2,200°F, thermal NO_X formation increases exponentially.[10]

Nitrogen oxide (NO) formation is inherent in all high temperature combustion processes. Nitrogen dioxide (NO_2) can then be formed in a reaction between the NO and oxygen in the combustion gases. In stationary source combustion, little of the NO is converted to NO_2 before being emitted. However, the NO continues to oxidize in the atmosphere. For this reason, all NO_X emissions from boilers are usually reported as NO_2, as is the case in this report.

Step 1 of the top-down control review is to identify available retrofit control options for NO_X. The available NO_X retrofit control technologies for the Biomass One boilers are summarized in Table 5-1. Control technologies were identified based on entries for similar units in the RBLC database, EPA Air Pollution Technology documents, and experience with similar units in the industry.

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[8] Webster, T.S. and S. Drennan. *Low NO_X Combustion of Biomass Fuels.* Coen Company, Inc. http://www.coen.com/i_html/white_lownoxbiom.html.

[9] Kraft, D.L. *Bubbling Fluid Bed Boiler Emissions Firing Bark & Sludge.* Barberton, OH: Babcock & Wilcox. September 1998. http://www.babcock.com/library/pdf/BR-1661.pdf.

[10] Kraft, D.L. *Bubbling Fluid Bed Boiler Emissions Firing Bark & Sludge.* Barberton, OH: Babcock & Wilcox. September 1998. http://www.babcock.com/library/pdf/BR-1661.pdf.

Table 5-1. Available NO_X Control Technologies for Biomass One Boilers

NO_x Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Fuel Staging Low NO_x Burners (LNB) Low Excess Air Staged Combustion
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 5-1, can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the boilers, which minimizes NO_X formation. Post-combustion controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

5.1.1 Combustion Controls

5.1.1.1 Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) involves recycling a portion of the flue gas back into the combustion zone where inert combustion products in the recycled gas stream adsorb some of the heat generated by the combustion process, thus lowering peak flame temperature. The reduction of the peak flame temperature reduces the formation of thermal NO_X (reaction of N_2 and excess oxygen in the combustion air to form NO_X due to high temperatures of combustion).

5.1.1.2 Fuel Staging

Also known as "reburning" or "off-stoichiometric combustion," fuel staging is a technique where 10 to 20 percent of the total fuel input is diverted to a second combustion zone downstream of the primary zone. The fuel in the secondary zone serves as a reducing agent, and NO formed in the primary combustion zone is reduced to N_2. This technique usually employs natural gas or distillate oil as the fuel in the secondary combustion zone.

5.1.1.3 Low NO_X Burners

Traditional burner design introduces both the fuel and air into one combustion zone. To obtain optimal flames, large amounts of excess air must be combined with the fuel. This relatively "uncontrolled" combustion creates high flame temperatures and therefore higher NO_X emissions.

To control the generation of thermal NO_X, LNB technology stages combustion in the high temperature zone of the flame. The first stage is a fuel-rich, oxygen-lean atmosphere where little oxygen is available for NO_X formation, which reduces peak flame temperatures by delaying the completion of the combustion process. Combustion takes place downstream in the second stage where excess air is available, but temperatures are lower than the hottest portion of the primary flame core. LNB technology is most suitable for oil and gas combustion.

5.1.1.4 Low Excess Air (LEA)

LEA involves reducing the amount of excess combustion air to near-stoichiometric levels and reducing flame temperature, therefore decreasing thermal NO_X formation.

5.1.1.5 Staged Combustion

Staged combustion technologies such as Overfire Air (OFA) reduce NO_X emissions by creating a “fuel-rich” zone via air staging. Air staging involves diverting a portion of the air required through separate ports so that partial combustion is carried out in the first stage with a lower air to fuel ratio than that of normal combustion, while secondary air is supplied to complete the combustion reaction in a subsequent combustion stage. Fuel-rich conditions in the first stage reduce fuel NO_X formation, specifically, by limiting the amount of oxygen available to react with the fuel-bound nitrogen. Conditions in the secondary combustion zone result in lower peak temperatures and thus, lower NO_X emissions.

5.1.2 Post Combustion Controls

5.1.2.1 Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 480˚F to 800˚F, the reaction can result in removal efficiencies between 70 and 90 percent.[11] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700˚F and 750˚F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease. Search results from the RBLC database indicate that SCRs have not been installed on wood-fired boilers of this size for programs like PSD BACT.[12]

5.1.2.2 Selective Non-Catalytic Reduction

SNCR is an exhaust gas treatment process in which urea or ammonia is injected into the exhaust gas. High temperatures, normally between 1,600 and 2,100°F, promote the reaction between urea or ammonia and NO_X to form N_2 and water without the use of a catalyst.[13] The effectiveness of SNCR systems depends on the inlet NO_X concentration, temperature, mixing, residence time, reagent-to-NO_X ratio, and fuel sulfur content. The temperature of the system must fall within the appropriate range to avoid excess ammonia slip or the oxidation of NH_3 to NO_X. Proper mixing of the reagent and the flue gas is necessary to ensure reduction of NO_X. The residence time must be of an appropriate duration to allow completion of the reaction. If the reagent-to-NO_X ratio is too high, excess NH_3 will become present in the exhaust.

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[11] EPA Air Pollution Control Cost Manual, Section 4, Chapter 2, “Selective Catalytic Reduction.” Pages 2-9 and 2-10. June 2019. https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

[12] RBLC search results are provided in Appendix A of this report.

[13] EPA, Air Pollution Control Technology Fact Sheet, EPA-452/F-03-031, Selective Non-Catalytic Reduction (SNCR), dated July 15, 2003.

Outside of the design temperature window, the emissions are adversely affected. If the temperatures are too high, then the reagent may be oxidized, causing additional NO_X emissions. If the temperatures are too low, then the reaction between the reagent and NO_X is slowed, and emissions of the reagent will be present.

5.2 Step 2: Eliminate Technically Infeasible NO_X Control Technologies

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

5.2.1 Combustion Controls

Given the high moisture content inherent in the wood products (in part due to watering of piles control) used as fuel for the boilers and the temperature ranges reached in the boilers, thermal NO_X formation is relatively low. High moisture content in the fuel and combustion air results in latent heat absorption that results in lower temperatures in the combustion zone. Therefore, combustion controls focused primarily on thermal NO_X reduction are not considered further in this analysis (FGR, LEA).

Combustion modification technologies used with traditional gas and oil burners, such as LNB and fuel staging, are not available for wood-fired boilers.[14]

5.2.1.1 Staged Combustion

The Biomass One boilers already employ staged combustion air in primary, secondary, and tertiary zones, reducing fuel NO_X formation. The benefits of staged combustion are therefore already represented in the baseline emission calculations. All additional controls evaluations will assume that staged combustion is used.

5.2.2 Post Combustion Controls

5.2.2.1 Selective Catalytic Reduction

Implementing SCR on industrial hog fuel boilers poses several technical challenges. First, size constraints often make retrofitting an SCR system near the boiler impossible. Second, most hog fuel boilers' temperature profiles are not appropriate for SCR, and the SCR system pressure drop requirements create sizing concerns related to existing boiler fans. Third, the high PM concentrations upstream of the PM control equipment (Hot-side/High-dust) would impede catalyst effectiveness and could result in deactivation or poisoning of the catalyst, which requires downtime to clean and/or replace the catalyst. The installation of SCR downstream of the PM control equipment (Cold-side/Tail-end SCR) would render the gas stream too cold for an effective reaction with the catalyst to reduce NO_X.[15] In biomass boilers, plugging and fouling of the catalyst can occur due to large amounts of fly ash generated by the biomass.

[14] LNB described in the RBLC is for heating the exhaust stream where post combustion controls are applied. The LNB is not directly used in wood fired boilers.

[15] EPA Air Pollution Control Cost Manual, Section 4, Chapter 2, "Selective Catalytic Reduction." June 2019. https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

The desired minimum temperature for SCR application to achieve 70% control is 575°F.[16] In order to achieve 95% control, 700°F is required.[17] The maximum exhaust temperatures (after the PM control devices) of the north and south boilers are 320°F and 324°F, respectively. Higher temperatures would be needed for optimum control efficiency for tail-end SCR application.

As noted above, locating the SCR in a higher temperature region (Hot-side/High-Dust SCR) to avoid the issue with use of auxiliary fuel would result in exposure to high particulate emissions from hog fuel combustion that could significantly damage the catalyst.

The technical difficulties described above apply generally to biomass boilers, and recent applications indicate that advanced technologies and auxiliary heating of the tail-end flue gas may overcome these difficulties. However, RBLC search results indicate that SCR has not been successfully employed on wood-fired boilers of this size.[18]

Regional Haze guidelines state that technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; thus, technologies that have not been successfully implemented on a comparable emission unit, such as SCR on wood fired boiler of this size, are considered to be technically infeasible. Nevertheless, an economic analysis has been conducted on the boilers to further demonstrate the infeasibility of the tail-end SCR application on the boilers. The demonstration of the economic infeasibility of the SCR technology is included under Step 3.

5.2.2.2 Selective Non-Catalytic Reduction

While there have been recent advancements in SNCR technology, such as setting up multiple injection grids and the addition of sophisticated Continuous Emissions Monitoring Systems (CEMS)-based feedback loops, implementing SNCR on industrial hog fuel boilers continues to pose several technical challenges.

The primary concern for smaller boilers and or package units is adequate wall space within the boiler for installation of injectors. Additionally, adequate space adjacent to the boiler is required for the distribution system equipment and for performing maintenance. Given the anticipated amount of space required for the injectors and distribution system equipment, Biomass One does not anticipate that the injectors would have the physical space to be installed prior to the existing PM control equipment (multiclones and dry ESPs). Furthermore, challenges related to footprint are expected should a unit like this be installed after the PM control equipment.

In a SNCR system, the injection of the reagent must be applied in a narrow temperature window in order for the reduction reaction to successfully complete. As mentioned in Section 5.1.2.2, high temperatures, normally between 1,600 and 2,100°F, promote the reaction between urea or ammonia and NO_X to form N_2 and water. The Biomass One boilers have thermocouples that allow for operators to monitor temperature in the boilers, allowing for more precise control of various pollutants. Temperature readings in the combustion chamber indicate peak temperatures in both boilers are typically between 1,450 and 1,550°F. Installation of SNCR prior to the multiclones and ESPs would potentially allow for a more reasonable temperature difference to the point where reheating the exhaust stream to the appropriate temperature would be reasonable. However, given the limited footprint surrounding the units, installation of injection nozzles and

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[16] EPA Cost Manual Section 4.2 Figure 2.2 shows that the optimum temperature for operation of SCR with 70% removal efficiency is approximately 575°F.

[17] Ibid.

[18] A single RBLC entry explicitly lists SCR as a control, but has a heat input capacity of over 1,300 MMBtu/hr.

an associated injection system would require renovating an entire section of the boiler itself. Therefore, Biomass One would be required to heat the exhaust stream from approximately 320°F to, minimally, 1600°F.

SNCR has higher effectiveness with higher uncontrolled NO_X levels. Typical SNCR units are best suited for 200-400 parts per million (ppm) concentrations. Based on Biomass One historical stack testing, concentrations of NO_X ranges from 120-150 ppm. Stack testing is completed during high production periods, indicating that these concentrations are generally on the high end of concentrations produced by the boilers. This low concentration exhaust will result in a lower control efficiency.

Another consideration for this type of control technology is the use of ammonia or urea. Ammonia is also a visibility-impacting pollutant. and emissions of unreacted ammonia would therefore be counter to the goals of the regional haze program. If there is incomplete reaction of the NO_X and the ammonia, unreacted ammonia is emitted. This is often referred to as ammonia slip. Ammonia slip is generally seen at higher levels for lower NO_X concentration exhaust streams. If the SNCR uses urea as the reagent, a by-product of this reaction is nitrous oxide (N_2O), a greenhouse gas pollutant. This report is not specifically concerned with greenhouse gas pollutants, but this may be a consideration for overall environmental impact.

With exhaust stack temperatures over 1,200°F below the necessary range for successful SNCR implementation, the large physical footprint of the SNCR, and low concentration of pollutant; this technology is considered technically infeasible for these boilers.

5.3 Step 3: Rank of Technically Feasible NO_X Control Options by Effectiveness

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 5-2 presents potential NO_X control technologies for the boilers and their associated control efficiencies.

Table 5-2. Ranking of NO_X Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
NO_X	SCR Staged Combustion	90 * Base case

* A 90% control efficiency is conservatively assumed based on the EPA Air Pollution Control Technology Fact Sheet for SCR. https://www3.epa.gov/ttncatc1/cica/files/fscr.pdf Additional unit-specific evaluations and engineering design are necessary to determine the actual achievable control efficiency for these boilers.

5.4 Step 4: Evaluation of Impacts for Feasible NO_X Controls

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1 Cost of Compliance

In order to assess the cost of compliance for the installation of SCR, the EPA Control Cost Manual is used. Capital costs for the installation of the SCR assumed a 20-year life span for depreciation, as well as the bank prime rate of 4.75% for interest calculations.[19] The total capital investment includes the capital cost for the SCR itself and the balance of the plant. Annual costs include both direct costs such as maintenance, reagent, electricity, and catalyst replacement and indirect costs for administrative charges and the amortized capital costs as a capital recovery value. An additional direct cost included in these calculations is the cost for reheating the flue gas stream using natural gas following the particulate control device. This estimate conservatively omits the capital cost of installing any heat exchangers and fuel storage/transport associated with the reheating of the gas stream. The total costs and cost effectiveness of SCR are summarized in Table 5-3, below. Full details of the cost calculation may be found in Appendix B.

Table 5-3. SCR Cost Calculation Summary

Emission Unit	Total Capital Investment	Total Annual Cost	NOx Emissions Removed [a] (tpy)	NOx Emissions Added [b] (tpy)	Cost Effectiveness [c] ($/ton removed)
North Boiler	$5,316,814	$1,606,673	118	4	$14,131
South Boiler	$5,316,814	$ 1,611,505	149	4	$11,100
Total Project	$10,633,627	$3,218,178	259	8	$12,431

a. Baseline NO_X emissions are based on boiler-specific stack test data and 2019 steam production from each boiler. Total removed NO_X emissions are calculated using the 90% control efficiency, minus the NO_X emissions that would be generated during the combustion of natural gas for heating the exhaust stream.
b. NOx Emissions are added due to natural gas combustion associated heating the exhaust to appropriate control temperatures.
c. Cost Effectiveness = Total Annual Cost / (NOx Emissions Removed – NOx Emissions Added)

5.4.2 Timing for Compliance

Biomass One believes that reasonable progress compliant controls are already in place. However, if DEQ determines SCR is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the next annual non-generation period, within 2 years of notice of a required installation.

5.4.3 Energy Impacts and Non-Air Quality Impacts

As previously stated, the cost of energy required for successful operation of the SCR are included in the calculations, which can be found in detail in Appendix B. An SCR installation is expected to decrease the

[19] These values are consistent with those recommended by DEQ in their "Regional Haze: Four Factor Analysis" Fact Sheet. The bank prime rate at the date of the DEQ's letter is used in this cost analysis, rather than today's bank prime rate, due to substantial fluctuations resulting from the COVID-19 pandemic. Those immediate fluctuations from COVID-19 are not expected to be representative of long term borrowing rates over the length of the amortization period. https://www.oregon.gov/deq/aq/Documents/Haze-FourFactorAnlaysis.pdf

efficiency of the overall facility, particularly as significant energy use is needed beyond current plant operation requirements and additional fuel firing is required to compensate for the efficiency loss.

5.4.4 Remaining Useful Life

Biomass One has assumed this control equipment will last for the entirety of the 20-year amortization period, which is reflected in the cost calculations.

5.5 NO_X Conclusion

The facility currently uses staged combustion in its boilers to minimize NO_X emissions. SNCR is not technically feasible for these boilers given stack temperatures over 1,200°F below the necessary range for successful SNCR implementation, the large physical footprint of the SNCR, and low concentration of pollutant range. SCR application with wood-fired boilers is limited, and there are significant technical concerns associated with the high dust loading in the flue gas and temperatures below the necessary range for effective SCR implementation. Calculations indicate the control does not represent a cost-effective control technology given the limited expected improvements to NO_X emission rates, high uncertainty of successful implementation, high capital investment, and resulting high cost per ton NO_X removed.

6. SO_2 FOUR-FACTOR EVALUATION

The baseline SO_2 emission rates that are used in the SO_2 four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. Of the units considered in this four-factor analysis, only the north and south boilers (EU ID 011 and 012) emit SO_2.

SO_2 emissions in boilers occur as a result of the combustion of sulfur contained in the fuel. Fuel sulfur contents for wood products used as fuels are relatively low when compared to fuels like coal, and thus the control technology applications, particularly for smaller wood-fired units, are fairly limited. A study in the Journal of the Air Pollution Control Association indicates that less than 10% of sulfur contained in bark combusted as fuel is released as SO_2 via stack gas.[20] The majority of the sulfur content is combined with the ash products of combustion. An examination of RBLC search results for SO_2 control on biomass fired boilers yields fairly limited results:

- Three units, substantially larger in size (458.5, 536, and 1,358 MMBtu/hr), employ SO_2 controls.
  - One unit uses a wet scrubber for biogas that is used as fuel and thus is not applicable for these boilers.
  - All three use a dry sorbent injection system.
- The only unit of comparable size to the boilers at the Biomass One facility does not use any controls for SO_2 emissions.

Additionally, SO_2 emissions from both the north and south boilers are already at or below the most stringent levels represented in the RBLC search results. The most stringent SO_2 emission limits, on a pounds SO_2 per million Btu heat input rate (lb/MMBtu) basis, are 0.06 lb/MMBtu. Emissions from the north and south boilers are 0.03 and 0.04 lb/MMBtu, respectively.[21]

Biomass One concludes that no additional emissions controls are necessary for the north and south boilers, as current operations result in SO_2 emission rates that are lower than those required by the Prevention of Significant Deterioration Best Available Control Technology (PSD BACT) program.

[20] Oglesby, H.S. and Blosser, R.O. (1980). "Information on the Sulfur Content fo Bark and its Contribution to SO_2 Emissions when Burned as a Fuel," Journal of the Air Pollution Control Association, DOI: 10.1080/00022470.1980.10465107 https://www.tandfonline.com/doi/pdf/10.1080/00022470.1980.10465107

[21] Emissions are calculated on a lb/MMBtu basis using the baseline emissions and rated heat input capacity provided in Sections 3 and 4, above.

7. PM_{10} FOUR-FACTOR EVALUATION

The baseline PM_{10} emission rates that are used in the PM_{10} four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report.

7.1 PM_{10} Control Evaluation for Storage Piles

The Biomass One plant already employs water sprays for wet dust suppression at the plant. Use of chemical suppressants is not feasible for the wood piles, as the introduction of chemicals to the wood will result in unwanted pollutants being introduced to the combustion taking place in the boilers. The plant also maintains a fugitive dust control plan to ensure PM_{10} emissions from the storage piles are minimized. PM_{10} emissions from the storage piles are minimal (representing less than one third of total particulate emissions from the storage piles), and thus will not be evaluated further for emission reductions in this analysis. The following sections document the four-factor analysis for PM_{10} emissions from the north and south boilers.

7.2 Step 1: Identification of Available Retrofit PM_{10} Control Technologies

PM_{10} emissions from the boilers are generated from combustion of wood fuel. There are four main types of PM_{10} control techniques: cyclone collectors, fabric filters or baghouse, venturi wet scrubbers, and dry and wet ESPs. The potentially applicable PM_{10} control technologies are identified based on experience with similar boilers and review of the RBLC database. The plant currently uses multiclone collectors followed by dry ESPs for PM_{10} control on the boilers; therefore, only fabric filters and wet venturi scrubbers will be evaluated further in this analysis.

7.2.1 Fabric Filters

Fabric filters, sometimes are referred to as baghouses or dust collectors, collect the particulates on the surface of the filter bags. The control efficiency varies depending on the fabric material as well as the particle size. Most of the fabric filters can remove in excess of 99 or 99.9 percent of the particulates in the gas stream, and the layer of dust collected on the fabric usually serves for such high efficiency. Application of fabric filters is typically limited by the exhaust gas characteristics: for example, sticky particles or corrosive gas streams will plug the filters or result in corrosion to the fabric thus shortening the life of the fabric filters significantly. High carbon content in wood ash generated during combustion and collected by these potential filters is likely to lead to a substantial fire hazard.

7.2.2 Wet Venturi Scrubber

Wet scrubbers use a scrubbing liquid to capture pollutants in a gas exhaust stream. In a venturi scrubber, "a 'throat' section is built into the duct that forces the gas stream to accelerate as the duct narrows and then expands."[22] Venturi scrubber control efficiencies range from 70 to greater than 99 percent depending on the application.

7.3 Step 2: Eliminate Technically Infeasible PM_{10} Control Technologies

Step 2 of the top-down control review is to eliminate technically infeasible PM_{10} control technologies that were identified in Step 1.

[22] EPA Air Pollution Control Technology Fact Sheet, Venturi Scrubber. https://www3.epa.gov/ttncatc1/cica/files/fventuri.pdf

7.3.1 Fabric Filters

Despite the high removal efficiency of fabric filters, collected dust must be removed and disposed of properly to ensure the continuous operation of the fabric filters. For wood-fired boilers, the ash typically contains high amount of carbon that would create a substantial fire hazard. Therefore, fabric filters are rarely applied to wood-fired boilers and thus considered technically infeasible in this case.

7.3.2 Wet Venturi Scrubber

Though wet scrubbers are found in industries like pulp and paper, the use of multiclone collectors and ESPs is consistent with BACT determinations for wood-fired boilers in the RBLC database, and wet scrubbers are not listed for boilers. Additionally, the current PM_{10} controls were determined to achieve the Lowest Achievable Emission Rate (LAER) when the permits were evaluated in 1984 and were determined to be consistent with BACT when the particulate controls were replaced in 1989.

Given the consistency with BACT determinations around the country, a program more stringent than the regional haze program, and the higher anticipated levels of emissions control compared to the currently installed PM_{10} control devices,[23] a wet scrubber is not considered technically feasible for PM_{10} emissions reductions for the boilers.

7.4 PM_{10} Conclusion

Biomass One concludes that no additional emissions controls are necessary for the north and south boilers, as the current use of in-series multiclone collectors and dry ESPs as emissions controls for PM_{10} are consistent with those required for the PSD BACT program, and any additional controls would result in minimal improvement, particularly in the scope of the regional haze program and the ensuing effect on visibility impairment in the region.

[23] EPA Control technology fact sheets indicate dry ESPs have an estimated control efficiency of between 99 and 99.9% for new installations, compared to control efficiencies from 70 to 99% for wet scrubbers. While similar efficiencies can generally be achieved, dry ESPs represent at worst a comparable level of emissions control. https://www3.epa.gov/ttncatc1/cica/atech_e.html

APPENDIX A. RBLC SEARCH RESULTS

Table A-1. RBLC Database Search Results - Process Type 12.120 - Biomass Industrial-Size Boilers/Furnaces (>100 MMBtu/hr to <= 250 MMBtu/hr)

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	AGENCY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	SOUTHEAST RENEWABLE FUELS (SRF), LLC	FL	FLORIDA DEPT. OF ENVIRONMENTAL PROTECTION	PSD-FL-412 (0510032-001-AC)	12/23/2010	Cogeneration Biomass Boiler	biomass	536	MMBTU/H	Nitrogen Oxides (NOx)	Controls: Good combustion practices (GCP) leading to the efficient combustion of biomass in the boiler, including an over-fired air (OFA) system, to minimize formation of PM, nitrogen oxides (NOX), Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR) or a combination of the two with urea or anhydrous ammonia (NH3)	0.1	LB/MMBTU
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	GAINESVILLE REGIONAL UTILITY (GRU) DEERHAVEN	FL	FLORIDA DEPT. OF ENVIRONMENTAL	PSD-FL-411 (0010131-001-AC)	12/28/2010	Biomass bubbling fludized bed (BFB) boiler	biomass	1358	MMBTU/H	Nitrogen Oxides (NOx)	Efficient Combustion. SCR system	1	LB/MW-H
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	FLORIDA DEPT. OF ENVIRONMENTAL	PSD-FL-416, 0550063-001-AC	9/23/2011	Biomass Boiler, Emission Unit 002	biomass	458.5	MMBTU/H	Nitrogen Oxides (NOx)	Selective Non-Catalytic Reduction (SNCR) with urea or anhydrous ammonia (NH3) injection to destroy NOX;; use of natural gas fired in low-NOX burners (LNB)	0.1	LB/MMBTU
ME-0040	ROBBINS LUMBER, INC.	ROBBINS LUMBER, INC.	ME	MAINE DEPARTMENT OF ENV PROTECTION	A-156-77-3-A	6/30/2017	Biomass Boiler #3	Biomass	167.3	MMBTU/H	Nitrogen Oxides (NOx)	Flue Gas Recirculation (FGR) and Selective Non-Catalytic Reduction (SNCR) SNCR only required if facility cannot meet 0.15 lb/MMBtu emission limit within 365 days	25.1	LB/H
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	59-16	8/26/2016	Thermal Energy Plant (EUENERGY in FGDRYERRTO)	Wood-derived fuel & biomass	110	MMBTU/H	Nitrogen Oxides (NOx)	Good combustion practices and low NOx burners.	95	LB/H
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	59-16A	5/9/2017	EUENERGY in FGDRYERRTO (Thermal Energy Plant)	Wood derived fuel and biomass	110	MMBTU/H	Nitrogen Oxides (NOx)	Good combustion practices and low NOx burners	95	LB/H
OH-0343	SMART PAPERS-HAMILTON MILL	SMART PAPERS	OH	OHIO ENVIRONMENTAL PROTECTION	P0106289	11/1/2010	Spreader Stoker Boiler	Biomass	249	MMBtu/H	Nitrogen Oxides (NOx)		163.5	LB/H
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU001	WET BARK, WOOD	120	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.14	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU002	WET BARK, WOOD	120	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.14	LB/MMBTU
SC-0117	SPRINGS GLOBAL US, INC. - GRACE COMPLEX	SPRINGS GLOBAL US, INC.	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1460-0003-DG	11/6/2010	INDUSTRIAL-SIZE BOILERS/FURNACES	WOOD BIOMASS	195	MMBTU/H	Particulate Matter (PM)	MULTICLONE (80%); ESP (92%) - EACH	0.059	LB/MMBTU - EACH
SC-0117	SPRINGS GLOBAL US, INC. - GRACE COMPLEX	SPRINGS GLOBAL US, INC.	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1460-0003-DG	11/6/2010	UTILITY- AND LARGE INDUSTRIAL-SIZE BOILERS/FURNACES	WOOD BIOMASS	260	MMBTU/H	Particulate Matter (PM)	MULTICLONE (80%); ESP (92%)	0.059	LB/MMBTU

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	AGENCY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	SOUTHEAST RENEWABLE FUELS (SRF), LLC	FL	FLORIDA DEPT. OF ENVIRONMENTAL	PSD-FL-412 (0510032-001-AC)	12/23/2010	Cogeneration Biomass Boiler	biomass	536	MMBTU/H	Particulate matter, filterable < 10 Âµ (FPM10)	A wet sand separator (cyclone) and a electrostatic precipitator (ESP) or fabric filter baghouse to further control PM and VE.	0.015	LB/MMBTU
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	GAINESVILLE REGIONAL UTILITY (GRU) DEERHAVEN	FL	FLORIDA DEPT. OF ENVIRONMENTAL	PSD-FL-411 (0010131-001-AC)	12/28/2010	Biomass bubbling fludized bed (BFB) boiler	biomass	1358	MMBTU/H	Particulate matter, filterable < 10 Âµ (FPM10)	Fabric Filter and Efficient combustion	0.015	LB/MMBTU
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	FLORIDA DEPT. OF ENVIRONMENTAL	PSD-FL-416, 0550063-001-AC	9/23/2011	Biomass Boiler, Emission Unit 002	biomass	458.5	MMBTU/H	Particulate matter, filterable < 10 Âµ (FPM10)	Electrostatic Precipitator	0.015	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU001	WET BARK, WOOD	120	MMBTU/H	Particulate matter, filterable < 10 Âµ (FPM10)	ESP	0.032	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU002	WET BARK, WOOD	120	MMBTU/H	Particulate matter, filterable < 10 Âµ (FPM10)	ESP	0.032	LB/MMBTU
SC-0117	SPRINGS GLOBAL US, INC. - GRACE COMPLEX	SPRINGS GLOBAL US, INC.	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1460-0003-DG	11/6/2010	INDUSTRIAL-SIZE BOILERS/FURNACES	WOOD BIOMASS	195	MMBTU/H	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	MULTICLONE (80%); ESP (92%) - EACH	0.043	LB/MMBTU - EACH
SC-0117	SPRINGS GLOBAL US, INC. - GRACE COMPLEX	SPRINGS GLOBAL US, INC.	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1460-0003-DG	11/6/2010	UTILITY- AND LARGE INDUSTRIAL-SIZE BOILERS/FURNACES	WOOD BIOMASS	260	MMBTU/H	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	MULTICLONE (80%); ESP (92%)	0.043	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU001	WET BARK, WOOD	120	MMBTU/H	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	ESP	0.032	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU002	WET BARK, WOOD	120	MMBTU/H	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	ESP	0.032	LB/MMBTU
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	59-16	8/26/2016	Thermal Energy Plant (EUENERGY in FGDRYERRTO)	Wood-derived fuel & biomass	110	MMBTU/H	Particulate matter, filterable (FPM)	Good combustion practices, dry ESP and RTO.	29.1	LB/H
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	59-16A	5/9/2017	EUENERGY in FGDRYERRTO (Thermal Energy Plant)	Wood derived fuel and biomass	110	MMBTU/H	Particulate matter, filterable (FPM)	Good combustion practices, dry ESP, RTO.	29.1	LB/H

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	AGENCY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU001	WET BARK, WOOD	120	MMBTU/H	Particulate matter, filterable (FPM)	ESP	0.0032	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU002	WET BARK, WOOD	120	MMBTU/H	Particulate matter, filterable (FPM)	ESP	0.0032	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU001	WET BARK, WOOD	120	MMBTU/H	Particulate matter, fugitive	ESP	0.032	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	SOUTH CAROLINA DEPT OF HEALTH & ENV CTRL, BUREAU OF AIR	1860-0128-CA	1/3/2013	BIOMASS BOILER EU002	WET BARK, WOOD	120	MMBTU/H	Particulate matter, fugitive	ESP	0.032	LB/MMBTU
ME-0040	ROBBINS LUMBER, INC.	ROBBINS LUMBER, INC.	ME	MAINE DEPARTMENT OF ENV PROTECTION	A-156-77-3-A	6/30/2017	Biomass Boiler #3	Biomass	167.3	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Dry Electrostatic Precipitator	7.9	LB/H
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	59-16	8/26/2016	Thermal Energy Plant (EUENERGY in FGDRYERRTO)	Wood-derived fuel & biomass	110	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices, dry ESP, RTO.	28.4	LB/H
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	59-16A	5/9/2017	EUENERGY in FGDRYERRTO (Thermal Energy Plant)	Wood derived fuel and biomass	110	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices, dry ESP, RTO.	28.4	LB/H
OH-0343	SMART PAPERS-HAMILTON MILL	SMART PAPERS	OH	OHIO ENVIRONMENTAL PROTECTION	P0106289	11/1/2010	Spreader Stoker Boiler	Biomass	249	MMBtu/H	Particulate matter, total < 10 Âµ (TPM10)	Baghouse	0.104	LB/MMBTU
ME-0040	ROBBINS LUMBER, INC.	ROBBINS LUMBER, INC.	ME	MAINE DEPARTMENT OF ENV PROTECTION	A-156-77-3-A	6/30/2017	Biomass Boiler #3	Biomass	167.3	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Dry Electrostatic Precipitator	7.9	LB/H
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	59-16	8/26/2016	Thermal Energy Plant (EUENERGY in FGDRYERRTO)	Wood-derived fuel & biomass	110	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices, dry ESP, RTO.	16.55	LB/H
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	59-16A	5/9/2017	EUENERGY in FGDRYERRTO (Thermal Energy Plant)	Wood derived fuel and biomass	110	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices, dry ESP and RTO.	16.55	LB/H
OH-0343	SMART PAPERS-HAMILTON MILL	SMART PAPERS	OH	OHIO ENVIRONMENTAL PROTECTION	P0106289	11/1/2010	Spreader Stoker Boiler	Biomass	249	MMBtu/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Baghouse	0.03	GR/DSCF

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	AGENCY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
OH-0343	SMART PAPERS-HAMILTON MILL	SMART PAPERS	OH	OHIO ENVIRONMENTAL PROTECTION	P0106289	11/1/2010	Spreader Stoker Boiler	Biomass	249	MMBtu/H	Particulate matter, total (TPM)	Baghouse	0.116	LB/MMBTU
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	SOUTHEAST RENEWABLE FUELS (SRF), LLC	FL	FLORIDA DEPT. OF ENVIRONMENTAL	PSD-FL-412 (0510032-001-AC)	12/23/2010	Cogeneration Biomass Boiler	biomass	536	MMBTU/H	Sulfur Dioxide (SO2)	Dry sorbent injection system. A wet scrubber to remove hydrogen sulfide from the biogas prior to combustion in the boiler to minimize SO2 emissions.	0.06	LB/MMBTU
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	GAINESVILLE REGIONAL UTILITY (GRU) DEERHAVEN	FL	FLORIDA DEPT. OF ENVIRONMENTAL	PSD-FL-411 (0010131-001-AC)	12/28/2010	Biomass bubbling fludized bed (BFB) boiler	biomass	1358	MMBTU/H	Sulfur Dioxide (SO2)	IDSIS to further control of SO2 and acid gas HAP	1.4	LB/MWH
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	FLORIDA DEPT. OF ENVIRONMENTAL	PSD-FL-416, 0550063-001-AC	9/23/2011	Biomass Boiler, Emission Unit 002	biomass	458.5	MMBTU/H	Sulfur Dioxide (SO2)	In-duct Sorbent Injection System	0.06	LB/MMBTU
OH-0343	SMART PAPERS-HAMILTON MILL	SMART PAPERS	OH	OHIO ENVIRONMENTAL PROTECTION	P0106289	11/1/2010	Spreader Stoker Boiler	Biomass	249	MMBtu/H	Sulfur Dioxide (SO2)		1.7	LB/MMBTU

Table A-2. RBLC Database Search Results - Storage Piles

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	AGENCY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
AR-0124	EL DORADO SAWMILL	UNION COUNTY LUMBER COMPANY	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	2348-AOP-R0	8/3/2015	MATERIAL PROCESSING SN-11		0		Particulate matter, total (TPM)	PROPER MAINTENANCE AND OPERATION	0.02	LB/T
AR-0124	EL DORADO SAWMILL	UNION COUNTY LUMBER COMPANY	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	2348-AOP-R0	8/3/2015	STORAGE PILES FOR BARK, SAWDUST, WOOD CHIPS SN-12		0		Particulate matter, total (TPM)	WATERING PILES	0.02	LB/T
CO-0074	RIO GRANDE CEMENT PLANT	GCC RIO GRANDE, INC.	CO	COLORADO DEPT OF HEALTH - AIR POLL CTRL	98PB0893	7/9/2012	Storage Piles		0		Particulate matter, filterable< 10 Âµ (FPM10)	Plant storage â€“ BACT is determined to be use of enclosure (covering the storage pile with tarps) Quarry storage â€“ BACT is determined to be use of the inherent moisture content	0	
CO-0074	RIO GRANDE CEMENT PLANT	GCC RIO GRANDE, INC.	CO	COLORADO DEPT OF HEALTH - AIR POLL CTRL	98PB0893	7/9/2012	Material processing& transfer		0		Particulate matter, filterable< 10 Âµ (FPM10)	Plant Fabric filters combined with enclosed transfer points was selected as BACT. Quarry The combination of high material moisture content and partial enclosure was selected as BACT.	0.005	GR/DSCF
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	T147-30464-00060	6/27/2012	TWO (2) STORAGE PILES		300000	TONS EACH	Particulate matter, total< 10 Âµ (TPM10)	WET SUPPRESSION WITH PILE COMPACTION	90	% CONTROL
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	T147-30464-00060	6/27/2012	TWO (2) STORAGE PILES		300000	TONS EACH	Particulate matter, total< 2.5 Âµ (TPM2.5)	WET SUPPRESSION WITH PILE COMPACTION	90	% CONTROL
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	T147-30464-00060	6/27/2012	TWO (2) STORAGE PILES		300000	TONS EACH	Particulate matter, filterable (FPM)	WET SUPPRESSION WITH PILE COMPACTION	90	% CONTROL
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	181-32081-00054	4/16/2013	MIXING AREA MATERIAL HANDLING SYSTEM		780	T/H	Particulate matter, total< 10 Âµ (TPM10)	BAGHOUSE CE011	0.002	GR/DSCF
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	181-32081-00054	4/16/2013	MIXING AREA MATERIAL HANDLING SYSTEM		780	T/H	Particulate matter, total< 2.5 Âµ (TPM2.5)	BAGHOUSE CE011	0.002	GR/DSCF
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	181-32081-00054	4/16/2013	MIXING AREA MATERIAL HANDLING SYSTEM		780	T/H	Particulate matter, filterable (FPM)	BAGHOUSE CE011	0.002	GR/DSCF
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-740	5/24/2010	PIL-101 - Coal Storage Piles		5512	T/h	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site.	1.48	LB/H
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-740	5/24/2010	PIL-102 - Iron Ore Pellet Storage Piles		5512	tons per hour	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site.	5.61	LB/H
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-740	5/24/2010	PIL-103 - Flux Storage Piles		1323	T/H	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site	1.98	LB/H
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-740	5/24/2010	PIL-104 - Pig Iron Storage Piles		1102	t/h	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site.	0.27	LB/H

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LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-740	5/24/2010	PIL-105 - Granulated Slag Storage Piles		661	T/H	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site	1.56	LB/H
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-740	5/24/2010	PIL-106 - Sinter Storage Piles		661	T/H	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site	1.15	LB/H
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-740	5/24/2010	PIL-107 - Coke Breeze Storage Piles		661	t/h	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site.	0.51	LB/H
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-740	5/24/2010	PIL-108 - Mill Scale Storage Piles		661	T/H	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site	0.65	LB/H
*LA-0345	DIRECT REDUCED IRON FACILITY	NUCOR STEEL LOUISIANA LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-751(M3)	6/13/2019	bulk materials storage piles and handling		0		Particulate matter, total< 2.5 Âµ (TPM2.5)	Wet suppression and minimizing the handling	0	
*LA-0345	DIRECT REDUCED IRON FACILITY	NUCOR STEEL LOUISIANA LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-751(M3)	6/13/2019	bulk materials storage piles and handling		0		Particulate matter, filterable< 10 Âµ (FPM10)	Wet suppression and minimizing the handling	0	
*LA-0345	DIRECT REDUCED IRON FACILITY	NUCOR STEEL LOUISIANA LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-751(M3)	6/13/2019	material transfers and conveyors		0		Particulate matter, total< 10 Âµ (TPM10)	baghouses and/or enclosed conveyors	0	
*LA-0345	DIRECT REDUCED IRON FACILITY	NUCOR STEEL LOUISIANA LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	PSD-LA-751(M3)	6/13/2019	material transfers and conveyors		0		Particulate matter, total< 2.5 Âµ (TPM2.5)	baghouses and/or enclosed conveyors	0	
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	OHIO ENVIRONMENTAL PROTECTION	P0104768	2/9/2010	Storage Piles, coal and coke		839500	T/YR	Particulate matter, filterable (FPM)		7.51	T/YR
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	OHIO ENVIRONMENTAL PROTECTION	P0104768	2/9/2010	Storage Piles, coal and coke		839500	T/YR	Particulate matter, filterable< 10 Âµ (FPM10)		3.64	T/YR
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	OHIO ENVIRONMENTAL PROTECTION	P0104768	2/9/2010	Storage Piles, coal and coke		839500	T/YR	Particulate matter, filterable< 2.5 Âµ (FPM2.5)		1.29	T/YR
OK-0173	CMC STEEL OKLAHOMA	COMMERCIAL METALS COMPANY	OK	OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY	2015-0643-C PSD	1/19/2016	Storage Piles : Refractory and Slag		0		Particulate matter, total (TPM)	One BACT determination for outdoor material piles: minimizing drop height. In addition, use of windbreaks and watering of piles may be used, although watering may result in unacceptable solidification of slag or other materials discharged from high-temperature operations. Most of the outdoor piles materials are scrap steel which has very little brittle materials susceptible to becoming fugitive dust.	0	

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	AGENCY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
TX-0822	CEMENT PLANT	CAPITOL AGGREGATES, INC.	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7369, PSDTX120M4, AND GHGPSDTX	6/30/2017	Material Handling, Transport, and Transfer Sources		0		Particulate matter, total (TPM)	BAGHOUSE	0.01	GR/DSCF
TX-0822	CEMENT PLANT	CAPITOL AGGREGATES, INC.	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7369, PSDTX120M4, AND GHGPSDTX	6/30/2017	Material Handling, Transport, and Transfer Sources		0		Particulate matter, total< 10 Âµ (TPM10)	BAGHOUSE	0.01	GR/DSCF
TX-0822	CEMENT PLANT	CAPITOL AGGREGATES, INC.	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7369, PSDTX120M4, AND GHGPSDTX	6/30/2017	Material Handling, Transport, and Transfer Sources		0		Particulate matter, total< 2.5 Âµ (TPM2.5)	BAGHOUSE	0.01	GR/DSCF
TX-0828	PORTLAND CEMENT PLANT	TXI OPERATIONS LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	5933, PSDTX63M4, O1120	11/7/2017	Non-metallic mineral processing, Raw material handling operations and storage piles		0		Particulate matter, total (TPM)	WATER SPRAYS AND FULL/PARTIAL ENCLOSURES	0	
TX-0828	PORTLAND CEMENT PLANT	TXI OPERATIONS LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	5933, PSDTX63M4, O1120	11/7/2017	Non-metallic mineral processing, Raw material handling operations and storage piles		0		Particulate matter, total< 10 Âµ (TPM10)	WATER SPRAYS AND FULL/PARTIAL ENCLOSURES	0	
TX-0828	PORTLAND CEMENT PLANT	TXI OPERATIONS LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	5933, PSDTX63M4, O1120	11/7/2017	Non-metallic mineral processing, Raw material handling operations and storage piles		0		Particulate matter, total< 2.5 Âµ (TPM2.5)	WATER SPRAYS, FULL/PARTIAL ENCLOSURES	0	
*TX-0866	PORTLAND CEMENT PRODUCTION PLANT	TEXAS LEHIGH CEMENT COMPANY LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	PSDTX1552, GHGPSDTX189	10/24/2019	MATERIAL HANDLING		0		Particulate matter, filterable (FPM)	BAGHOUSE	0.0044	GR/DSCF
*TX-0866	PORTLAND CEMENT PRODUCTION PLANT	TEXAS LEHIGH CEMENT COMPANY LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	PSDTX1552, GHGPSDTX189	10/24/2019	MATERIAL HANDLING		0		Particulate matter, filterable< 10 Âµ (FPM10)	BAGHOUSE	0.0044	GR/DSCF
*TX-0866	PORTLAND CEMENT PRODUCTION PLANT	TEXAS LEHIGH CEMENT COMPANY LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	PSDTX1552, GHGPSDTX189	10/24/2019	MATERIAL HANDLING		0		Particulate matter, filterable< 2.5 Âµ (FPM2.5)	BAGHOUSE	0.0044	GR/DSCF

APPENDIX B. NO_X CONTROL COST CALCULATIONS

Table B-1. Baseline Emissions

Pollutant	Plant Site Emission Limits (tons/year)					Actual Emissions (tons/year)				
	North Boiler	South Boiler	Space Heater	Aggregate Insignificant/ Additional	Storage Piles	North Boiler [1,2]	South Boiler [1,2]	Space Heater	Aggregate Insignificant/ Additional	Storage Piles [3]
NO_X	233.73	233.73	5.99E-03	--	--	131.09	166.01	--	--	--
PM_{10}	7.10	7.20	--	14.50	2.20	4.67	3.94	--	--	1.39
SO_2	10.88	15.58	2.13E-01	--	--	7.39	10.42	--	--	--

[1] Operating data for the north and south boilers are based on CEM data as follows:

	North Boiler	South Boiler
Hours/Year	6,041	6,049

[2] SO_2 lb/hr emission rate determined using the annual average per CEMS 2019 data. NOx and PM_{10} use source test results to determine the lb/1000 lb steam emission factor as measured in 2015 and 2019, respectively. A factor of 0.74 is used to convert PM to PM_{10}, consistent with the methods specified in the facility permit. The following steam values are used for 2019:

	North Boiler	South Boiler
Mlb Steam	971,000	968,000

[3] Actual emissions from the storage piles is determined base on the 2019 actual report submission.

Table B-2. Cost Analysis Supporting Information for Tail-end SCR

Parameter	North Boiler	South Boiler	Units	Note(s)
Heat Input Capacity	249	249	MMBtu/hr	1
Potential NOx Emission Factor	0.174	0.220	lb/MMBtu	1
Potential NO_x Emissions	131	166	tpy	1
Removal Efficiency	90	90	%	2
Pollutant Removed @ % control	118	149	tpy	3
NOx Removal Factor (NRF)	1.13	1.13		4
SCR Inlet Airflow (before reheating)	100,187	102,558	acfm	1
SCR Inlet Temperature (before reheating)	303	312	° F	1
SCR Inlet Temperature (after reheating)	700	700	° F	5
SCR Inlet Flow Rate	314,036	317,676	lb/hr	6
Additional heat required	99.19	96.91	Btu/lb	7
	31	31	MMBtu/hr	
	272,853.10	269,691.34	MMBtu/yr	8
Natural Gas Cost	0.27	0.27	$/MMBtu	1
Fuel Sulfur Content	0.01	0.01	%	1
Ammonia Slip Allowed	2	2	ppm	9
Mass Flow Rate of Reagent	15.18	19.20	lb/hr	4
Concentration of Stored Reagent Solution	19	19	% Reagent	9
Pressure Drop Across the SCR and Ductwork	7.5	7.5	inches of H_2O	9
Electricity Usage	138	138	kW	4
Number of Hours of Operator Labor	4	4	hrs/day	9
Labor Rate (Including Benefits)	$37.93	$37.93	$/hr	1
Catalyst Cost, Initial	254.57	254.57	$/ft^3	9
Catalyst Cost, Replacement	254.57	254.57	$/ft^3	9
19% Ammonia Solution Cost	0.04	0.04	$/lb	9
Electricity Cost	0.045	0.045	$/kW-hr	1
SCR Equipment Life	20	20	years	10
Interest Rate	4.75%	4.75%	%	10
2016 $	541.7	541.7	n/a	11
2019 $	607.5	607.5	n/a	11

[1] Site- and unit-specific values for the Biomass One Boilers

[2] Conservatively uses the highest level of control from the EPA's Air Pollution Control Technology Fact Sheet for Selective Catalytic Reduction (SCR) https://www3.epa.gov/ttncatc1/cica/files/fscr.pdf

[3] Pollutant Removed (tpy) = (Removal Efficiency, %) × (Potential Emissions, tpy).

[4] EPA Air Pollution Control Cost Manual, Section 4, Chapter 2, "Selective Catalytic Reduction." https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

[5] Flue gas reheat temperature based on Figure 2.2 of the EPA Air Pollution Control Cost Manual, Section 4, Chapter 2, "Selective Catalytic Reduction." https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

[6] Assumes the density of the exhaust is that of air at standard temperature and presssure, based on air density information from the NIST Physical Measurement Laboratory, https://pml.nist.gov/cgi-bin/Star/compos.pl?refer=ap&matno=104

Density: 0.075 lb/ft^3

[7] An average heat capacity of 0.2498 Btu/lb-F is used to calculate the heat needed to raise the temperature of flue gas. https://www.ohio.edu/mechanical/thermo/property_tables/air/air_Cp_Cv.html

[8] Calculations assume 8,760 hours of operation per year.

[9] Default value used in examples in the EPA Air Pollution Control Cost Manual, Section 4, Chapter 2, "Selective Catalytic Reduction." https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

[10] Default values specified in the Oregon Department of Air Qualitiy's "Regional Haze: Four Factor Analysis Fact Sheet." Due to substantial fluctuations and uncertainty in bank prime rates resulting from the evolving COVID-19 situation, the interest rates used at the date of the fact sheet's publication are used because they are likely more representative of future anticipated interest rates.

[11] Values based on Chemical Engineering's Plant Cost Index (CEPCI) https://www.chemengonline.com/site/plant-cost-index/

Table B-3. Cost Analysis for SCR

Capital Cost	North Boiler	South Boiler	EPA Cost Manual SCR Section Equation [2]	Notation
Total Capital Investment	5,316,814	5,316,814	2.53	$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$
Direct Annual Costs				
Operating and Supervisory Labor	55,378	55,378		OSL
Annual Maintenance Cost	26,584	26,584	2.57	AMC
Annual Reagent Cost	21,153	26,789	2.58	ARC
Annual Electricity Cost	37,421	37,470	2.61	AEC
Annual Catalyst Cost[1]	973,118	973,118	2.67	ACC
Annual Air Reheat Natural Gas Cost	73,688	72,834		ANGC
Total Direct Annual Costs	*1,187,342*	*1,192,174*	*2.56 (modified)[3]*	*DAC = OSL + AMC + ARC + AEL + ACC + ANGC*
Indirect Annual Costs				
Administrative Charges	1,693	1,693	2.69	AC
Capital Recovery	417,638	417,638	2.7, 2.71	CR
Total Indirect Annual Costs	*419,331*	*419,331*	*2.68*	*IDAC = AC + CR*
Total Annual Cost	**1,606,673**	**1,611,505**	**2.72**	*TAC = DAC + IDAC*
Pollutant Removed (tpy) @ % control	118	149		tpy
Pollutant Generated from Natural Gas Combustion (tpy)[4]	4	4		tpy
Cost per ton of NO_X Removed @ % control	**14,131**	**11,100**	**2.73**	*$/ton = TAC / (Pollutant Removed-Pollutant Generated)*

[1] Catalyst replacement cost assumes 24,000 hours of operational life and 8760 hours per year of SCR operation.

[2] EPA Air Pollution Control Cost Manual, Section 4, Chapter 2, "Selective Catalytic Reduction." https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

[3] Modified equation 2.56 to account for labor costs and the cost to reheat the flue gas for a tail-end SCR application.

[4] NO_X emissions from natural gas combustion are calculated using emission factors published in EPA's AP-42 emission factors, Table 1.4-1: "Emisison Factors for Nitrogen Oxides (NO_X) and Carbon Monoxide (CO) from Natural Gas Combustion."

The emission factor for controlled small boilers is conservatively used, as it is the lowest rate of emissions: 32 lb/MMscf

Emission factors in AP-42 are developed using the following factor, for conversion: 1,020 Btu/scf