

PROJECT REPORT
Weyerhaeuser > Columbia Falls and Evergreen Facilities

**Regional Haze 2nd Planning Period
Four-Factor Analysis**

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1. EXECUTIVE SUMMARY

Weyerhaeuser Company (Weyerhaeuser) operates facilities in Evergreen, MT and Columbia Falls, MT. This report represents Weyerhaeuser's response to a request by the Montana Department of Environmental Quality, Air Quality Bureau (DEQ) for a four-factor analysis of additional control technologies that may be implemented at the Evergreen and Columbia Falls facilities for the reduction of nitrogen oxide (NO_x) emissions. DEQ also specified that visibility modeling is not required for this analysis, and thus modeling is not performed. The Regional Haze Rule (RHR) covers emissions of pollutants that can affect visibility, including particulate matter (PM), sulfur dioxide (SO₂), and NO_x. Control evaluations for emissions of PM and SO₂ are not included in this response because DEQ requested a review of only NO_x. DEQ's screening process eliminated PM and SO₂ as pollutants of concern for these facilities. The four-factor analysis consists of the following factors for each pollutant and control technology:

- Factor 1. Cost of Compliance
- Factor 2. Time Necessary for Compliance
- Factor 3. Energy and Non-Air Quality Environmental Impacts
- Factor 4. Remaining Useful Life of Any Potentially Affected Source

These factors are considered throughout this report, which is made up of the following sections:

- Section 2: Introduction and Background
- Section 3: NO_x Control Technology Descriptions
- Section 4: Control Technology Analysis for NO_x from the Riley Stoker Boilers
- Section 5: Control Technology Analysis for NO_x from the Line 2 MDF Fiber Dryers
- Section 6: Control Technology Analysis for NO_x from the Line 1 MDF Fiber Dryers
- Section 7: Conclusion
- Attachment A: MT DEQ Reasonable Progress Analysis Request Letter
- Attachment B: RBLC and Biomass Boiler Permit Search Results
- Attachment C: SCR Cost Estimate for Boilers and Dryers
- Attachment D: Process Flow Diagram of Line 1 and Line 2 Dryers

The report identifies the following potential NO_x control technologies for the Weyerhaeuser boilers and dryers:

Riley Stoker Boilers NO_x Emission Reduction Options

- SCR: Technical challenges of using selective catalytic reduction (SCR) for NO_x emission reduction for the Riley Stoker boilers include managing gas stream temperature and catalyst effectiveness; therefore, SCR is determined to be technically infeasible. Cost calculations are included for thoroughness.
- SNCR: Selective non-catalytic reduction (SNCR) is determined technically infeasible because the boiler has no locations with temperatures within the temperature window required for the reaction.
- Staged Combustion: Implementing staged combustion technology presents numerous challenges, including injection port location limitations, flame impingement, and possible damage to the unit's structural integrity. Weyerhaeuser determined staged combustion to be technically infeasible for the Columbia Falls and Evergreen facilities' Riley Stoker boilers during the first planning period, and the control technology remains technically infeasible.

Line 2 MDF Fiber Dryers NO_x Emission Reduction Options

- SCR: Hot-side SCR technology is determined technically infeasible due to reactions between ammonia in the flue gas and formaldehyde in product resin. Tail-end SCR technology has also not been demonstrated on

wood products dryers due to technical constraints and is determined technically infeasible. Cost calculations are provided for thoroughness, and the technology is also cost ineffective.

- SNCR: The application of SNCR technology to wood products dryers raises challenges with both achieving ideal temperatures for reactions to occur and product damage from reactions between ammonia in flue gas and formaldehyde in product resin. Therefore, SNCR is determined to be technically infeasible.

Line 1 MDF Fiber Dryers NO_x Emission Reduction Options

- Staged Combustion / Low NO_x Burners: The size of the Line 1 MDF Fiber Dryers' combustion chamber is too small for the application of staged combustion. It is technically possible to replace the combustion chamber with one of a larger size, which would also require locating the chamber farther away from the dryer. Considering the cost of replacing the combustion chamber, the application of staged combustion cost ineffective.
- SCR: Hot-side SCR technology is determined technically infeasible due to reactions between ammonia in the flue gas and formaldehyde in product resin. Tail-end SCR technology has also not been demonstrated on wood products dryers due to technical constraints and is determined technically infeasible. Cost calculations are provided for thoroughness, and the technology is also cost ineffective.
- SNCR: The application of SNCR technology to wood products dryers raises challenges with both achieving ideal temperatures for reactions to occur and product damage from reactions between ammonia in flue gas and formaldehyde in product resin. Therefore, SNCR is determined to be technically infeasible.

All potential control technologies are deemed technologically or economically infeasible.

2. INTRODUCTION AND 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 6000 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 state¹. In establishing a reasonable progress goal for a Class I area, the state must:

- (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. 40 CFR 51.308(d)(1)(i)(A).*
- (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 measures needed to achieve it for the period covered by the implementation plan. 40 CFR 51.308(d)(1)(i)(B).*

There are a few key distinctions between the second national regional haze planning period, which is currently underway, and the first planning period. Most notably, analysis for the second planning period will distinguish between natural and anthropogenic sources. Using a Photochemical Grid Model (PGM), the EPA will establish both episodic and routine background concentrations to compare against anthropogenic source contributions.

DEQ is partnering with the Western Regional Air Partnership (WRAP) to develop modeling to demonstrate and ensure that reasonable progress is being made towards the reduction of visibility impairment in federal Class I areas. This will aid to support of the development of a State Implementation Plan (SIP) for the second planning period for the federal RHR, and follow the guideline laid out in Title 40 of the Code of Federal Regulations (40 CFR) 51.308(d)(1) and 40 CFR 51.308(d)(3).

On April 19, 2019, Montana DEQ sent a letter to Weyerhaeuser requesting that they assist in “developing information for the reasonable progress analysis” for Weyerhaeuser’s Evergreen and Columbia Falls facilities². The purpose of this report is to provide information to the DEQ and the Western Regional Air Partnership

¹ After initially withdrawing efforts to adopt a state implementation plan (SIP) in 2006, the Montana Department of Environmental Quality (MDEQ) operated under a Federal Implementation Plan (FIP) developed by the EPA through 2018. MDEQ is now transitioning back to an SIP for addressing the requirements for regional haze under 40 CFR 51.308.

² Refer to letter from Montana DEQ to Weyerhaeuser dated April 19, 2019.

(WRAP) regarding NO_x emission reductions that the facilities could achieve if the emission reductions are determined by WRAP to be necessary to meet the reasonable progress goals. DEQ requested a review of only NO_x because DEQ's screening process eliminated PM and SO₂ as pollutants of concern for these facilities. Control options are only relevant for the RHR if they result in a reduction in the existing visibility impairment in a Class I area. Therefore, Weyerhaeuser assumes that DEQ will only move forward with requiring emission reductions from the boilers and dryers if the emission reductions are demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ.

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 any potentially affected source

Factors 1 and 3 (cost of compliance and energy and non-air quality environmental impacts of compliance) of the four factors listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion. This is similar to the top-down approach that is included in the EPA RHR guidelines³ for conducting a review of Best Available Retrofit Technology (BART) for a unit⁴. 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 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. Step 4 of this report summarizes the conclusions of all four factors for clarity of completeness.

³ The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

⁴References to BART and BART requirements in this analysis should not be construed as an indication that BART is applicable to the Weyerhaeuser facilities.

3. NO_x CONTROL TECHNOLOGY DESCRIPTIONS

This section contains a detailed description of each NO_x control technology discussed in later sections of the report. While the working mechanism of these technologies in NO_x removal is highlighted, the unit-specific applications of these options are discussed in Sections 4 through 6. The control technologies are classified based on whether they are post-combustion controls or combustion modifications that are pollution-preventive by design.

3.1. BACKGROUND ON POLLUTANT FORMATION

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.⁵

“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.⁶

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.⁷

Nitrogen oxide (NO) formation is inherent in all high temperature combustion processes. Nitrogen dioxide (NO₂) 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 NO₂ 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 NO₂, as is the case in this report.

3.2. COMBUSTION MODIFICATION TECHNOLOGIES

The control technologies for combustion modification described below decrease NO_x emissions by preventing NO_x formation during the combustion process, rather than by reducing NO_x concentrations in the exhaust.

⁵ 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.

⁶ 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>.

⁷ 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>.

3.2.1. 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).

3.2.2. 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.

3.2.3. Low NO_x Burners (LNB)

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.

3.2.4. 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.

3.2.5. 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 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.

3.3. POST-COMBUSTION CONTROLS

The post-combustion control technologies described in detail below include Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), which both reduce NO_x in the flue gas by converting the NO_x to N_2 and H_2O .

3.3.1. Selective Catalytic Reduction (SCR)

The SCR technique involves injecting a reagent (ammonia or urea) into flue gas with a temperature in the range of 480 to 800°F, then passing the gas through a catalyst bed where NO_x is converted to N₂ and H₂O. The function of the catalyst is to lower the activation energy of the NO decomposition reaction, which lowers the temperature necessary to carry out the reaction. Depending on the location of the SCR system in the combustion flue gas path, SCR technologies can be tail-end (Cold-side) or high-dust (Hot-side). A high-dust SCR system is placed between the economizer and air heater, while the tail-end SCR is located downstream of the particulate control and air heater.

Babcock Power's patented Regenerative SCR (RSCR) systems are "Tail-end" SCR systems on the cold side, after the particulate control device. In the RSCR configuration, the reagent is first introduced upstream of the RSCR unit. The flue gas/reagent mixture (previously cleaned of particulate matter) then enters one end of the system, where the flue gas mixture travels up through the (hot) ceramic heat retention canister to be reheated. The flue gas mixture then flows through the catalyst section, where the ammonia reacts with the NO_x to form nitrogen and water. After the catalyst, the flue gas flows through a "retention" chamber, where a burner reheats the flue gas slightly. From this chamber, the flue gas then flows through the (cold) second canister and is used to heat this canister's ceramic heat retention block. Once this cycle is complete, the air flow is diverted, so that the second canister is the inlet for the "cold" flue gas, and the first canister is the outlet for the cleaned flue gas.⁸ The RSCR approach minimizes the supplemental fuel required to reheat the cold exhaust gas.

3.3.2. Selective Non-Catalytic Reduction (SNCR)

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 N₂ and water without the use of a catalyst.⁹ 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 NH₃ 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 NH₃ will become present in the exhaust.

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.

⁸ Abrams, Richard F. (Babcock Power Environmental, Inc.) and Kevin Toupin (Riley Power, Inc.). *Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Marketplace*. Worcester, MA: Babcock Power Environmental, Inc. March 2007. <http://www.babcockpower.com/pdf/t-200.pdf>

⁹ EPA, Air Pollution Control Technology Fact Sheet, EPA-452/F-03-031, Selective Non-Catalytic Reduction (SNCR), dated July 15, 2003.

4. CONTROL TECHNOLOGY ANALYSIS FOR NO_x FROM THE RILEY STOKER BOILERS (COLUMBIA FALLS AND EVERGREEN)

The Riley Stoker Boiler at *Columbia Falls* Operations was installed in 1973. It supplies steam to the refiners and MDF platen press. The boiler is rated at 292 MMBtu/hr and 170,000 pounds per hour (lb/hr) steam. The boiler's average firing rate from 2017 to 2018 was 111 MMBtu/hr.

The Riley Stoker Boiler at the *Evergreen Division* facility was installed in 1971. The boiler is rated at 196 MMBtu/hr and 140,000 lb/hr steam. It supplies steam for process operations such as the dry kilns, the veneer dryers, plywood presses, and the medium density overlay (MDO) press. The boiler's average firing rate from 2017 to 2018 was 96 MMBtu/hr.

The Riley Stoker Boilers at the Columbia Falls Operations and Evergreen Division facility are similar in design. Both are spreader-stoker boilers that combust wood residue, primarily as bark from each facility's log debarking process, and both are load-following boilers, meaning their firing rates are adjusted to meet the changing steam demand of various process operations. Sanderdust burners supplement the hog fuel firing downstream of the spreader-stoker grate in both boilers. The sanderdust burners are also capable of firing natural gas, with a design capacity of approximately 10 percent of the total boiler capacity. Natural gas firing only occurs during startup and rare events of sanderdust shortage. For reasons of similarity in design and operation, the control technology evaluations for both the Columbia Falls and Evergreen units are addressed in this section.

The firing rate varies for the Riley Stoker Boilers at the Columbia Falls Operations and at the Evergreen Division facilities in order to meet the steam demand at the respective facilities. The load of the Columbia Falls Operations Riley Stoker Boiler fluctuates between 50,000 lb/hr steam and 150,000 lb/hr steam, and the Evergreen Division Riley Stoker Boiler's load varies between 30,000 lb/hr steam and 70,000 lb/hr steam. These widespread load changes often occur rapidly, sometimes swinging from the minimum load to the maximum load within thirty minutes. The average low-end temperature of the flue gas from the boilers is 350° F.

4.1. STEP 1: IDENTIFY ALL AVAILABLE RETROFIT CONTROL OPTIONS

The potentially applicable NO_x control technologies are identified based on:

- A review of relevant information published in literature;
- Determinations for similar units identified from a search of the EPA RACT/BACT/LAER Clearinghouse (RBLC);
- A review of recently issued permits for similar biomass boilers (a summary of relevant RBLC and permit search results is presented in Attachment B); and
- Experience in conducting control technology reviews for similar types of equipment.

4.1.1. Discussion of Current Combustion Design and Available Combustion Modification Improvements

The Riley Stoker Boilers inherently use a process similar to fuel staging by design. The sanderdust burners, which typically supply approximately 10 percent of the heat to the boiler, are located downstream of the primary wood-fired flame. This configuration helps reduce thermal NO_x by breaking the combustion event into multiple stages. The formation of NO_x can be controlled using good combustion and boiler operation practices. Weyerhaeuser adheres to a robust maintenance program to maintain the boilers' burners, hog fuel feed system, fans, and other equipment in optimal condition. The boilers are also equipped with a computer control system used to maintain optimum air-to-fuel ratios and fuel feed rates. These good operating practices allow the

facilities to meet the NO_x permit limits for the Riley Stoker Boilers at the Columbia Falls Operations (134.50 lb/hr) and Evergreen Division facility (104 lb/hr).

Minimal thermal NO_x is formed in wood-fired spreader stoker boilers due to the high moisture content of the wood, and the spreader stoker firing configuration. Therefore, combustion modification technologies that are aimed at reducing thermal NO_x formation, such as FGR, are not considered. Additionally, combustion modification technologies used with traditional gas and oil burners, such as LNB, are not available for wood-fired boilers.¹⁰ Similarly, since the boilers are of spreader stoker design, they need high excess air levels for proper fuel burning.¹¹ As such, combustion modifications like LEA are not practical to employ on spreader stoker boilers.

Many wood-fired spreader stoker boilers include overfire air systems by design. The overfire air combustion configuration reduces NO_x through staged combustion technology. Because overfire air systems are commonly employed in spreader stoker boilers, retrofitting an overfire air system on Weyerhaeuser's Riley Stoker boilers has been identified as a combustion modification improvement option.

After accounting for the physical and operational characteristics of the Riley Stoker Boilers, the post-combustion and combustion modification control technologies and strategies considered in this analysis for controlling NO_x emissions include the following:

Combustion Modification Improvements

- Staged Combustion (OFA)
- Good Operating Practices (base case)

Post-Combustion Controls

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

Each of the technologies listed above are described in Section 3 of this report, with the exception of good operating practices for the Riley Stoker Boilers.

4.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The technical feasibility of each identified technology for control of NO_x emissions from the Riley Stoker Boilers is discussed in the following sections.

4.2.1. Selective Catalytic Reduction (SCR)

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

¹⁰ In wood-fired spreader stoker boilers such as those in the Weyerhaeuser facilities, the hog fuel is not fed using traditional burners. The majority of the wood residue fuel is fed on grates, and specialized sanderdust burners are used for up to 10 percent of the heat input capacity.

¹¹ Washington State Department of Ecology Publication No. 03-02-009, *Hog Fuel Boiler RACT Determination*, April 2003, <http://www.ecy.wa.gov/biblio/0302009.html>.

existing boiler fans. Third, the National Council for Air and Stream Improvement (NCASI) notes that 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.¹² In biomass boilers, plugging and fouling of the catalyst can occur due to large amounts of fly ash generated by the biomass.

The desired minimum temperature for SCR application to achieve 70% control is 575°F¹³. The maximum exhaust temperature of the Riley Stoker Boiler at Columbia Falls Operations is 500°F and the exhaust temperature for the boiler at the Evergreen Division facility is 430°F. While the exhaust temperatures of the two boilers are close to the range of operation of the SCR system, higher temperatures would be needed for optimum control efficiency for tail-end SCR application.

In an RSCR system, the regenerative heating reduces the required heat input; however, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation. Moreover, it is not considered available as RSCR has not been previously demonstrated on load-following industrial boilers. 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, the wide load swings experienced by the Weyerhaeuser boilers result in unstable exhaust temperatures and would make it particularly difficult to control the reagent injection rate needed to ensure appropriate NO_x reductions while avoiding excessive ammonia slip. For these reasons, SCR technology has not been successfully demonstrated for a load-following spreader-stoker boiler with load swings comparable to the Riley Stoker Boilers at the Columbia Falls Operations and Evergreen Division Facility.^{14,15}

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 a load-following spread-stoker boiler, are considered to be technically infeasible. Nevertheless, an economic analysis has been conducted on the boilers at the Weyerhaeuser facilities 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.

¹² NCASI Special Report 03-04, *NO_x Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

¹³ 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.

¹⁴ NCASI Corporate Correspondent Memorandum No. 06-014, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_x, SO₂ and PM Emissions*, June 2006.

¹⁵ A review of the RBLC database and of recently issued biomass boiler permits, performed in 2019, indicates that SCR technology has not been previously demonstrated on similar load-following boilers. Refer to Attachment B of the letter for a list of RBLC search results for biomass boilers.

4.2.2. Selective Non-Catalytic Reduction (SNCR)

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 load-following hog fuel boilers continues to pose several technical challenges. 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 3, high temperatures, normally between 1,600 and 2,100°F, promote the reaction between urea or ammonia and NO_x to form N₂ and water. In a load-following boiler, the region of the boiler where the optimal temperature range is present would vary depending on the firing rate, making it very difficult to control the SNCR reaction temperature. Modeling studies performed for the Columbia Falls and Evergreen Riley Stoker Boilers indicate that the boiler grate is the only location that reaches even the low end of this temperature range. Therefore, no locations exist within the boilers with high enough temperature for SNCR to be technically feasible.¹⁶

Another factor preventing proper implementation of SNCR technology in load-following biomass boilers is inadequate reagent dispersion in the injection region, which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (i.e., large ammonia slip). At least one pulp mill wood-fired boiler had to abandon their SNCR system due to problems caused by poor dispersion of the reagent within the boiler.¹⁷

SNCR has yet to be successfully demonstrated for a hog fuel boiler with swing loads comparable to the Riley Stoker Boilers at the Columbia Falls Operations and Evergreen Division facilities. Therefore, SNCR is considered to be technically infeasible.¹⁸

4.2.3. Staged Combustion

Implementing staged combustion technology would require installation of OFA injection ports, which poses several site-specific technical obstacles for Weyerhaeuser's Riley Stoker Boilers. The ports would need to be installed at the exact location where the current sanderdust burners are located, and installing OFA in the boilers' small combustion chambers would likely result in flame impingement on boiler walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions.¹⁹ Staged combustion generally lengthens the flame configuration so the applicability is limited to installations large enough to avoid flame impingement on internal surfaces.²⁰

¹⁶ Thermal profile models provided in a Phase 1 Engineering Evaluation performed by Jansen Combustion and Boiler Technologies, Inc. in August 2012.

¹⁷ NCASI Corporate Correspondent Memorandum No. 06-014, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_x, SO₂ and PM Emissions*, June 2006.

¹⁸ A review of the RBLC database and of recently issued biomass boiler permits, performed in September 2019, indicates that SNCR technology has not been previously demonstrated on similar load-following boilers. SNCR installations are identified for three industrial biomass boilers. However, each of the boilers with SNCR does not operate under load-following conditions comparable to the Weyerhaeuser Riley Stoker Boilers. The RBLC search results indicate that the SNCR installations are only on biomass boilers located at lumber mills, which do not experience the same fluctuations in steam demand that Weyerhaeuser and other wood product mills experience. Further detail for each SNCR application is provided in Attachment B.

¹⁹ NCASI Special Report 03-04, *NO_x Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

²⁰ Sloss, Leslie L. Nitrogen oxides technology fact book. 1992.

Other issues related to general OFA retrofit installations include penetration of the boiler walls, which may affect the structural integrity of the unit, and which would require re-routing of the steam tubes. The reducing atmosphere created in the fuel-rich primary combustion zone may also result in accelerated corrosion of the furnace. Additionally, grate corrosion and overheating may occur in stokers as primary air flow is diverted to overfire air ports.²¹

Retrofitting the Riley Stoker Boilers with OFA injection ports is not technically feasible due to the numerous technical issues described above. Therefore, OFA technology is considered to be technically infeasible and is not considered further in the analysis.

4.3. STEP 3: EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

4.3.1. Selective Catalytic Reduction (SCR)

An economic analysis is conducted on the boilers at the Weyerhaeuser facilities to further demonstrate the infeasibility of the tail-end SCR application on the boilers. Higher NO_x reduction efficiencies can be achieved if the flue gas is reheated to a higher temperature (to the optimum level); therefore, a range of control efficiencies are evaluated. As summarized in Table 4.1 and 4.2, the cost of reheating the flue gas alone makes this technology cost ineffective at both the Columbia Falls and Evergreen Division facilities, regardless of the control efficiency target of the system. For detailed cost calculations, please refer to Attachment C of this report.²²

Table 4.1 Cost Effectiveness of Emissions Reduction: Columbia Falls

Control Option	Cost of Reheating Flue Gas (\$/yr)	Total Annual Cost of SCR (\$/yr)	Baseline Emission Level (tpy)	Emission Reduction (tpy)	Cost Effectiveness (\$/ton removed)
70% Control	\$356,823	\$1,144,194	587	411	\$2,785
80% Control	\$594,704	\$1,385,905	587	470	\$2,952
90% Control	\$951,527	\$1,746,556	587	528	\$3,306

²¹ Controlling Nitrogen Dioxides under the Clean Air Act, A Menu of Options: Industrial and Commercial Boilers, <http://www.p2pays.org/ref/02/01245/3017103.pdf>

²² Note that multiple control efficiencies were requested from the vendor, but costs for only the 90% control efficiency case were provided. The cost estimates for 70% and 80% control provided in Attachment C are based on applying general assumptions regarding the capital cost break-down (50% fixed, 50% linearly proportional to control efficiency) for the 90% control efficiency case.

Table 4.2 Cost Effectiveness of Emissions Reduction: Evergreen

Control Option	Cost of Reheating Flue Gas (\$/yr)	Total Annual Cost of SCR (\$/yr)	Baseline Emission Level (tpy)	Emission Reduction (tpy)	Cost Effectiveness (\$/ton removed)
70% Control	\$421,277	\$999,961	587	162	\$8,815
80% Control	\$566,545	\$1,146,142	587	162	\$8,840
90% Control	\$784,448	\$1,364,956	587	162	\$9,358

As discussed in Step 2 in previous paragraphs, the installation of an RSCR would pose significant design challenges in load-following boilers. An evaluation based on a vendor quote specific to an RSCR system is not available at this time.²³ For the purpose of an economic analysis, the cost to install an RSCR system is expected to be similar to that for a tail-end SCR system. From the cost evaluation, it can be concluded that there are economic constraints associated with installing a SCR control system. As such, RSCR and SCR are not cost effective.

4.4. STEP 4: EVALUATE IMPACTS

All control technology options are considered technically or economically infeasible for these boilers. Good combustion and boiler operation practices constitute the most suitable control option for the Riley Stoker Boilers.

4.4.1. Time Required to Achieve Control

Weyerhaeuser believes that reasonable progress compliant controls (good operating practices) are already in place. However, if DEQ determines that one of the NO_x reduction options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

4.4.2. Energy Impacts and Non-Air Quality Impacts

The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix C. To operate the control devices, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Reheating the flue gas for SCR application would also require substantial natural gas usage with an associated increase in direct emissions.

The use of NO_x reduction methods that incorporate ammonia injection leads to increased health risks to the local community from ammonia slip emissions. Additionally, there are safety concerns associated with the

²³ A quote for an RSCR system from Babcock Power Environmental Inc. was requested by Anna Henolson (Trinity) on 12/06/2011.

transport and storage of ammonia, including potential ammonia spills that can have serious adverse health impacts.

4.4.3. Remaining Useful Life

The remaining useful life of the equipment is used for evaluating economic feasibility and may need to be considered in establishing RP goals for the region. The remaining useful life of each Riley Stoker Boiler is 20 years or more.

5. CONTROL TECHNOLOGY ANALYSIS FOR NO_x FROM THE LINE 2 MDF FIBER DRYERS (COLUMBIA FALLS)

The Line 2 MDF Dryers at Columbia Falls Operations are direct-contact dryers. The flue gas from the combustion chamber, rated at 85 MMBtu/hr, feeds a two-stage flash tube dryer (the first stage dryer and the second stage dryer). The Line 2 Dryers are equipped with venturi scrubbers, followed by biofilters for particulate and VOC control. The burner that supplies the heat to the dryers is fired with sanderdust from the process and employs staged combustion to limit NO_x formation. A copy of the Process Flow Diagram for the Dryers is included in Attachment D.

5.1. STEP 1: IDENTIFY ALL AVAILABLE RETROFIT CONTROL OPTIONS

Potentially applicable NO_x control technologies are identified based on a review of determinations for similar units identified from the RBLC search (Attachment B presents a summary of the RBLC search results for the NO_x control technologies for MDF dryers). After accounting for the physical and operational characteristics of the Line 2 MDF Fiber Dryers, the control technologies and strategies considered in this analysis for controlling NO_x emissions include the following:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

The Line 2 MDF Fiber Dryers are currently equipped with staged combustion, and hence this control is treated as a baseline scenario against which additional control options are considered. Please refer to Section 3 of this report for a description of the control technologies listed above.

5.1.1. Discussion of Current Combustion Design and Available Combustion Modification Improvements

The combustion for the Line 2 MDF Fiber Dryers employs a staged combustion design.²⁴ First, the burners fire sanderdust at less than stoichiometric oxygen to fuel ratio. The primary combustion stage is "fuel rich", which limits formation of fuel NO_x. As the flame progresses in the firebox, additional air is added to complete the combustion process. Due to the lower temperature required in the secondary combustion zone, thermal NO_x formation is also reduced.

Most of the NO_x emissions from wood-fired units arise from the fuel nitrogen. As such, combustion modification technologies aimed at reducing thermal NO_x formation, such as FGR, are not considered. Since the dryers burn wood residue in a small combustion chamber with no available footprint for a secondary combustion zone, fuel staging is not an available combustion modification option (as the technology involves the diversion of fuel to a secondary combustion zone). Additionally, fuel staging primarily reduces thermal NO_x as opposed to fuel NO_x (the primary component of the dryers' exhaust). LEA is also not an available control alternative as high excess

²⁴ It should be noted that the Columbia Falls Operations air permit specifies that the Line 2 Dryers employ LNB/FGR; however, the technology employed in practice is staged combustion. The burners contribute to lower NO_x formation by firing the sanderdust at sub-stoichiometric conditions; however, the burners themselves do not support the secondary combustion stage needed to complete the combustion process. The unit does not employ any form of FGR. An RBLC search returns results for wood product dryers implementing LNB/FGR in the last ten years. As mentioned in 5.1.1, FGR is not considered because most of the NO_x emissions from the wood-fired boilers arise from fuel nitrogen.

air levels are needed for proper fuel burning in MDF dryers due to limited thermal decomposition of wood furnish components in the drying process. Therefore, no combustion modification improvements are identified for the Line 2 Dryers.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The technical feasibility of each identified technology for the control of NO_x from the Line 2 MDF Fiber Dryers is discussed in the following sections.

5.2.1. Selective Catalytic Reduction (SCR)

SCR technology has not been previously demonstrated on a wood product dryer. This control option does not appear in the RBLC search results for similar units. SCR technology is not technically feasible for wood products dryers because of the direct contact of the combustion air with the wood product material. If the reagent were to be injected in the optimal temperature range directly after the burner (hot-side SCR), the ammonia in the flue gas would deposit on the wood fibers (due to the direct-fired nature of the burners where the combustion gases come in contact with the material being dried), causing product damage. Specifically, the ammonia would tie up the formaldehyde in the urea-formaldehyde resin, altering the resin chemistry and causing structural defects. Furthermore, for a hot-side SCR, the SCR system is located prior to the particulate control processing. Such a design is technically difficult due to the small size of the combustion chamber. It also poses the risk of damage to the catalysts in the bed due to the large amount of particulates in the gas.

An alternative to avoid product fouling issues is to place the SCR system post particulate control (tail-end SCR). As mentioned previously, the Line 2 Dryers are currently equipped with venturi scrubbers followed by biofilters. For a tail-end SCR application, the flue gas from the dryers would need to be reheated to a temperature optimal for the injection of the ammonia reagent. The reheating cost alone is a significant hurdle in the application of this technology for these dryers.

The tail-end SCR can be located after the venturi scrubbers, prior to the biofilter. However, this system design would require a modification to the biofilters to accommodate increased flow and heat. A large volume of cooling air is added to the dryer exhaust stream prior to the biofilter in order to cool the flue gas to the biofilter's optimum temperature of 104 °F. Hence, the temperature is considerably lower and the flow is considerably higher post-biofilter. The size of the SCR system will also be significantly larger in such a scenario.

For the reasons mentioned above, SCR has not been successfully demonstrated on wood products dryers. Therefore, it is considered technically infeasible. However, a demonstration of the economic infeasibility of the tail-end SCR technology is included under Step 3 of this section.

5.2.2. Selective Non-Catalytic Reduction (SNCR)

As previously discussed, SNCR systems are installed where the temperature in the combustion zone of the unit reaches the optimum range for operation of the SNCR of 1600 to 2100 °F. The combustion zone for the Line 2 Dryers reaches a maximum temperature of approximately 1500 °F, which is lower than the minimum temperature needed for SNCR. Moreover, as for SCR, if the reagent were to be injected near the optimal temperature range within the combustion chamber, the reagent in the flue gas would deposit on the wood fibers and cause product damage (see reasoning in 5.2.1). Due to these reasons, SNCR has not been successfully demonstrated on wood products dryers. Therefore, SNCR is considered technically infeasible and is not considered further.

5.3. STEP 3: EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

5.3.1. Selective Catalytic Reduction (SCR)

For the purpose of an economic analysis, the cost to reheat the gas alone is evaluated for two tail-end SCR system locations – pre-biofilter and post-biofilter. The cost of reheating the flue gas alone for a SCR application placed post-biofilter is estimated at over \$103,000 per ton NO_x removed. For a scenario where the SCR system is placed prior to the biofilter, the flue gas reheating cost alone is estimated at over \$31,000 per ton NO_x removed. The biofilter would also need to be modified and expanded, adding additional capital and operating costs. For detailed calculations, refer to Attachment C. From the cost evaluation, it is clear that SCR is cost prohibitive. As such, this technology is economically infeasible.

5.3.2. Staged Combustion

Staged combustion technology, presently installed and operational, is an available NO_x control for the Line 2 Dryers. There are no other control options that are both technically and economically feasible.

5.4. STEP 4: EVALUATE IMPACTS

Staged combustion constitutes the most suitable control option for the Line 2 MDF Fiber Dryers. Weyerhaeuser employs a robust maintenance program that keeps this technology effective at reducing NO_x emissions. The burner itself is also strictly controlled with a computer that monitors and controls fuel feed and combustion air, as well as monitoring combustion zone temperatures and fire brick temperatures.

5.4.1. Time Required to Achieve Control

Weyerhaeuser believes that reasonable progress compliant controls (staged combustion) are already in place; therefore, time required to achieve control is not applicable.

5.4.2. Energy Impacts and Non-Air Quality Impacts

The cost of energy required for successful operation of the SCR are included in the calculations, which can be found in detail in Appendix C. To operate the control devices, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Significant usage of natural gas would be necessary just for reheating the flue gas for SCR application.

The use of NO_x reduction methods that incorporate ammonia injection leads to increased health risks to the local community from ammonia slip emissions. Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills that can have serious adverse health impacts.

5.4.3. Remaining Useful Life

The remaining useful life of the dryers is not used for evaluating the economic feasibility of control options. All add-on control technology options are considered technically or economically infeasible for this unit. The remaining useful life of the equipment may need to be considered in establishing Reasonable Progress goals for the region. The remaining useful life of the Line 2 MDF Fiber Dryers is at least 20 years.

6. CONTROL TECHNOLOGY ANALYSIS FOR NO_x FROM THE LINE 1 MDF FIBER DRYERS (COLUMBIA FALLS OPERATIONS)

The Line 1 MDF Fiber Dryers at the Columbia Falls Operations include a core dryer and a face dryer, each installed with a sanderdust burner with a capacity of 50 MMBtu/hr for each unit. The dryers can process up to 57 tons/hr of bone-dry fiber. A copy of the Process Flow Diagram for the Dryers is included in Attachment D.

6.1. STEP 1: IDENTIFY ALL AVAILABLE RETROFIT CONTROL OPTIONS

Potentially applicable NO_x control technologies are identified based on a review of determinations for similar units identified from the RBLC search (a summary of relevant RBLC search results are presented in Attachment B). After accounting for the physical and operational characteristics of the Line 1 MDF Fiber Dryers, the control technologies and strategies considered in this analysis for controlling NO_x emissions include the following:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Staged Combustion / Low NO_x Burners (LNB)
- Good Operating Practices (baseline)

Each of the technologies listed above are described in Section 3 of this report, with the exception of good operating practices for the Line 1 MDF Fiber Dryers.

The formation of NO_x can be controlled using good operation practices. Weyerhaeuser adheres to a robust maintenance program for the Line 1 MDF Fiber Dryers. Maintaining the burners and other dryer equipment in good condition promotes proper combustion and supports good operating practices, including computer controlled optimization of air to fuel ratios and firing rates. The burners are also computer monitored for combustion zone temperatures.

6.1.1. Discussion of Current Combustion Design and Available Combustion Modification Improvements

The size of the combustion chambers in the Line 1 Dryers is approximately one-fourth that of the combustion chamber for the Line 2 Dryers. This size difference is a direct result of the Line 2 Dryers including a staged combustion design requirement from the permitting process of the second line. The staged combustion technology implemented on the Line 2 Dryers requires four times the space to complete the combustion process. FGR, fuel staging, and LEA are not available combustion modification options for the Line 1 Dryers for the same reasons outlined previously in 5.1.1 for the Line 2 MDF Fiber Dryers.

Because staged combustion technology has been demonstrated as a technically feasible combustion technology for the Line 2 dryers, retrofitting a staged combustion system on Weyerhaeuser's Line 1 Dryers has been identified as a combustion modification improvement option.

6.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The technical feasibility for applying staged combustion for the control of NO_x from the Line 1 MDF Fiber Dryers is discussed in the following section.

6.2.1. Staged Combustion / Low NO_x Burners (LNB)

The available technique for application of staged combustion / LNB technology for the combustion of sanderdust involves the same staged combustion process described for the Line 2 MDF Fiber Dryers. This technique involves firing the sanderdust at sub-stoichiometric levels at the burners, and adding air through separate air ports to complete the combustion process. The type of LNB technology that can be applied for natural gas or fuel oil combustion is not applicable for the combustion of sanderdust.

The application of staged combustion is limited by the longer and cooler flames produced as a consequence of improved air distribution control. The Line 1 MDF Fiber Dryers have a combustion chamber that is size-restricted. The firebox is one-fourth the size of that of the Line 2 MDF Fiber Dryers combustion chamber. The small size of the combustion chamber makes it impossible to retrofit the Line 1 MDF Fiber Dryers with a staged combustion technology.

It is possible (though cost prohibitive) to replace the existing Line 1 burners with an entirely new, larger firebox needed to accommodate staged combustion. The location of the current burners is restricted by the footprint size, so the larger combustion chambers would need to be relocated further away from the dryer, which would also involve adding significant ducting to accommodate the existing Line 1 Dryers footprint. See Step 3 for an economic evaluation of this option.

6.2.2. Selective Catalytic Reduction (SCR)

As described for the Line 2 Dryers in 5.2.1, there are several technical challenges of installing an SCR system in the MDF dryers. See Step 3 for an economic evaluation of this option.

6.2.3. Selective Non-Catalytic Reduction (SNCR)

As described in detail in Section 5 for the Line 2 Dryers, SNCR is technically infeasible for application on the MDF dryers due to inadequate combustion chamber temperatures and product fouling.

6.3. STEP 3: EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

6.3.1. Staged Combustion / Low NO_x Burners (LNB)

For the purpose of an economic analysis, the cost to install two new burners with a larger firebox for the Line 1 Dryers is evaluated. It is estimated that the cost of the equipment with ducting would be priced at approximately \$4,000,000 in 2009 (\$4,379,811 in 2018 dollars), resulting in a cost of \$4,751 per ton of NO_x removed.²⁵ As such, this technology is economically infeasible.

²⁵ Capital cost of new burners is estimated by Weyerhaeuser based on the Line 2 capital projects and bids. Cost per ton of NO_x removed is calculated based on 2017-2018 firing data and 23% control efficiency, based on the Line 2 Dryers design control efficiency (no source test data available).

6.3.2. Selective Catalytic Reduction (SCR)

As described for the Line 2 Dryers in Section 5, an economic evaluation of reheating flue gas in a tail end SCR system is conducted on the Line 1 Dryers, considering two different SCR locations. The flue gas reheating cost for an SCR application placed post-biofilter is estimated at over \$94,000 per ton NO_x removed. For a scenario where the SCR system is placed prior to the biofilter, the flue gas reheating cost alone is estimated over \$24,000 per ton NO_x removed. Additional cost for increasing the capacity of the biofilter due to increased heat and for the capital cost of the SCR equipment would result in a considerably higher cost per ton. For detailed calculations, refer to Attachment C of the report. Based on the cost evaluation, this technology is economically infeasible and is not considered further.

6.4. STEP 4: EVALUATE IMPACTS

Good combustion practices constitute the most suitable control option for the Line 1 MDF Fiber Dryers.

6.4.1. Time Required to Achieve Control

Weyerhaeuser believes that reasonable progress compliant controls (good combustion practices) are already in place. However, if DEQ determines that one of the NO_x reduction options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

6.4.2. Energy Impacts and Non-Air Quality Impacts

The cost of energy required for successful operation of the SCR are included in the calculations, which can be found in detail in Appendix C. To operate the control devices, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Significant usage of natural gas would be necessary just for reheating the flue gas for SCR application.

The use of NO_x reduction methods that incorporate ammonia injection leads to increased health risks to the local community from ammonia slip emissions. Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills that can have serious adverse health impacts.

6.4.3. Remaining Useful Life

The remaining useful life of the unit is not used for evaluating the economic feasibility of control options. However, the remaining useful life of the equipment may need to be considered in establishing Reasonable Progress goals for the region. The remaining useful life of the face burner and core burner on the Line 1 MDF Fiber Dryers are 20 years each.²⁶

²⁶ Engineering estimate by Weyerhaeuser, communicated to Trinity Consultants by Mitchell Leu, August 2019.

7. CONCLUSION

Weyerhaeuser conducted a control technology evaluation to address requirements under the Regional Haze Rule for Reasonable Progress goals and strategies. Based on the evaluation presented in this report, the existing control measures are the most suitable for NO_x emissions from the Riley Stoker Boilers at the Columbia Falls Operations and Evergreen Division facility, and the Line 1 and Line 2 MDF Fiber Dryers at the Columbia Falls Operations.

NO_x emissions from the Riley Stoker Boilers are controlled using good operating practices, including use of a computerized control system to optimize the air and fuel feed rates. Additionally, the firing of hog fuel with supplemental downstream sander dust burners results in low thermal NO_x formation. NO_x emissions from the Line 1 MDF Fiber Dryers are controlled using good operating practices, and the Line 2 MDF Fiber Dryers employ staged combustion technology to reduce NO_x formation. All available NO_x control technologies are determined to be technically or economically infeasible.

Should DEQ have any questions or require further information regarding the emission units or control technologies addressed in this report, Weyerhaeuser will work with DEQ to provide additional information to assist in establishing the Reasonable Progress goals and strategies for Montana.

APPENDIX A: MT DEQ REASONABLE PROGRESS ANALYSIS REQUEST LETTER



April 19, 2019

Sent electronically to: mitchell_leu@weyerhaeuser.com

Mitchell Leu
Environmental Manager
13710 Fnb Parkway
Omaha, Nebraska 68154

RE: Regional Haze Reasonable Progress Analysis

Dear Mr. Leu,

As you are aware, the Montana Department of Environmental Quality, Air Quality Bureau (AQB), is in the process of developing a State Implementation Plan (SIP) for the second implementation period of the federal Regional Haze program, which is codified at 42 U.S. Code §7491 – Visibility protection for Federal class I areas. This implementation period focuses on making reasonable progress toward national visibility goals by analyzing progress to-date from the 2000-2004 baseline and considering whether additional emission reductions are necessary to continue a reasonable rate of progress.

The reasonable progress analysis involves assessing potential emission control technology against four statutory factors, including cost of controls, time necessary to install controls, energy and non-air quality impacts, and remaining useful life. Through this process, DEQ is also working with the Western Regional Air Partnership (WRAP) to prepare regional air quality modeling of visibility conditions associated with current emissions, projected future emissions, and potential future control scenarios. DEQ will work with you to ensure the accuracy and representativeness of emissions data for modeling.

Now that we have completed initial calls and discussed the screening process for Weyerhaeuser NR (Weyerhaeuser) – Evergreen and Columbia Falls facilities, DEQ is formally requesting assistance from Weyerhaeuser in developing information for the reasonable progress analysis. For this information to be included in the regional modeling analyses, we request that it be submitted to DEQ no later than September 30, 2019.

The purpose of this letter is to provide additional clarification to help you prepare information associated with the reasonable progress analysis. We understand that confirming as many details as possible early in the analysis will reduce the chance of repeating or re-doing calculations later in the process. We hope these clarifications will help define the analysis, but please contact DEQ if you have any further questions.

In reviewing reasonable progress analyses, DEQ will rely on the following three resources to ensure accuracy and consistency. All information prepared as part of the reasonable progress analysis should be prepared using the guidance provided in these documents.

1. [EPA Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals, and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period \(“Draft Guidance”\)](#)ⁱ
2. [EPA Air Pollution Control Cost Manual \(“Control Cost Manual”\)](#)ⁱⁱ
3. [EPA Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM_{2.5}, and Regional Haze \(“Modeling Guidance”\)](#)ⁱⁱⁱ

Guidance for Developing Cost of Control Estimates for Reasonable Progress Analysis

For the requested reasonable progress analysis, a 20-year planning horizon should be assumed. The only exception to this horizon is if there is a unit shutdown date identified that will cease operations before 20 years has expired. Additionally, the generally accepted accuracy in the Control Cost Manual is within plus or minus 30%. Facilities using technical experts and consultants may have more accurate projections due to their previous hands-on experience. DEQ requests that you please explain any deviations from the 20-year planning horizon or the presumed 30% accuracy in your estimates.

The latest guidance from EPA points to the interest rate that is most appropriate for your facility based on previous project engineering experience at your facility. This most likely will result in the selection of an interest rate between 3% and 7%. In the absence of a more specific interest rate, EPA recommends that you use the current bank prime rate, which is 5.5% as of the date of this letter, as a default.^{iv}

DEQ also requests that capital and annual costs be estimated as if the project will be constructed at the time the cost estimate is prepared. The annualized cost of the project should be presented by annualizing the capital cost and adding that to the annual operating costs. Please also calculate the cost in dollars per ton of emission reduction for each evaluated control alternative by dividing the uniform annual cost by the tons of annual emission reduction anticipated.

Additional Guidance for Preparing Reasonable Progress Analyses

As part of the reasonable progress analysis, DEQ will consider additional information provided by a facility, including supplemental visibility modeling. This modeling is not required. In lieu of supplemental visibility modeling, DEQ will use the information provided by WRAP to assess visibility impacts from a facility. Please note, a visibility modeling demonstration can support but not replace the four-factor analysis described in this letter. If you choose to prepare your own modeling demonstration, DEQ requests that it be prepared in accordance with EPA’s modeling guidance cited above and [Appendix W](#) to Title 40, Part 51 of the Code of Federal Regulations.^v DEQ also requests the opportunity to review your modeling protocol to ensure consistency with EPA guidance.

Thank you in advance for your support in this analysis effort. Again, please submit any reasonable progress analysis information by September 30, 2019. We are working closely to meet regional timelines for visibility modeling and this due date will allow adequate time for review and discussion of the analysis in advance of regional deadlines. If you have any questions, please contact Rhonda Payne at 406-444-5287 or by email at repayne@mt.gov.

Sincerely,



Rebecca Harbage
Regional Haze Project Manager
Air Quality Bureau

Cc: Karen Wilson, AQB
David L. Klemp, Chief, AQB

ⁱ Environmental Protection Agency, “Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals, and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,” July 2016, EPA-457/P-16-001. https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf. EPA anticipates releasing a final version of the guidance in Spring 2019 and DEQ will contact you as soon as possible following its release if there are any major changes.

ⁱⁱ EPA, “EPA Air Pollution Control Cost Manual.” <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>. EPA is in the process of updating what will be the Seventh Edition of this document and some updates have already been finalized. Please refer to the most current finalized versions.

ⁱⁱⁱ EPA, “Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze,” November 2018, EPA-454/R-18-009. <https://www.epa.gov/scram/state-implementation-plan-sip-attainment-demonstration-guidance>.

^{iv} The current bank prime rate can be found on the Federal Reserve website: <https://www.federalreserve.gov/releases/h15/>.

^v EPA, “Appendix W to Part 51 – Guideline on Air Quality Models,” 40 CFR Part 51, Appendix W, July 1, 2018. <https://www.govinfo.gov/content/pkg/CFR-2018-title40-vol2/xml/CFR-2018-title40-vol2-part51-appW.xml>.

APPENDIX B: RBLC AND BIOMASS BOILER PERMIT SEARCH RESULTS

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	SIC CODE	NAICS CODE	COMPLETE APPLICATION DATE	PERMIT ISSUANCE DATE	DATE DETERMINATION ENTERED INTO RBLC	DATE DETERMINATION LAST UPDATED	FACILITY_DESCRIPTION	PERMIT_NOTES	PROCESS_NAME	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_2
FL-0335	SUWANNEE MILL	KLAUSER HOLDING USA, INC.	FL	4	2421	321113	01/09/2012	09/05/2012	10/29/2012	5/30/2013	The Suwannee Mill produces dimensional kiln dried lumber and timber byproducts consisting of bark, wood chips, sawdust, and dry shavings. When the facility is fully constructed, the mill has a maximum annual production capacity of 700 MMBF/yr. The mill processes tree-length green saw logs into dimensional lumber. Raw materials, finished lumber and saleable by-products are received and dispatched from the facility by truck or rail. The Suwannee Mill produces dimensional kiln dried lumber and timber byproducts consisting of bark, wood chips, sawdust, and dry shavings. When the facility is fully constructed, the mill has a maximum annual production capacity of 700 MMBF/yr. The mill processes tree-length green saw logs into dimensional lumber. Raw materials, finished lumber and saleable by-products are received and dispatched from the facility by truck or rail.	The Suwannee Mill produces dimensional kiln dried lumber and timber byproducts consisting of bark, wood chips, sawdust, and dry shavings. When the facility is fully constructed, the mill has a maximum annual production capacity of 700 MMBF/yr. The mill processes tree-length green saw logs into dimensional lumber. Raw materials, finished lumber and saleable by-products are received and dispatched from the facility by truck or rail. The mill will operate kilns that heat the green rough sawn lumber to reduce the moisture content to meet required finished product market specifications. The kilns are heated with hot water that is generated in four natural gas-fired boilers (46 million British thermal units per hour (MMBtu/hr)) and two biomass-fired boilers (120 MMBtu/hr). The biomass boilers are fired by untreated bark, wood chips, and sawdust that are byproducts of the mills operation. Clean, untreated woody biomass obtained from off-site sources may also be fired in the biomass boilers	Two(2) Biomass-Fuel Boilers - 120 MMBtu/hr each	wood products	120	MMBTU/H	oven boiler. Biomass is pushed by hydraulic ram onto a step grate system within an initial refractory-lined primary chamber of the boiler, where a three-stage process of drying, pyrolysis, and final combustion begins. In the first step, wet fuel is dried and heated by the combustion gases and radiation from the refractory-lined chamber. Next, the fuel undergoes a pyrolysis process, reducing the wood to hydrocarbon and carbon monoxide (CO) gases. Finally, the exhaust gases are carried into the secondary combustion chamber, where the combustion process is completed with the introduction of secondary combustion air. The heat from the combustion process is recovered to generate the hot water used in the lumber drying kilns. The two biomass boilers will be built and brought on line after the four natural gas boilers. The efficient combustion of woody biomass in the boilers will minimize the formation of particulate matter (PM), nitrogen oxides (NOX), CO and volatile	Nitrogen Oxides (NOx)	SNCR - Selective Non-Catalytic Reduction	0.14	MMBTU/H
SC-0111	FLAKEBOARD AMERICA LIMITED - BENNETTSVILLE MDF	FLAKEBOARD AMERICA LIMITED	SC	4	2493	321219	08/06/2009	12/22/2009	5/9/2012	10/16/2012	THIS FACILITY MANUFACTURES MEDIUM DENSITY FIBERBOARD (MDF) FOR USE PRIMARILY IN THE FURNITURE MANUFACTURING INDUSTRY. THE AVERAGE SIZES OF THE BOARDS PRODUCED ARE 5' X 16' AND 5' X 18' PANELS. FLAKEBOARD PROCESSES SOUTHERN YELLOW PINE CHIPS, PLANER SHAVINGS, SAWDUST AND PLYTRIM, URBAN WOOD, AND INTERNAL/CPB RECLAIM AND SANDERDUST INTO MDF.		SANDERDUST BOILER	RESINATED SANDERDUST	99	MMBTU/H	THE SANDERDUST BOILER IS A SUSPENSION BURNER DESIGN WITH A TOTAL HEAT INPUT RATING OF 99 MMBTU/HR WITH 94 MMBTU/HR GENERATED FROM THE RESINATED SANDERDUST (MAXIMUM) AND 5 MMBTU/HR GENERATED FROM NATURAL GAS (MINIMUM). BOILER IS EQUIPPED WITH A DRY ESP IN SERIES WITH A MULTICLONE, LOW-NOX BURNERS, AND STAGED COMBUSTION.	Nitrogen Oxides (NOx)	LOW-NOX BURNERS AND STAGED COMBUSTION	1.23	LB/MMBTU
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	SC	4	2421	321113	03/28/2012	01/03/2013	8/29/2013	8/27/2014	700 MILLION BOARD FOOT PER YEAR LUMBER MILL		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	4	2421	321113	03/28/2012	01/03/2013	8/29/2013	8/27/2014	700 MILLION BOARD FOOT PER YEAR LUMBER MILL		BIOMASS BOILER EU002	WET BARK, WOOD	120	MMBTU/H		Nitrogen Oxides (NOx)	SNCR	0.14	LB/MMBTU
TN-0159	ERACHEM COMILOG	ERACHEM COMILOG, INC.	TN	4	2819	325199	07/24/2008	01/28/2009	6/4/2009	6/9/2009	MANGANESE PRODUCTS MANUFACTURING		WOOD-FIRED BOILER	WOOD	69.3	MMBTU/H		Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	0.25	LB/MMBTU
*WI-0276	LOUISIANA-PACIFIC CORPORATION	LOUISIANA-PACIFIC CORPORATION	WI	5	2493	321211	02/24/2015	04/02/2015	7/1/2019	7/1/2019	Production of oriented strand board.	Louisiana-Pacific is retiring electrified filter beds (EFB) on two of its Konus thermal oil heaters and re-routing the exhaust through its two dryers and subsequently their respective control devices. Since EFBs were specifically required under the previous PSD BACT, this project triggered a new BACT determination.	B11 & B12 Boilers	Wood Waste	19.4	mmBTU/hr	Boilers B11 and B12 are Konus thermal oil heaters which heat oil for circulation to the Line 1 wafer press and the log conditioning ponds and provide heat for other plant operations. The primary fuel is wood waste which is fed to the burners from a storage bin by a screw auger. Throughput is 19.4 mmBTU/hr each.	Nitrogen Oxides (NOx)	Good Combustion Practices	8.9	LB/HR
*WI-0276	LOUISIANA-PACIFIC CORPORATION	LOUISIANA-PACIFIC CORPORATION	WI	5	2493	321211	02/24/2015	04/02/2015	7/1/2019	7/1/2019	Production of oriented strand board.	Louisiana-Pacific is retiring electrified filter beds (EFB) on two of its Konus thermal oil heaters and re-routing the exhaust through its two dryers and subsequently their respective control devices. Since EFBs were specifically required under the previous PSD BACT, this project triggered a new BACT determination.	B21 & B22 Boilers	Wood Waste	23.8	mmBTU/hr	Boilers B21 and B22 are Konus thermal oil heaters which heat oil for circulation to the Line 2 wafer press and the log conditioning ponds and provide heat for other plant operations. The primary fuel is wood waste which is fed to the burners from a storage bin by a screw auger. Throughput is 23.8 mmBTU/hr each.	Nitrogen Oxides (NOx)	Good Combustion Practices	16.2	LB/HR

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_COUNTY	FACILITY_STATE	SIC_CODE	NAICS_CODE	COMPLETE_APPLICATION_DATE	PERMIT_ISSUANCE_DATE	DATE_DETERMINATION_ENTERED	DATE_DETERMINATION_UPDATED	FACILITY_DESCRIPTION	PERMIT_NOTES	PROCESS_NAME	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
FL-0335	SUWANNEE MILL	KLAUSER HOLDING USA, INC.	SUWANNEE COUNTY	FL	2421	321113	01/09/2012 ACT	09/05/2012 ACT	10/29/2012	5/30/2013	The Suwannee Mill produces dimensional kiln dried lumber and timber byproducts consisting of bark, wood chips, sawdust, and dry shavings. When the facility is fully constructed, the mill has a maximum annual production capacity of 700 MMBF/yr. The mill processes tree-length green saw logs into dimensional lumber. Raw materials, finished lumber and saleable by-products are received and dispatched from the facility by truck or rail.	dimensional kiln dried lumber and timber byproducts consisting of bark, wood chips, sawdust, and dry shavings. When the facility is fully constructed, the mill has a maximum annual production capacity of 700 MMBF/yr. The mill processes tree-length green saw logs into dimensional lumber. Raw materials, finished lumber and saleable by-products are received and dispatched from the facility by truck or rail. The mill will operate kilns that heat the green rough sawn lumber to reduce the moisture content to meet required finished product market specifications. The kilns are heated with hot water that is generated in four natural gas-fired boilers (46 million British thermal units per hour (MMBTu/hr)) and two biomass-fired boilers (120 MMBtu/hr). The biomass boilers are fired by untreated bark, wood chips, and sawdust that are byproducts of the mills operation. Clean, untreated woody biomass obtained from off-	Four(4) Natural Gas Boilers - 46 MMBtu/hour	Natural Gas	46	MMBTU/H	The four natural gas boilers are used to generate the hot water that is used in the lumber kiln drying process. Two boilers each share a common stack for a total of two stacks. In the initial phase of construction, two natural gas fired boilers will supply hot water to one block of kilns. As other kiln blocks are completed, the two other natural gas boilers will be constructed and brought online. Finally, the two biomass boilers will be built and brought on line.	Nitrogen Oxides (NOx)	Low NOx Burner and Flue Gas Recirculation	0.036	LB/MMBTU
FL-0335	SUWANNEE MILL	KLAUSER HOLDING USA, INC.	SUWANNEE COUNTY	FL	2421	321113	01/09/2012 ACT	09/05/2012 ACT	10/29/2012	5/30/2013	The Suwannee Mill produces dimensional kiln dried lumber and timber byproducts consisting of bark, wood chips, sawdust, and dry shavings. When the facility is fully constructed, the mill has a maximum annual production capacity of 700 MMBF/yr. The mill processes tree-length green saw logs into dimensional lumber. Raw materials, finished lumber and saleable by-products are received and dispatched from the facility by truck or rail.	dimensional kiln dried lumber and timber byproducts consisting of bark, wood chips, sawdust, and dry shavings. When the facility is fully constructed, the mill has a maximum annual production capacity of 700 MMBF/yr. The mill processes tree-length green saw logs into dimensional lumber. Raw materials, finished lumber and saleable by-products are received and dispatched from the facility by truck or rail. The mill will operate kilns that heat the green rough sawn lumber to reduce the moisture content to meet required finished product market specifications. The kilns are heated with hot water that is generated in four natural gas-fired boilers (46 million British thermal units per hour (MMBTu/hr)) and two biomass-fired boilers (120 MMBtu/hr). The biomass boilers are fired by untreated bark, wood chips, and sawdust that are byproducts of the mills operation. Clean, untreated woody biomass obtained from off-	Two(2) Biomass-Fuel Boilers - 120 MMBtu/hr each	wood products	120	MMBTU/H	fueled Dutch oven boiler. Biomass is pushed by hydraulic ram onto a step grate system within an initial refractory-lined primary chamber of the boiler, where a three-stage process of drying, pyrolysis, and final combustion begins. In the first step, wet fuel is dried and heated by the combustion gases and radiation from the refractory-lined chamber. Next, the fuel undergoes a pyrolysis process, reducing the wood to hydrocarbon and carbon monoxide (CO) gases. Finally, the exhaust gases are carried into the secondary chamber, where the combustion process is completed with the introduction of secondary combustion air. The heat from the combustion process is recovered to	Nitrogen Oxides (NOx)	SNCR - Seletive Non-Catalytic Reduction	0.14	MMBTU/H
SC-0111	FLAKEBOARD AMERICA LIMITED - BENNETTSVILLE MDF	FLAKEBOARD AMERICA LIMITED	MARLBORO	SC	2493	321219	08/06/2009 ACT	12/22/2009 ACT	5/9/2012	10/16/2012	THIS FACILITY MANUFACTURES MEDIUM DENSITY FIBERBOARD (MDF) FOR USE PRIMARILY IN THE FURNITURE MANUFACTURING INDUSTRY. THE AVERAGE SIZES OF THE BOARDS PRODUCED ARE 5' X 16' AND 5' X 18' PANELS. FLAKEBOARD PROCESSES SOUTHERN YELLOW PINE CHIPS, PLANER SHAVINGS, SAWDUST AND PLYTRIM, URBAN WOOD, AND INTERNAL/CPB RECLAIM AND SANDERDUST INTO MDF.		SANDERDUST BOILER	RESINATED SANDERDUST	99	MMBTU/H	THE SANDERDUST BOILER IS A SUSPENSION BURNER DESIGN WITH A TOTAL HEAT INPUT RATING OF 99 MMBTU/HR WITH 94 MMBTU/HR GENERATED FROM THE RESINATED SANDERDUST (MAXIMUM) AND 5 MMBTU/HR GENERATED FROM NATURAL GAS (MINIMUM). BOILER IS EQUIPPED WITH A DRY ESP IN SERIES WITH A MULTICLONE, LOW-NOX BURNERS, AND STAGED COMBUSTION.	Nitrogen Oxides (NOx)	LOW-NOX BURNERS AND STAGED COMBUSTION	1.23	LB/MMBTU

SC-0111	FLAKEBOARD AMERICA LIMITED - BENNETTSVILLE MDF	FLAKEBOARD AMERICA LIMITED	MARLBOR O	SC	2493	321219	08/06/2009 ACT	12/22/2009 ACT	5/9/2012	10/16/2012	THIS FACILITY MANUFACTURES MEDIUM DENSITY FIBERBOARD (MDF) FOR USE PRIMARILY IN THE FURNITURE MANUFACTURING INDUSTRY. THE AVERAGE SIZES OF THE BOARDS PRODUCED ARE 5' X 16' AND 5' X 18' PANELS. FLAKEBOARD PROCESSES SOUTHERN YELLOW PINE CHIPS, PLANER SHAVINGS, SAWDUST AND PLYTRIM, URBAN WOOD, AND INTERNAL/CPB RECLAIM AND SANDERDUST INTO MDF.	FACE PRIMARY DRYER	NATURAL GAS	45	MMBTU/H	NATURAL GAS FIRED, LOW-NOX BURNER USED IN THE PRIMARY FACE DRYER OF AN MDF MANUFACTURING PROCESS	Nitrogen Oxides (NOx)	LOW-NOX BURNERS	0	
SC-0111	FLAKEBOARD AMERICA LIMITED - BENNETTSVILLE MDF	FLAKEBOARD AMERICA LIMITED	MARLBOR O	SC	2493	321219	08/06/2009 ACT	12/22/2009 ACT	5/9/2012	10/16/2012	THIS FACILITY MANUFACTURES MEDIUM DENSITY FIBERBOARD (MDF) FOR USE PRIMARILY IN THE FURNITURE MANUFACTURING INDUSTRY. THE AVERAGE SIZES OF THE BOARDS PRODUCED ARE 5' X 16' AND 5' X 18' PANELS. FLAKEBOARD PROCESSES SOUTHERN YELLOW PINE CHIPS, PLANER SHAVINGS, SAWDUST AND PLYTRIM, URBAN WOOD, AND INTERNAL/CPB RECLAIM AND SANDERDUST INTO MDF.	CORE PRIMARY DRYER	NATURAL GAS	45	MMBTU/H	NATURAL GAS FIRED, LOW-NOX BURNER USED IN THE PRIMARY CORE DRYER OF AN MDF MANUFACTURING PROCESS	Nitrogen Oxides (NOx)	LOW-NOX BURNERS	0	
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	ORANGEB URG	SC	2421	321113	03/28/2012 ACT	01/03/2013 ACT	8/29/2013	8/27/2014	700 MILLION BOARD FOOT PER YEAR LUMBER MILL	BIOMASS BOILER EU001	WET BARK, WOOD	120	MMBTU/H		Nitrogen Oxides (NOx)	SNCR	0.14	LB/MMBT U
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	ORANGEB URG	SC	2421	321113	03/28/2012 ACT	01/03/2013 ACT	8/29/2013	8/27/2014	700 MILLION BOARD FOOT PER YEAR LUMBER MILL	BIOMASS BOILER EU002	WET BARK, WOOD	120	MMBTU/H		Nitrogen Oxides (NOx)	SNCR	0.14	LB/MMBT U
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	ORANGEB URG	SC	2421	321113	03/28/2012 ACT	01/03/2013 ACT	8/29/2013	8/27/2014	700 MILLION BOARD FOOT PER YEAR LUMBER MILL	NATURAL GAS BOILER EU003	NATURAL GAS	46	MMBTU/H		Nitrogen Oxides (NOx)		0.036	LB/MMBT U
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	ORANGEB URG	SC	2421	321113	03/28/2012 ACT	01/03/2013 ACT	8/29/2013	8/27/2014	700 MILLION BOARD FOOT PER YEAR LUMBER MILL	NATURAL GAS BOILER EU004	NATURAL GAS	46	MMBTU/H		Nitrogen Oxides (NOx)		0.036	LB/MMBT U
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	ORANGEB URG	SC	2421	321113	03/28/2012 ACT	01/03/2013 ACT	8/29/2013	8/27/2014	700 MILLION BOARD FOOT PER YEAR LUMBER MILL	NATURAL GAS BOILER EU005	NATURAL GAS	46	MMBTU/H		Nitrogen Oxides (NOx)		0.036	LB/MMBT U
SC-0149	KLAUSNER HOLDING USA, INC	KLAUSNER HOLDING USA, INC	ORANGEB URG	SC	2421	321113	03/28/2012 ACT	01/03/2013 ACT	8/29/2013	8/27/2014	700 MILLION BOARD FOOT PER YEAR LUMBER MILL	NATURAL GAS BOILER EU006	NATURAL GAS	46	MMBTU/H		Nitrogen Oxides (NOx)		0.036	LB/MMBT U
TN-0159	ERACHEM COMILOG	ERACHEM COMILOG, INC.	HUMPHREYS	TN	2819	325199	07/24/2008 ACT	01/28/2009 ACT	6/4/2009	6/9/2009	MANGANESE PRODUCTS MANUFACTURING	WOOD-FIRED BOILER	WOOD	69.3	MMBTU/H		Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	0.25	LB/MMBT U

*WI-0276	LOUISIANA-PACIFIC CORPORATION	LOUISIANA-PACIFIC CORPORATION	SAWYER	WI	2493	321211	02/24/2015 ACT	04/02/2015 ACT	7/1/2019	7/1/2019	Production of oriented strand board.	Louisiana-Pacific is retiring electrified filter beds (EFB) on two of its Konus thermal oil heaters and re-routing the exhaust through its two dryers and subsequently their respective control devices. Since EFBs were specifically required under the previous PSD BACT, this project triggered a new BACT determination.	B11 & B12 Boilers	Wood Waste	19.4	mmBTU/hr	Boilers B11 and B12 are Konus thermal oil heaters which heat oil for circulation to the Line 1 wafer press and the log conditioning ponds and provide heat for other plant operations. The primary fuel is wood waste which is fed to the burners from a storage bin by a screw auger. Throughput is 19.4 mmBTU/hr each.	Nitrogen Oxides (NOx)	Good Combustion Practices	8.9	LB/HR
*WI-0276	LOUISIANA-PACIFIC CORPORATION	LOUISIANA-PACIFIC CORPORATION	SAWYER	WI	2493	321211	02/24/2015 ACT	04/02/2015 ACT	7/1/2019	7/1/2019	Production of oriented strand board.	Louisiana-Pacific is retiring electrified filter beds (EFB) on two of its Konus thermal oil heaters and re-routing the exhaust through its two dryers and subsequently their respective control devices. Since EFBs were specifically required under the previous PSD BACT, this project triggered a new BACT determination.	B21 & B22 Boilers	Wood Waste	23.8	mmBTU/hr	Boilers B21 and B22 are Konus thermal oil heaters which heat oil for circulation to the Line 2 wafer press and the log conditioning ponds and provide heat for other plant operations. The primary fuel is wood waste which is fed to the burners from a storage bin by a screw auger. Throughput is 23.8 mmBTU/hr each.	Nitrogen Oxides (NOx)	Good Combustion Practices	16.2	LB/HR

APPENDIX C: SCR COST ESTIMATE FOR BOILERS AND DRYERS

Table C-1. Cost Analysis Supporting Information for Tail-end SCR

Parameter	Columbia Falls Boiler			Units	Note(s)
	90% Control	80% Control	70% Control		
Boiler Firing Rate	292	292	292	MMBtu/hr	1
Potential NO _x Emission Factor	0.458	0.458	0.458	lb/MMBtu	1
Potential NO _x Emissions	587	587	587	tpy	1
Removal Efficiency	90	80	70	%	2
Pollutant Removed @ % control	528	470	411	tpy	3
NO _x Removal Factor (NRF)	1.13	1.00	0.88		14
SCR Inlet Airflow (before reheating)	151,000	151,000	151,000	acfm	4
SCR Inlet Temperature (before reheating)	500	500	500	° F	4
SCR Inlet Temperature (after reheating)	700	625	575	° F	4
SCR Inlet Flow Rate	393,500	393,500	393,500	lb/hr	6
Additional heat required	49.95467235	31.2	18.7	Btu/lb	7
	20	12	7	MMBtu/hr	
	172,197	107,622.97	64,573.78	MMBtu/yr	8
Natural Gas Cost	5.53	5.53	5.53	\$/MMBtu	4
Fuel Sulfur Content	0.01	0.01	0.01	%	5
Ammonia Slip Allowed	5	5	5	ppm	6
Volume of Catalyst	1,240	1,240	1,240	ft ³	6
Mass Flow Rate of Reagent	46.87	41.66	36.45	lb/hr	6
Concentration of Stored Reagent Solution	19	19	19	% Reagent	6
Pressure Drop Across the SCR and Ductwork	7.5	7.5	7.5	inches of H ₂ O	6
Electricity Usage	162	162	162	kW	9
Number of Hours of Operator Labor	4	4	4	hrs/day	15
Labor Rate (Including Benefits)	60	60	60	\$/hr	15
Catalyst Cost, Initial	252.73	252.73	252.73	\$/ft ³	10
Catalyst Cost, Replacement	252.73	252.73	252.73	\$/ft ³	10
19% Ammonia Solution Cost	0.04	0.04	0.04	\$/lb	10
Electricity Cost	0.046	0.046	0.046	\$/kW-hr	11
SCR Equipment Life	20	20	20	years	12
Interest Rate	5.25%	5.25%	5.25%	%	12
2016 \$	541.7	541.7	541.7	n/a	13
2018 \$	603.1	603.1	603.1	n/a	13

1. Heat input based on specified maximum tons of fuel burned and HHV of fuel. Inlet emissions based on uncontrolled emissions in flue gas data provided by Mitchell Leu in January 2011.
2. Based on call with EPA Region 8 and Anna Henolson (Trinity) on November 30, 2011, EPA requested that SCR cost calculations be presented for three different case scenarios: for control efficiencies at 70, 80 and 90%.
3. Pollutant Removed (tpy) = (Removal Efficiency, %) × (Potential Emissions, tpy).
4. Reheated boiler exhaust temperatures based on EPA Cost Manual, Section 4.2, Figure 2.2. Inlet temperature before reheating based on maximum boiler outlet temperature data provided by Mitchell Leu in January 2011. Cost of natural gas from most recent U.S. Energy Information Administration data for Montana.
5. Sulfur content based on fuel composition sample analysis from December 2008.
6. SCR design specifications based on vendor quote from Fuel Tech, Inc. to Anna Henolson (Trinity) on 12/19/2011. Pressure drop across the SCR system was provided in vendor quote as 5 inches in WC. It is assumed that the pressure drop across the ductwork is an additional 2.5 in WC. The mass flowrate of reagent for different control efficiencies was scaled based on the mass of pollutant removed.
7. An average heat capacity of 0.249773361735809 Btu/lb-F is used to calculate the heat needed to raise the temperature of flue gas.
8. The boiler's maximum outlet temperature is 500 F. The boiler operates for 8760 hours / yr.
9. Electricity usage requirement based on equation 2.61 of EPA Cost Control Manual, Section 4.2
10. Catalyst costs based on example problem in EPA Cost Manual, Section 4.2, 2.5 Example problem #1. Costs converted from 2016 \$ to 2018 \$.
11. Cost based on most recent (June 2019) average MT electricity cost, per EIA (https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a).
12. Assumed an average rate of interest of 5.25% based on bank prime rate on 8/21/19 (<https://www.federalreserve.gov/releases/h15/>)
13. Values based on Chemical Engineering's Plant Cost Index (CEPCI)
14. Per explanation of variables in EPA Cost Manual, Section 4.2, Equation 2.48
15. Per example problem number two in EPA Cost manual, Section 4.2

Table C-2. Cost Analysis for SCR

Capital Cost	Columbia Falls Boiler			EPA Cost Manual SCR Section Equation ²	Notation
	90% Control	80% Control	70% Control		
Total Capital Investment⁷	6,292,791	6,292,791	6,292,791	2.53	$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV \times RF$
Operating Cost	Columbia Falls Boiler				Notation
<i>Direct Annual Costs</i>					
Operating and Supervisory Labor	87,600	87,600	87,600		OSL
Annual Maintenance Cost	31,464	31,464	31,464	2.57	AMC
Annual Reagent Cost	34,460	30,631	26,802	2.58	ARC
Annual Electricity Cost	24,003	24,003	24,003	2.61	AEC
Annual Catalyst Cost ¹	99,128	99,128	99,128	2.64, 2.65, 2.66	ACC
Annual Air Reheat Natural Gas Cost	951,527	594,704	356,823		ANGC
Total Direct Annual Costs	1,228,182	867,531	625,820	2.56 (modified)³	$DAC = OSL + AMC + ARC + AEL + ACC + ANGC$
<i>Indirect Annual Costs</i>					
Administrative Charges	2,666	2,666	2,666	2.69	AC
Capital Recovery	515,709	515,709	515,709	2.7, 2.71	CR
Total Indirect Annual Costs	518,374	518,374	518,374	2.68	$IDAC = AC + CR$
Total Annual Cost	1,746,556	1,385,905	1,144,194	2.72	$TAC = DAC + IDAC$
Pollutant Removed (tpy) @ % control	528	470	411		tpy
Cost per ton of NO_x Removed @ % control	3,306	2,952	2,785	2.73	$\\$/ton = TAC / Pollutant Removed$

1. Catalyst replacement cost assumes 24,000 hours of operational life and 8760 hours per year of SCR operation.
2. U.S. EPA, EPA Air Pollution Control Cost Manual (7th Edition), April 2019, Section 4, Chapter 1. Equations noted for each cost in the eq. ref. column.
3. Modified equation 2.56 to account for labor costs and the cost to reheat the flue gas for a tail-end SCR application.

Table C-3. Cost Analysis Supporting Information for SCR

Parameter	Evergreen Boiler			Units	Note(s)
	90% Control	80% Control	70% Control		
Maximum Boiler Capacity	196	196	196	MMBtu/hr	1
Potential NO _x Emission Factor	0.189	0.189	0.189	lb/MMBtu	1
Potential NO _x Emissions	162	162	162	tpy	1
Removal Efficiency	90	80	70	%	2
Pollutant Removed @ % control	146	130	113	tpy	3
NO _x Removal Factor (NRF)	1.13	1.00	0.88		14
SCR Inlet Airflow (before reheating)	55,500	55,500	55,500	acfm	4
SCR Inlet Temperature (before reheating)	430	430	430	° F	4
SCR Inlet Temperature (after reheating)	700	625	575	° F	4
SCR Inlet Flow Rate	240,300	240,300	240,300	lb/hr	6
Additional heat required	67.43880767	48.70580554	36.21713745	Btu/lb	7
	16	12	9	MMBtu/hr	
	141,961	102,527	76,238	MMBtu/yr	8
Natural Gas Cost	5.53	5.53	5.53	\$/MMBtu	4
Fuel Sulfur Content	0.01	0.01	0.01	%	5
Ammonia Slip Allowed	5	5	5	ppm	6
Volume of Catalyst	607	607	607	ft ³	6
Mass Flow Rate of Reagent	12.94	11.50	10.07	lb/hr	6
Concentration of Stored Reagent Solution	19	19	19	% Reagent	6
Pressure Drop Across the SCR and Ductwork	6.0	6.0	6.0	inches of H ₂ O	6
Electricity Usage	108.5	108.5	108.5	kW	9
Number of Hours of Operator Labor	4	4	4	hrs/day	15
Labor Rate (Including Benefits)	60	60	60	\$/hr	15
Catalyst Cost, Initial	252.73	252.73	252.73	\$/ft ³	10
Catalyst Cost, Replacement	252.73	252.73	252.73	\$/ft ³	10
19% Ammonia Solution Cost	0.04	0.04	0.04	\$/lb	10
Electricity Cost	0.05	0.05	0.05	\$/kW-hr	11
SCR Equipment Life	20	20	20	years	12
Interest Rate	5.25%	5.25%	5.25%	%	12
2016 \$	541.7	541.7	541.7	n/a	13
2018 \$	603.1	603.1	603.1	n/a	13

- Heat input based on specified maximum tons of fuel burned and HHV of fuel. Inlet emissions based on uncontrolled emissions in flue gas data provided by Mitchell Leu in January 2011.
- Based on call with EPA Region 8 and Anna Henolson (Trinity) on November 30, 2011, EPA requested that SCR cost calculations be presented for three different case scenarios: for control efficiencies at 70, 80 and 90%.
- Pollutant Removed (tpy) = (Removal Efficiency, %) × (Potential Emissions, tpy).
- Reheated boiler exhaust temperatures based on EPA Cost Manual, Section 4.2, Figure 2.2. Inlet temperature before reheating based on maximum boiler outlet temperature data provided by Mitchell Leu in January 2011. Cost of natural gas from most recent U.S. Energy Information Administration data for Montana.
- Sulfur content based on fuel composition sample analysis from December 2008.
- SCR design specifications based on vendor quote from Fuel Tech, Inc. to Anna Henolson (Trinity) on 12/19/2011. Pressure drop across the SCR system was provided in vendor quote as 5 inches in WC. It is assumed that the pressure drop across the ductwork is an additional 2.5 in WC. The mass flowrate of reagent is calculated using EPA Cost Manual, Section 4.2, Equation 2.35.
- An average heat capacity of 0.249773361735809 Btu/lb-F is used to calculate the heat needed to raise the temperature of flue gas.
- The boiler's maximum outlet temperature is 500 F. The boiler operates for 8760 hours / yr.
- Electricity usage requirement based on equation 2.61 of EPA Cost Control Manual, Section 4.2
- Catalyst costs based on example problem in EPA Cost Manual, Section 4.2, 2.5 Example problem #1. Costs converted from 2016 \$ to 2018 \$.
- Cost based on most recent (June 2019) average MT electricity cost, per EIA (https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a).
- Assumed an average rate of interest of 5.25% based on bank prime rate on 8/21/19 (<https://www.federalreserve.gov/releases/h15/>)
- Values based on Chemical Engineering's Plant Cost Index (CEPCI)
- Per explanation of variables in EPA Cost Manual, Section 4.2, Equation 2.48
- Per example problem number two in EPA Cost manual, Section 4.2

Table C-4. Cost Analysis for SCR

Capital Cost	Evergreen Boiler			EPA Cost Manual SCR Section Equation ²	Notation
	90% Control	80% Control	70% Control		
Total Capital Investment⁷	4,825,309	4,825,309	4,825,309	2.53	$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV \times RF$

Operating Cost	Evergreen Boiler				Notation
<i>Direct Annual Costs</i>					
Operating and Supervisory Labor	87,600	87,600	87,600		OSL
Annual Maintenance Cost	24,127	24,127	24,127	2.57	AMC
Annual Reagent Cost	8,214	7,302	6,389	2.58	ARC
Annual Electricity Cost	13,890	13,890	13,890	2.61	AEC
Annual Catalyst Cost ¹	48,576	48,576	48,576	2.64, 2.65, 2.66	ACC
Annual Air Reheat Natural Gas Cost	784,448	566,545	421,277		ANGC
<i>Total Direct Annual Costs</i>	<i>966,854</i>	<i>748,040</i>	<i>601,859</i>	<i>2.56 (modified)³</i>	<i>$DAC = OSL + AMC + ARC + AEL + ACC + ANGC$</i>
<i>Indirect Annual Costs</i>					
Administrative Charges	2,657	2,657	2,657	2.69	AC
Capital Recovery	395,445	395,445	395,445	2.7, 2.71	CR
<i>Total Indirect Annual Costs</i>	<i>398,102</i>	<i>398,102</i>	<i>398,102</i>	<i>2.68</i>	<i>$IDAC = AC + CR$</i>
Total Annual Cost	1,364,956	1,146,142	999,961	2.72	$TAC = DAC + IDAC$
Pollutant Removed (tpy) @ % control	146	130	113		tpy
Cost per ton of NO_x Removed @ % control	9,358	8,840	8,815	2.73	$\\$/ton = TAC / Pollutant\ Removed$

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

2. U.S. EPA, EPA Air Pollution Control Cost Manual (7th Edition), April 2019, Section 4, Chapter 1. Equations noted for each cost in the eq. ref. column.

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

Table C-5. Cost Estimation to Reheat Flue Gas Post Bio-Filter in Dryers

Parameters	Line 1 Dryer	Line 2 Dryer	Unit
Maximum Dryer Capacity	100	85	MMBtu/hr
Potential NOx Emission Factor	0.75	0.54	lb/MMBtu
Potential Emissions	329	200	tpy
Maximum Removal Efficiency	90	90	%
Pollutant Removed	296	180	tpy
SCR Inlet Airflow (before reheating)	900,000	600,000	acfm
SCR Inlet Temperature (before reheating)	104	104	° F
SCR Inlet Airflow (after reheating)	1,851,064	1,234,043	acfm
SCR Inlet Temperature (after reheating)	700	700	° F
Mass Flow Rate	3,801,337	2,534,225	lb/hr
Additional heat required	151.98	151.98	Btu/lb
	577.73	385.15	MMBtu/hr
	5,060,891	3,373,927	MMBtu/yr
Natural gas cost	5.53	5.53	\$/MMBtu
Total Reheating Cost	27,965,534	18,643,689	\$
Reheat Cost per ton NOx removed	94,590	103,717	\$/ton

Footnotes:

Molecular weight of dry air	28.95 lb/lbmol
Volume of 1 lbmol air @ 68F	385 ft ³ /lbmol
Average heat capacity of air	0.255 Btu/lb*F

Table C-6. Cost Estimation to Reheat Flue Gas Pre Bio-Filter in Dryers

Parameters	Line 1 Dryer	Line 2 Dryer	Unit
Maximum Dryer Capacity	100	85	MMBtu/hr
Potential NOx Emission Factor	0.75	0.54	lb/MMBtu
Potential Emissions	329	200	tpy
Maximum Removal Efficiency	90	90	%
Pollutant Removed	296	180	tpy
SCR Inlet Airflow (before reheating)	268,000	198,000	acfm
SCR Inlet Temperature (before reheating)	140	130	° F
SCR Inlet Airflow (after reheating)	518,133	389,288	acfm
SCR Inlet Temperature (after reheating)	700	700	° F
Mass Flow Rate (before reheating)	1,064,037	799,441	lb/hr
Additional heat required	142.8	145.35	Btu/lb
	151.94	116.20	MMBtu/hr
	1,331,033	1,017,901	MMBtu/yr
Natural gas cost	5.53	5.53	\$/MMBtu
Total Reheating Cost	7,355,040	5,624,727	\$
Reheat Cost per ton NOx removed	24,878	31,291	\$/ton

Footnotes:

Molecular weight of dry air	28.95 lb/lbmol
Volume of 1 lbmol air @ 68F	385 ft ³ /lbmol
Average heat capacity of air	0.255 Btu/lb*F

Table C-7. Cost Estimate to Install New Firebox in Line 1 Dryers

Parameters	Line 1 Dryer	Unit
Dryer Fuel Usage ^a	100	MMBtu/hr
Potential NOx Emission Factor	0.75	lb/hr
Potential Emissions	329	tpy
Maximum Removal Efficiency ^b	23.0	%
Pollutant Removed	76	tpy
Capital Cost of Burner ^c	4,379,811	\$
Equipment Life	20	years
Interest Rate	5.25	%
Capital Recovery Factor	0.082	
Annualized Burner Cost	358,936	\$
Cost per ton NOx removed	4,751	\$/ton

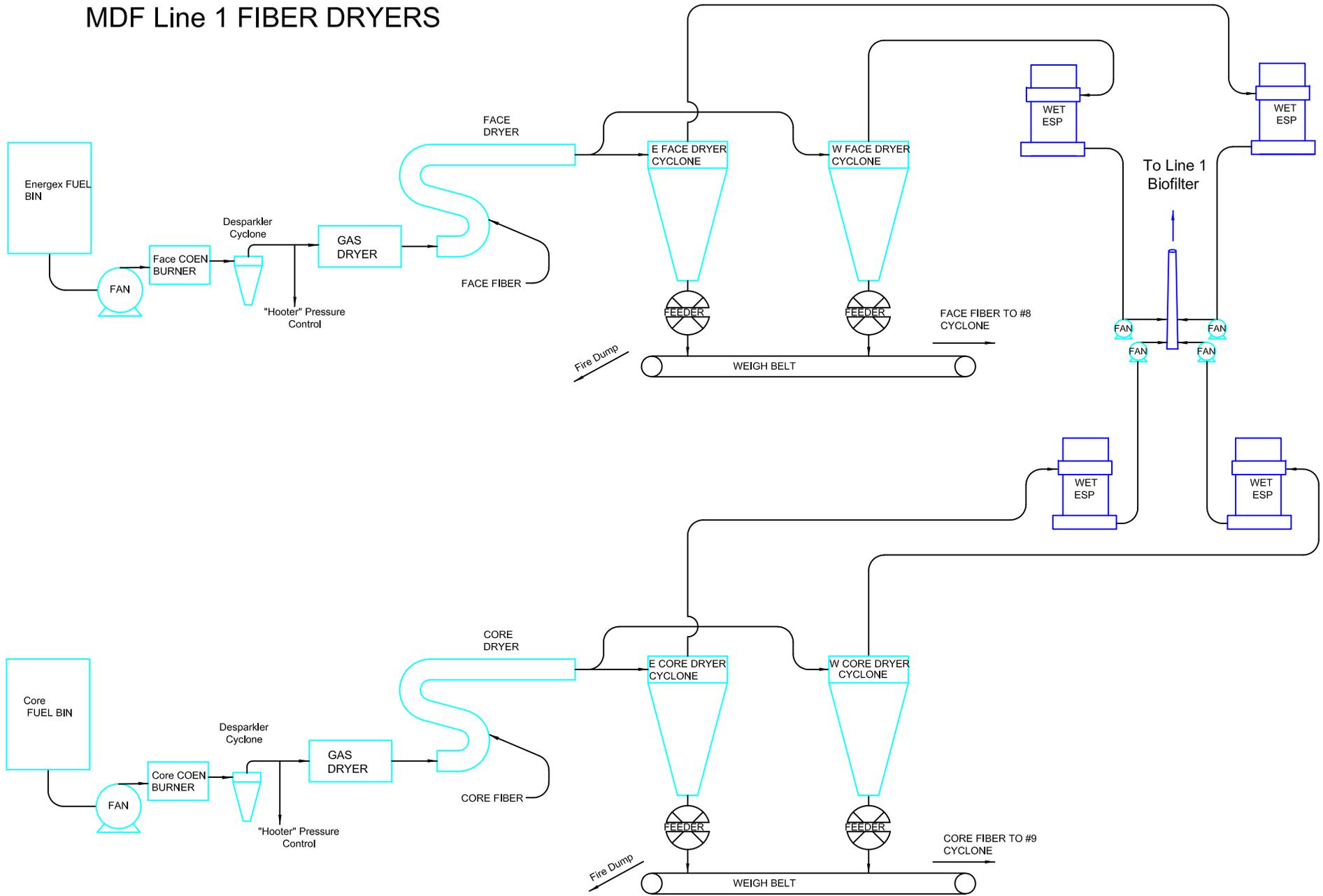
^a Maximum dryer capacity

^b Removal efficiency based on Line 2 Dryers design control efficiency

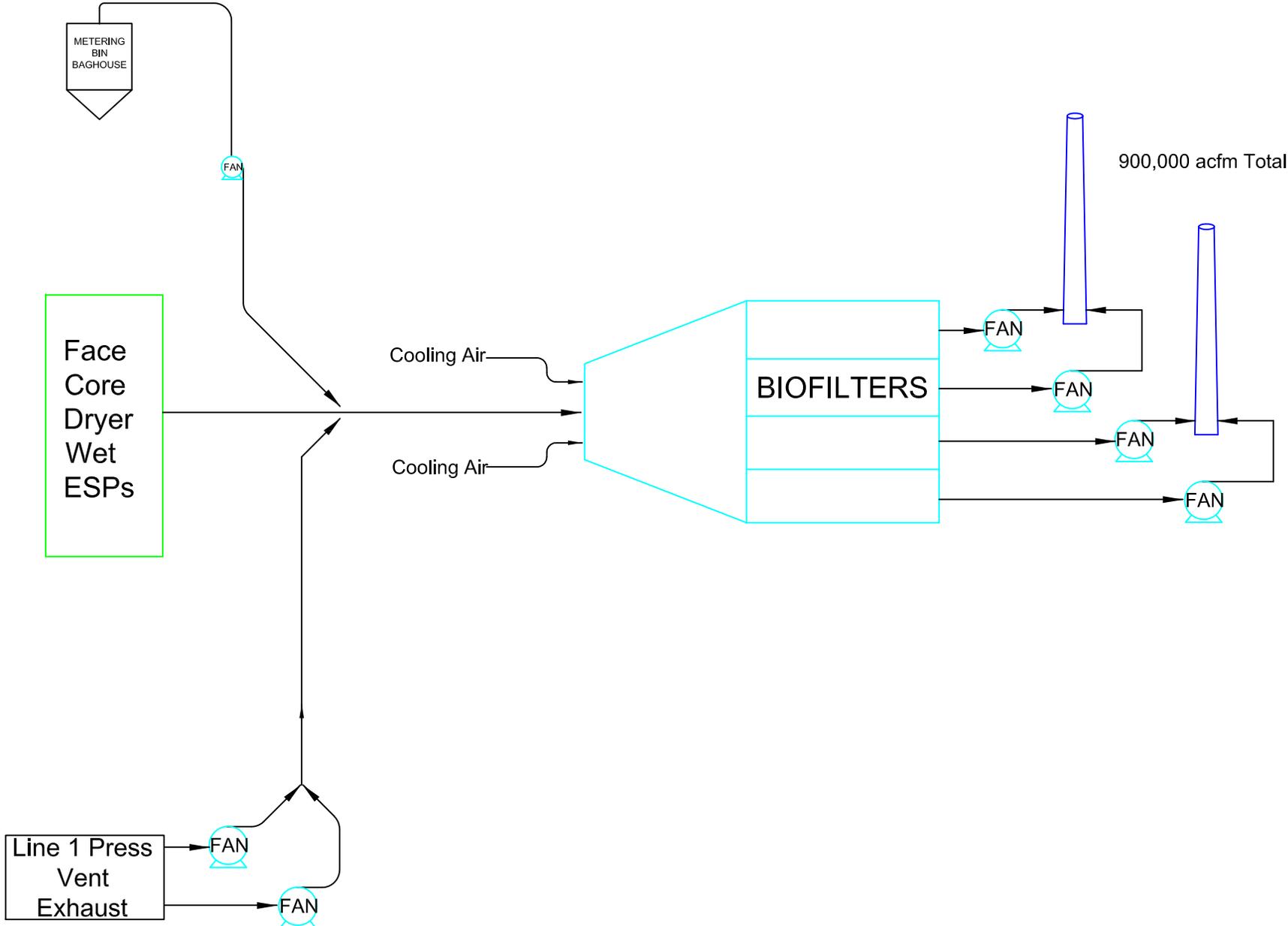
^c Capital cost of burner was estimated by Weyerhaeuser during Regional Haze Rule Round 1 based on Line 2 capital projects and bids. Is scaled up from 2010 estimated value using the Chemical Engineering's Plant Cost Index (CEPCI).

APPENDIX D: PROCESS FLOW DIAGRAM FOR LINE 1 AND LINE 2 DRYERS

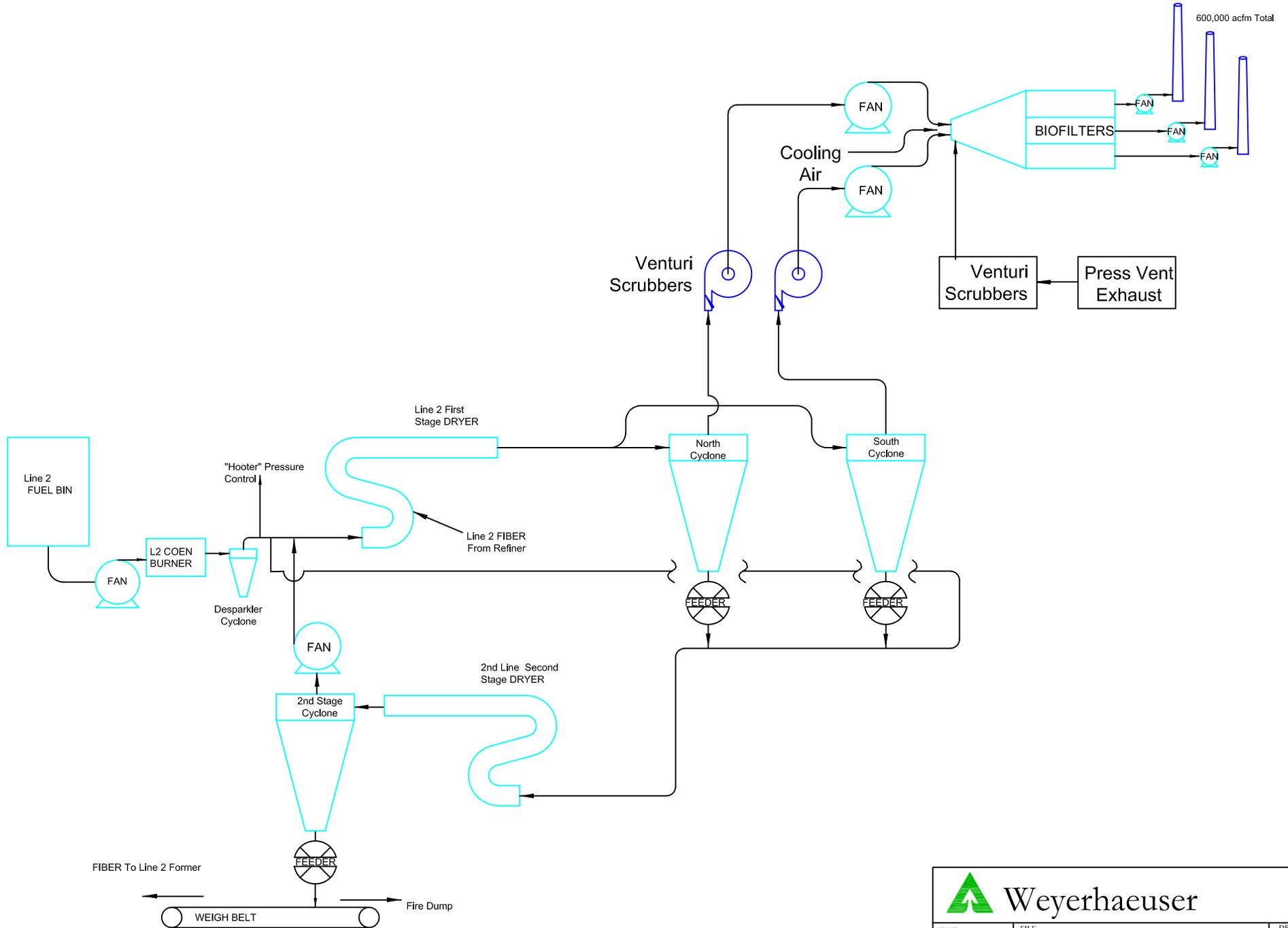
MDF Line 1 FIBER DRYERS



MDF Line 1 Biofilter



MDF Line 2 Fiber Dryers



 Weyerhaeuser		DRAWN BY Mitchell Leu
SCALE:	FILE	MDF-FLOW for DHA.dwg
DATE: 6/17/16		
MDF FLOW CHART - Line 2 Drying		