# REGIONAL HAZE FOUR-FACTOR ANALYSIS

## WOODGRAIN MILLWORK, INC.

*Prepared for*

**WOODGRAIN MILLWORK, INC.**

LA GRANDE, OREGON

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*Project No. 1863.02.01*

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# ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| $/ton | dollars per ton of pollutant controlled |
| °F | degrees Fahrenheit |
| Analysis | Regional Haze Four Factor Analysis |
| BH | baghouse |
| CAA | Clean Air Act |
| Control Cost Manual | USEPA Air Pollution Control Cost Manual |
| DEQ | Oregon Department of Environmental Quality |
| ESP | electrostatic precipitator |
| facility | particleboard manufacturing facility located at 62621 Oregon Highway 82, La Grande, Oregon 97850 |
| Federal Guidance Document | Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003 |
| GFD | green furnish dryer |
| MFA | Maul Foster and Alongi, Inc. |
| MMBtu/hr | million British thermal units per hour |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NO | nitric oxide |
| $NO_X$ | oxides of nitrogen |
| PM | particulate matter |
| $PM_{10}$ | particulate matter with an aerodynamic diameter of 10 microns or less |
| SCR | selective catalytic reduction |
| SIP | State Implementation Plan |
| SNCR | selective non-catalytic reduction |
| $SO_2$ | sulfur dioxide |
| USEPA | U.S. Environmental Protection Agency |
| Woodgrain | Woodgrain Millwork, Inc. |

# 1 INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) is developing a State Implementation Plan (SIP) as part of the Regional Haze program in order to protect visibility in Class I areas. The SIP developed by the DEQ covers the second implementation period ending in 2028, and must be submitted to the U.S. Environmental Protection Agency (USEPA) for approval. The second implementation period focuses on making reasonable progress toward national visibility goals, and assesses progress made since the 2000 through 2004 baseline period.

In a letter dated December 23, 2019, the DEQ requested that 31 industrial facilities conduct a Regional Haze Four Factor Analysis (Analysis). The Analysis estimates the cost associated with reducing visibility-impairing pollutants including, particulate matter with an aerodynamic diameter of 10 microns or less ($PM_{10}$), oxides of nitrogen ($NO_X$), and sulfur dioxide ($SO_2$). The four factors that must be considered when assessing the states' reasonable progress, which are codified in Section 169A(g)(1) of the Clean Air Act (CAA), are:

(1) The cost of control,

(2) The time required to achieve control,

(3) The energy and non-air-quality environmental impacts of control, and

(4) The remaining useful life of the existing source of emissions.

The DEQ has provided the following three guidance documents for facilities to reference when developing their Analysis:

(1) USEPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003 (Federal Guidance Document).

(2) USEPA Air Pollution Control Cost Manual, which is maintained online and includes separate chapters for different control devices as well as several electronic calculation spreadsheets that can be used to estimate the cost of control for several control devices (Control Cost Manual).

(3) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, [particulate matter with an aerodynamic diameter of 2.5 microns or less] $PM_{2.5}$, and Regional Haze (November 2018), EPA-454/R-18-009.

The development of this Analysis has relied on these guidance documents.

## 1.1 Facility Description

Woodgrain Millwork, Inc. (Woodgrain) owns and operates a particleboard manufacturing facility located at 62621 Oregon Highway 82, La Grande, Oregon 97850 (the facility). The facility currently operates under Title V Operating Permit No. 31-0002-TV-01, issued by the DEQ to Boise Cascade

Wood Products, LLC, on July 30, 2014. Per Addendum No. 1 to the existing permit, facility ownership was revised from Boise Cascade Wood Products, LLC, to Woodgrain on January 11, 2019. The facility is a major stationary source of criteria and hazardous air pollutants.

The facility is located northwest of La Grande city center, just outside the extents of Island City proper. The area immediately surrounding the facility is predominantly characterized by flat terrain and agricultural land use. The nearest Class I area is the Eagle Cap Wilderness Area, approximately 25 kilometers east-southeast of the facility.

## 1.2 Process Description

Both green or pre-dried wood furnish is delivered by trucks and used as raw materials. The wood furnish is unloaded and pneumatically conveyed to one of three storage buildings. Green wood furnish at approximately 50 percent moisture content is dried prior to processing. Once dry, wood furnish is sent to either of the two particleboard manufacturing lines and separated into face and/or core material.

The face and core materials are then screened, refined, dried, mixed with urea-formaldehyde resins, and formed into mats. Various additives are introduced to the mat in order to meet product specifications. The mats are loaded into one of two multiplaten presses and, under heat and pressure, cured into particleboard panels. The cured panels are then cooled and stabilized prior to sanding, sizing, and final packaging. The facility produces industrial grade particleboard in thicknesses ranging from five-sixteenths to one and three-sixteenths inches.

Two boilers are used to produce steam to heat the finish dryers and presses. Sanderdust generated by the sanding operation is collected and used as fuel in the Line 2 boiler and green furnish dryer (GFD). The Line 1 boiler is fueled by natural gas-fired combustion with propane back-up. Trim from the panel sizing operation, reject material, and other wood materials are returned to the process as raw material.

# 2 APPLICABLE EMISSION SOURCES

Woodgrain retained Maul Foster & Alongi, Inc. (MFA) to assist the facility with completing this Analysis. Emissions rates for each visibility-impairing pollutant ($PM_{10}$, $NO_X$, and $SO_2$) were tabulated. These emissions rates represent a reasonable projection of actual source operation in the year 2028. As stated in the Federal Guidance Document,[1] estimates of 2028 emission rates should be used for the Analysis. It is assumed that current potential to emit (Plant Site Emission Limit) emission rates at the facility represent the most reasonable estimate of actual emissions in 2028.

After emission rates were tabulated for each emissions unit, estimated emission rates for each pollutant were sorted from the highest emission rate to the lowest. The emission units collectively contributing

[1] See Federal Guidance Document page 17, under the heading "Use of actual emissions versus allowable emissions."

to 90 percent of the total facility emissions rate for a single pollutant were identified and selected for the Analysis.

This method of emission unit selection ensures that larger emission units are included in the Analysis. Larger emission units represent the likeliest potential for reduction in emissions that would contribute to a meaningful improvement in visibility at federal Class I areas. It would not be reasonable to assess many small emission units—neither on an individual basis (large reductions for a small source likely would not improve visibility and would not be cost effective), nor on a collective basis (the aggregate emission rate would be no greater than 10 percent of the overall facility emissions rate, and thus not as likely to improve visibility at federal Class I areas, based solely on the relatively small potential overall emission decreases from the facility).

The following sections present the source selection, associated emission rates that will be used in the Analysis, and pertinent source configuration and exhaust parameters.

## 2.1 Sources of $PM_{10}$ Emissions

A summary of the selected emission units and associated $PM_{10}$ emission rates included in the Analysis is presented in Table 2-1 (attached). A detailed description of each emissions unit is presented below. The permit emission unit ID is shown in parentheses.

### 2.1.1 Line 1 and 2 Boilers (B1 and B2)

The Line 1 boiler is a Babcock and Wilcox natural gas-fired package boiler, with propane backup. The Line 1 boiler has a maximum rated heat input capacity of 56 million British thermal units per hour (MMBtu/hr). Exhaust from the Line 1 boiler is used to supplement heating in the Line 1 core dryer or is vented directly to the atmosphere.

The Line 2 boiler is also a Babcock and Wilcox industrial watertube type "D" boiler, fueled primarily by sanderdust with concurrent natural gas usage and propane as backup. The sanderdust is pneumatically conveyed directly into the boiler combustion chamber as fuel. Its maximum rated heat input capacity is 80 MMBtu/hr. Exhaust from the Line 2 boiler is routed to a dry electrostatic precipitator (ESP) for control of fine particulate emissions prior to emitting to the atmosphere

The Line 1 and 2 boilers are subject to, and required to comply with, the National Emission Standard for Hazardous Air Pollutants (NESHAP) for Major Source Industrial, Commercial, and Institutional Boilers and Process Heaters, codified at Title 40 Code of Federal Regulations Part 63 Subpart DDDDD, as introduced under section 112(g) of the CAA, effective November 20, 2015. Based on USEPA guidance[2] provided to states for the Second Implementation Period, the USEPA believes it is reasonable for states to exclude an emissions unit for further analysis if:

> For the purpose of [particulate matter (PM)] control measures, a unit that is subject to and complying with any CAA section 112 [NESHAP] or CAA section 129 solid waste combustion rule, promulgated

[2] USEPA Office of Air Quality Planning and Standards, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period." August 2019.

> or reviewed since July 31, 2013, that uses total or filterable PM as a surrogate for metals or has specific emission limits for metals. The NESHAPs are reviewed every 8 years and their emission limits for PM and metals reflects at least the maximum achievable control technology for major sources and the generally available control technology for area sources. It is unlikely that an analysis of control measures for a source meeting one of these NESHAPs would conclude that even more stringent control of PM is necessary to make reasonable progress.

Based on the USEPA guidance, both boilers were excluded from further evaluation in the $PM_{10}$ Analysis.

### 2.1.2 Green Furnish Dryer (GFD/C46)

The GFD is utilized to dry green wood furnish delivered to the facility prior to processing. The GFD is primarily fueled by sanderdust and a natural gas pilot light and has a maximum rated drying capacity of 67,000 bone-dry tons per year. Sanderdust is routed to the GFD through the GFD sanderdust feed bin, discussed in more detail in Section 2.1.6.

Dried furnish is routed with the dryer exhaust stream to two downstream cyclones for transfer to processing. The exhaust of each cyclone is combined and routed to a wet ESP for control of fine particulate emissions, followed by a regenerative thermal oxidizer for control of volatile organic compound emissions. The wet ESP was installed in 1997, and the regenerative thermal oxidizer was installed in 2003.

The GFD emissions unit is already equipped with state-of-the-art pollution control technology to control emissions of $PM_{10}$. As a result, the GFD emissions unit was excluded from further evaluation in the $PM_{10}$ Analysis.

### 2.1.3 Line 1 and Line 2 Presses (P1 and P2)

The Line 1 and Line 2 presses are hydraulically driven and heated by steam generated by the Line 1 and 2 boilers. The presses apply heat and pressure to activate the urea-formaldehyde resin and bond the wood fibers into a solid panel. The typical operating temperature range of either press is between 305 degrees Fahrenheit (°F) and 330°F. There are four roof vents on the Line 1 press and five on the Line 2 press. The Line 1 press was installed in 1965, and the Line 2 press was installed in 1969. Exhaust from each press vent is combined and routed to the regenerative catalytic oxidizer for control of volatile organic compound emissions.

### 2.1.4 Transfer to Line 1 Storage (C4)

Emissions unit MS represents a collection of material storage cyclone process units. The transfer to Line 1 storage cyclone process unit is designated within the MS emissions unit grouping. Reject from the reman area and trim material from the Line 1 Jenkins saw are pneumatically conveyed to the Line 1 storage area. Cyclone C4 is used to separate the reject and trim material, via centrifugal forces, from the exhaust stream for collection and reuse. The exhaust stream exiting the top of cyclone C4 is emitted to the atmosphere uncontrolled.

### 2.1.5 Line 1 Reject Bin (C23)

Emissions unit BF represents a collection of blending and forming cyclone process units. The Line 1 reject bin cyclone process unit is designated within the BF emissions unit grouping. Line 1 former, tipple, mat trim, and unloader rejected material is pneumatically conveyed to the Line 1 reject bin. Cyclone C23 is used to separate the reject material, via centrifugal forces, from the exhaust stream for collection and reuse. The exhaust stream exiting the top of cyclone C23 is emitted to the atmosphere uncontrolled.

### 2.1.6 Green Furnish Dryer Sanderdust Feed Bin (C47)

Stored sanderdust is pneumatically conveyed to the GFD sanderdust feed bin. Cyclone C47 is used to separate the sanderdust, via centrifugal forces, from the exhaust stream. Sanderdust dropping out of the cyclone is delivered to the GFD for drying. The exhaust stream exiting the top of cyclone C47 is routed to baghouse (BH) no. 21 for control of fine particulate emissions. The GFD sanderdust feed bin cyclone was installed in 1996.

### 2.1.7 Line 1 and Line 2 Board Coolers (BC1 and BC2)

Cured particleboard panels are cooled by the Line 1 and Line 2 board coolers after exiting the presses. Prior to stacking, cooled particleboard panels are sent to the finishing area for sanding and trimming to final product dimensions. There are four roof vents on the Line 1 board cooler and four vents on the Line 2 board cooler. Process exhaust from the Line 1 and 2 board coolers is routed through each applicable vent and emitted to the atmosphere uncontrolled.

### 2.1.8 Natural Gas in the Line 1 and 2 Dryers

There are two rotary dryers located on Line 1. The HEIL rotary core dryer (i.e., dedicated to drying furnish for the particleboard core) is heated by natural gas-fired combustion and supplemental flue gas from the Line 1 boiler. The HEIL rotary face dryer (i.e., dedicated to drying furnish for the particleboard face) is heated by natural gas-fired combustion and steam. The Line 1 dryers can dry furnish up to 115,200,000 square feet of furnish on a three-quarter-inch basis per year, and the maximum rated heat input capacity is approximately 3.5 MMBtu/yr.

Dried furnish leaving the Line 1 rotary core and face dryers is pneumatically conveyed to cyclone C9 and cyclone C10 for furnish removal and control of coarse particulate emissions, respectively. Process exhausts from cyclones C9 and C10 are routed to baghouses BH25 and BH26, respectively, for further control of fine particulate emissions.

There are also two rotary dryers located on Line 2. Both the MEC rotary core dryer and MEC rotary face dryer are heated by natural gas-fired combustion and steam. The Line 2 dryers can dry furnish up to 124,800,000 square feet of furnish on a three-quarter-inch basis per year, and the maximum rated heat input capacity is approximately 4.25 MMBtu/yr.

Similar to the Line 1 dryers, dried furnish leaving the Line 2 rotary core and face dryers is pneumatically conveyed to cyclones C14 and C15 for furnish removal and control of coarse particulate emissions, respectively. Process exhausts from cyclones C14 and C15 are routed to baghouses BH28 and BH29, respectively, for further control of fine particulate emissions.

Only the emissions associated with natural gas-fired combustion in the dryers contribute to 90 percent to the total facility $PM_{10}$ emissions rate (see emissions ranking process described in Section 2). As a result, only the emissions associated natural gas-fired combustion in each dryer are included for further evaluation in the Analysis.

## 2.2 Sources of $NO_X$ Emissions

A summary of the selected emission units and associated $NO_X$ emission rates to be evaluated in the Analysis are presented in Table 2-2 (attached). As shown in the table, only the Line 2 boiler and GFD are included for further evaluation in the $NO_X$ Analysis. All other emission units fall below the threshold of 90 percent contribution to the total facility $NO_X$ emissions rate.

## 2.3 Sources of $SO_2$ Emissions

A summary of the selected emission units and associated $SO_2$ emission rates to be evaluated in the Analysis are presented in Table 2-3 (attached). As shown in the table, only the Line 1 boiler, Line 2 boiler, and GFD are included for further evaluation in the $SO_2$ Analysis. All other emission units fall below the threshold of 90 percent contribution to the total facility $SO_2$ emissions rate.

## 2.4 Emission Unit Exhaust Parameters

A summary of the emissions unit exhaust parameters included in the Analysis is presented in Table 2-4 (attached). Emission units identified in the preceding sections as infeasible for control, as already equipped with state-of-the-art control, or otherwise exempt are not presented. These emissions units will not be evaluated further in this Analysis.

# 3 REGIONAL HAZE FOUR-FACTOR ANALYSIS METHODOLOGY

This Analysis has been conducted consistent with the Federal Guidance Document, which outlines six steps to be taken when addressing the four statutorily required factors included in the Analysis. These steps are described in the following sections.

## 3.1 Step 1: Determine Emission Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by

identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

## 3.2 Step 2: Selection of Emissions

Section 2 details the method for determining the emission units and emission rates to be used in the Analysis. Potential to emit emission rates were obtained from the existing permit review report. These emissions rates represent a reasonable projection of actual source operation in the year 2028.

## 3.3 Step 3: Characterizing Cost of Compliance (Statutory Factor 1)

Once the sources, emissions, and control methods have all been selected, the cost of compliance is estimated. The cost of compliance, expressed in units of dollars per ton of pollutant controlled ($/ton), describes the cost associated with the reduction of visibility-impairing pollutants. Specific costs associated with operation, maintenance, and utilities at the facility are presented in Table 3-1 (attached).

The Federal Guidance Document recommends that cost estimates follow the methods and recommendations in the Control Cost Manual. This includes the recently updated calculation spreadsheets that implement the revised chapters of the Control Cost Manual. The Federal Guidance Document recommends using the generic cost estimation algorithms detailed in the Control Cost Manual in cases where site-specific cost estimates are not available.

Additionally, the Federal Guidance Document recommends using the Control Cost Manual in order to effect an "apples-to-apples" comparison of costs across different sources and industries.

## 3.4 Step 4: Characterizing Time Necessary for Compliance (Statutory Factor 2)

Characterizing the time necessary for compliance requires an understanding of construction timelines, which include planning, construction, shake-down and, finally, operation. The time that is needed to complete these tasks must be reasonable, and does not have to be "as expeditiously as practicable…" as is required by the Best Available Retrofit Technology regulations.

## 3.5 Step 5: Characterizing Energy and Non-air Environmental Impacts (Statutory Factor 3)

Both the energy impacts and the non-air environmental impacts are estimated for the control measures that were costed in Step 3. These include estimating the energy required for a given control method, but do not include the indirect impacts of a particular control method, as stated in the Federal Guidance Document.

The non-air environmental impacts can include estimates of waste generated from a control measure and its disposal. For example, nearby water bodies could be impacted by the disposed-of waste, constituting a non-air environmental impact.

## 3.6 Step 6: Characterize the Remaining Useful Life of Source (Statutory Factor 4)

The Federal Guidance Document highlights several factors to consider when characterizing the remaining useful life of the source. The primary issue is that often the useful life of the control measure is shorter than the remaining useful life of the source. However, it is also possible that a source is slated to be shut down well before a control device would be cost effective.

# 4 $PM_{10}$ ANALYSIS

The Analysis for $PM_{10}$ emissions follows the six steps previously described in Section 3.

## 4.1 Step 1—Determine $PM_{10}$ Control Measures for Consideration

### 4.1.1 Baghouses

BHs, or fabric filters, are common in the wood products industry. In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to collect on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are one of the most common forms of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. The accumulated particles are periodically removed from the filter surface by a variety of mechanisms and are collected in a hopper for final disposition.

Typical new equipment design efficiencies are between 99 and 99.9 percent. Several factors determine fabric filter collection efficiency. These include gas filtration velocity, particle characteristics, fabric characteristics, and the cleaning mechanism. In general, collection efficiency increases with decreasing filtration velocity and increasing particle size. Fabric filters are generally less expensive than ESPs, and they do not require complicated control systems. However, fabric filters are subject to plugging for certain exhaust streams and do require maintenance and inspection to ensure that plugging or holes in the fabric have not developed. Regular replacement of the filters is required, resulting in higher maintenance and operating costs.

Certain process limitations can affect the operation of BHs in some applications. For example, exhaust streams with very high temperatures (i.e., greater than 500°F) may require specially formulated filter materials and/or render BH control infeasible. Additional challenges include the particle characteristics, such as materials that are "sticky" and tend to impede the removal of material from the filter surface. Exhaust gases that exhibit corrosive characteristics may also impose limitations on the effectiveness of BHs. In wood products applications it is expected that particle characteristics, specifically particle and exhaust moisture content, may limit the feasibility on implementation. However, for some sources, baghouses are considered technically feasible.

### 4.1.2 Wet Venturi Scrubbers

Wet scrubbers remove particulate from gas streams primarily by inertial impaction of the particulate onto a water droplet. In a venturi scrubber, the gas is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity, causing the water to shear into fine droplets. Particles in the gas stream then impact the water droplets. The entrained water droplets are subsequently removed from the gas stream by a cyclonic separator. Venturi scrubber control efficiency increases with increasing pressure drops for a given particle size. Control efficiency increases with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Control efficiencies are typically around 90 percent for particles with a diameter of 2.5 microns or larger.

It is important to note that although wet scrubbers mitigate air pollution concerns, they also generate a water pollution concern. The effluent wastewater and wet sludge stream created by wet scrubbers requires that the operating facility have a water treatment system and subsequent disposal system in place. These consequential systems increase the overall cost of wet scrubbers and cause important environmental impacts to consider.

As wet scrubbers become saturated with a pollutant it is necessary to discharge (blowdown) some scrubber liquid and add fresh water. A water treatment system of suitable size is necessary to handle the scrubber blowdown. The facility is not connected to a city sewer system. The facility is reliant on a closed-loop system via the process wastewater treatment pond. The amount of scrubber blowdown that would be created for an appropriately sized wet scrubber would likely overwhelm the existing system, but it is currently unknown. The facility reserves the right to re-evaluate the technical feasibility of implementing a wet venturi scrubber at the facility should the DEQ request clarification.

### 4.1.3 Electrostatic Precipitator

ESPs are used extensively for control of PM emissions. An ESP is a particulate control device that uses electrical force to move particles entrained with a gas stream onto collection surfaces. An electrical charge is imparted on the entrained particles as they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the corona that charges the particles, thereby allowing for their collection on the oppositely-charged collector walls. In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. Instead of the collection hoppers used by dry ESPs, wet ESPs utilize a drainage system and water treatment of some sort. In dry ESPs, the collectors are knocked, or "rapped," by various mechanical means to dislodge the collected particles, which slide downward into a hopper for collection.

Typical control efficiencies for new installations are between 99 and 99.9 percent. Older existing equipment has a range of actual operating efficiencies of 90 to 99.9 percent. While several factors determine ESP control efficiency, ESP size is the most important because it determines exhaust residence time; the longer a particle spends in the ESP, the greater the chance of collecting it. Maximizing electric field strength will maximize ESP control efficiency. Control efficiency is also

affected to some extent by particle resistivity, gas temperature, chemical composition (of the particle and gas), and particle size distribution.

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern as they reduce air pollution. Use of wet ESPs generates a wastewater and wet sludge effluent that requires treatment and subsequent disposal, thereby increasing the overall costs. Given the significant cost of compliance presented in Table 4-1 for dry ESP installations, the cost analyses for wet ESP were not completed (as they will be even higher).

## 4.2 Step 2—Selection of Emissions

See Sections 2.1 for descriptions of the $PM_{10}$ emission units and emission rates selected for the Analysis.

## 4.3 Step 3—Characterizing Cost of Compliance

Tables 4-2 through 4-5 present the detailed cost analyses of the technically feasible $PM_{10}$ control technologies included in the Analysis. Note the natural gas in the Line 1 and 2 dryer is already controlled by the baghouses and therefore, was not included in Table 4-2 (e.g., baghouse cost effectiveness derivation table). A summary of the cost of compliance, expressed in $/ton, is shown below in Table 4-1:

**Table 4-1**
**Cost of Compliance for $PM_{10}$**

| Emissions Unit | Emissions Unit ID | Cost of Compliance ($/ton) | | |
|---|---|---|---|---|
| | | BH | Dry ESP | Wet Venturi Scrubber |
| Line 1 and Line 2 Press Vents | P1 & P2 | $51,879 | $70,559 | $58,502 |
| Transfer to Line 1 Storage | C4 | $117,824 | $146,114 | $134,116 |
| Line 1 Reject Bin | C23 | $175,824 | $217,349 | $199,395 |
| GFD Sanderdust Feed Bin | C47 | $308,815 | $389,991 | $351,189 |
| Line 2 Board Cooler | BC2 | $489,913 | $653,159 | $568,770 |
| Line 1 Board Cooler | BC1 | $433,511 | $549,699 | $495,053 |
| Natural Gas in Line 2 Dryer | -- | -- | $3,745,701 | $3,115,161 |
| Natural Gas in Line 1 Dryer | -- | -- | $4,181,572 | $3,511,844 |

## 4.4 Step 4—Characterizing Time Necessary for Compliance

Several steps will be required before the control device is installed and fully operational. After selection of a control technology, all of the following will be required: permitting, equipment procurement, construction, startup and a reasonable shakedown period, and verification testing. It is anticipated that it will take up to 18 months to achieve compliance.

## 4.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

### 4.5.1 Energy Impacts

Energy impacts can include electricity and/or supplemental fuel used by a control device. Electricity use can be substantial for large projects if the control device uses large fans, pumps, or motors. BH control systems require significant electricity use to operate the powerful fans required to overcome the pressure drop across the filter bags. Dry ESPs are expected to require even more electricity than a BH, since high-voltage electricity is required for particle collection and removal. Dry ESPs also require powerful fans to maintain exhaust flow through the system. Similarly, wet venturi scrubbers and wet ESPs will use significant amounts of electricity to power large pumps used to supply water for the control device and the subsequent treatment process.

### 4.5.2 Environmental Impacts

Expected environmental impacts for BHs and dry ESPs include the management of materials collected by the control devices. For sources where this material is clean wood residuals, it may be possible to reuse the material in the production process. However, collected materials that are degraded or that contain potential contaminants would be considered waste materials requiring disposal at a landfill.

As mentioned above, wet venturi scrubbers and wet ESPs generate liquid waste streams, creating a water pollution issue. The effluent of wastewater and wet sludge generated by both control technologies will require the facility to have in place an appropriately sized water treatment system and subsequent waste disposal system and/or procedure. These systems increase the overall cost of installation and cause important environmental impacts to consider.

While none of the control technologies evaluated in the $PM_{10}$ Analysis would require the direct consumption of fossil fuels, another, less quantifiable, impact from energy use may result from producing the electricity (i.e., increased greenhouse gases and other pollutant emissions). In addition, where fossil fuels are used for electricity production, additional impacts are incurred from the mining/drilling and use of fossil fuels for combustion.

## 4.6 Step 6—Characterize the Remaining Useful Life

It is anticipated that the remaining life of the emissions units, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. No emissions units are subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the presumption is that the control system would be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emissions units.

# 5 $NO_X$ ANALYSIS

The Analysis for $NO_X$ emissions follows the six steps previously described in Section 3.

## 5.1 Step 1—Determine $NO_X$ Control Measures for Consideration

### 5.1.1 Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) systems have been widely employed for biomass combustion systems. SNCR is relatively simple because it utilizes the combustion chamber as the control device reactor, achieving control efficiencies of 25 to 70 percent. SNCR systems rely on the reaction of ammonia and nitric oxide (NO) at temperatures of 1,550 to 1,950°F to produce molecular nitrogen and water, common atmospheric constituents, in the following reaction:

$$4NO+4NH_3+ O_2 \rightarrow 4N_2+ 6H_2O$$

In the SNCR process, the ammonia or urea is injected into the combustion chamber, where the combustion gas temperature is in the proper range for the reaction. Relative to catalytic control devices, SNCR is inexpensive and easy to install, particularly in new applications where the injection points can be placed for optimum mixing of ammonia and combustion gases. The reduction reaction between ammonia and NO is favored over other chemical reactions at the appropriate combustion temperatures and is, therefore, a selective reaction. One major advantage of SNCR is that it is effective in combustion gases with a high particulate loading. Sanderdust combustion devices can produce exhaust that has a very high particulate loading rate from ash carryover to the downstream particulate control device. With use of SNCR, the particulate loading is irrelevant to the gas-phase reaction of the ammonia and NO.

One disadvantage of SNCR, and any control systems that rely on the ammonia and NO reaction, is that excess ammonia (commonly referred to as "ammonia slip") must be injected to ensure the highest level of control. Higher excess ammonia generally results in a higher $NO_X$ control efficiency. However, ammonia is also a contributor to atmospheric formation of particulate that can contribute to regional haze. Therefore, the need to reduce $NO_X$ emissions must be balanced with the need to keep ammonia slip levels acceptable. Careful monitoring to ensure an appropriate level of ammonia slip, not too high or too low, is necessary.

Additionally, in applications where SNCR is retrofitted to an existing combustion chamber (i.e., an existing boiler), substantial care must be used when selecting injection locations. This is because proper mixing of the injected ammonia cannot always be achieved in a retrofit, possibly due to space limitations inside the boiler itself. For this reason, in retrofit applications it is common to achieve control efficiencies toward the lower end (25 percent) of the SNCR control efficiency range previously mentioned. It is important to note that the Line 2 boiler has a small combustion chamber (common

among type "D" boilers). The small combustion chamber, as noted above, will make retrofitting difficult, if not impossible.

Sanderdust-fired burner applications present further challenges for use of SNCR control systems. It is unlikely that the burner, in both the Line 2 boiler and GFD, would have the residence time needed at the critical temperatures for the proper reduction reaction to take place. In order to determine the appropriate residence time for the reaction and to ensure enough residence time exists, additional studies would be necessary to conclude whether SNCR is a technically feasible control option. Another concern for SNCR implementation, on the GFD only, is that ammonia can darken or blacken certain wood species. It is unknown what impact ammonia would have on the wood species being used by Woodgrain for the period of time it would be exposed, the concentrations of ammonia slip, and at the elevated temperatures that occur in the GFD. Due to these concerns, SNCR is not considered an applicable technology with proven feasibility for the sanderdust combustion devices at the facility.

To further highlight that SNCR control technology is likely technically infeasible for sanderdust-fired burner applications, MFA conducted a search of the USEPA RACT/BACT/LEAR Clearinghouse database. MFA performed the search for the period between January 1, 2000 to January 1, 2020 for similar fuel-type combustion units. No instances of SNCR installations on sanderdust combustion devices were found. As a result, SNCR was excluded from further evaluation in the Analysis.

### 5.1.2 Selective Catalytic Reduction and Hybrid Systems

Unlike SNCR, selective catalytic reduction (SCR) reduces $NO_X$ emissions with ammonia in the presence of a catalyst. The major advantages of SCR technology are the higher control efficiency (70 to 90 percent) and the lower temperatures at which the reaction can take place (400°F to 800°F, depending on the catalyst selected). SCR is widely used for combustion processes, such as those using natural gas turbines, where the type of fuel produces a relatively clean combustion gas. In an SNCR/SCR hybrid system, ammonia or urea is injected into the combustion chamber to provide the initial reaction with $NO_X$ emissions, followed by a catalytic (SCR) section that further enhances the reduction of $NO_X$ emissions. The primary reactions that take place in the presence of the catalyst are:

$$4NO+4NH_3+ O_2 \rightarrow 4N_2+ 6H_2O$$

$$2NO_2+4NH_3+ O_2 \rightarrow 3N_2+ 6H_2O$$

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$$

SCR is not widely used with wood-fired combustion units because of the amount of particulate that is generated by the combustion of wood. If not removed completely, the particulate can cause plugging in the catalyst and can coat the catalyst, reducing the surface area for reaction. Another challenge with wood-fired combustion is the presence of alkali metals such as sodium and potassium, which are commonly found in wood but not in fossil fuels. Sodium and potassium will poison catalysts, and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorus and arsenic.

Because of the likelihood of catalyst deactivation through particulate plugging and catalyst poisoning, SCR and SNCR/SCR hybrid systems are considered to be technically infeasible for control of $NO_X$ emissions from wood-fired combustion units.

### 5.1.3 Low NOx Burner

Low $NO_X$ burners are a viable technology for a number of fuels, including sanderdust and natural gas. Low $NO_X$ burner technology is used to moderate and control, via a staged process, the fuel and air mixing rate in the combustion zone. This modified mixing rate reduces the oxygen available for thermal $NO_X$ formation in critical $NO_X$ formation zones, and/or decreases the amount of fuel burned at peak flame temperatures. These techniques are also referred to as staged combustion or sub-stoichiometric combustion to limit $NO_X$ formation.

Potential reductions in $NO_X$ emissions from the direct wood-fired burners (without add-on controls) are limited by the burner firebox geometry, air flow controls and burner zone stoichiometry, making retrofitting applications difficult. While these parameters can be optimized for $NO_X$ performance and still maintain acceptable combustion performance, it is expected that facilities are already operating in this manner due to routine maintenance and tuning of the burner systems.

In order to achieve effective $NO_X$ reductions from low $NO_X$ burners, a complete replacement of the boiler and dryer burner system would likely be required, including fans, air control systems, and firebox. The Federal Guidance Document identifies several criteria for selecting control measures in the Analysis, including emission reductions through improved work practices, retrofits for sources with no existing controls, and upgrades or replacements for existing, less effective controls. None of these criteria identify or recommend whole replacement of emission units. Based on the challenges retrofitting the burners and the Federal Guidance Document criteria, low $NO_X$ burners for the Line 2 boiler and GFD were excluded from further consideration in the Analysis.

## 5.2 Step 2—Selection of Emissions

See Sections 2.2 for descriptions of the $NO_X$ emission units and emission rates, respectively, selected for the Analysis.

## 5.3 Step 3—Characterizing Cost of Compliance

No technically feasible control technologies were identified for potential control of $NO_X$ emissions. Therefore, the cost of compliance is not applicable to this Analysis.

## 5.4 Step 4—Characterizing Time Necessary for Compliance

No technically feasible control technologies were identified for potential control of $NO_X$ emissions. Therefore, the time necessary for compliance is not applicable to this Analysis.

## 5.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

Since no technically feasible control technologies were identified for $NO_X$ emissions, there are no energy and non-air environmental impacts to characterize.

## 5.6 Step 6—Characterize the Remaining Useful Life

No technically feasible control technologies were identified for $NO_X$ emissions; therefore, no characterization of the remaining useful life is necessary for the Analysis.

# 6 $SO_2$ ANALYSIS

The Analysis for $SO_2$ emissions follows the six steps previously described in Section 3.

## 6.1 Step 1—Determine $SO_2$ Control Measures for Consideration

### 6.1.1 Dry Sorbent Injection

$SO_2$ scrubbers are control devices typically used on stationary utility and industrial boilers, especially those combusting high sulfur fuels such as coal or oil. $SO_2$ scrubbers are not common for wood-fired boiler applications because of the inherent low sulfur content of the fuel.

$SO_2$ scrubbers use a reagent to absorb, neutralize, and/or oxidize the $SO_2$ in the exhaust gas, depending on the selected reagent. In dry sorbent injection systems, powdered sorbents are pneumatically injected into the exhaust gas to produce a dry solid waste. As a result, use of dry sorbent injection systems requires downstream particulate control devices to remove the dry solid waste stream. This waste product, a mixture of fly ash and the reacted sulfur compounds, will require landfilling or other waste management. For sources with existing particulate control devices, retrofitting dry sorbent injection onto existing systems will increase the volume of fly ash and solid waste generated by the existing system.

Overall performance depends on the sorbent selected for injection and the exhaust gas temperature at the injection location. These parameters are driven in large part by the specific combustion unit configuration and space limitations. Control efficiencies for dry sorbent injection systems, including retrofit applications, range between 50 and 80 percent for control of $SO_2$ emissions. While higher control efficiencies can be achieved with dry sorbent injection in new installations or with wet $SO_2$ scrubber systems, the ease of installation and the smaller space requirements make dry sorbent injection systems preferable for retrofitting.

Dry sorbent injection systems introduce PM emissions into the exhaust stream, as mentioned above. This will cause increases to the particulate inlet loading of downstream particulate control devices. For

retrofit applications, it is likely that modification of the downstream existing particulate control device will be necessary in order to accommodate the increased particulate inlet loading. It is anticipated that this increased loading cannot be accommodated solely through modifications to the existing control device. Assuming that this is the case, additional particulate controls will be required, resulting in cost increases and further energy and environmental impacts.

In addition, dry sorbent injection systems are commonly applied to high sulfur content fuel combustion systems, such as coal-fired boilers but not wood-fired boilers. The sulfur content of wood is quite low when compared to coal. It is also not certain that the control efficiency range, stated above, would be achievable when implemented on the emission units included in this $SO_2$ Analysis because of the low concentration of sulfur in the exhaust streams.

Therefore, the installation of dry sorbent injection systems on the emission units included in this $SO_2$ Analysis is not considered to be a feasible control option. Moreover, the potential for higher particulate emissions, which contribute to visibility issues, also suggests that dry sorbent injection should not be assessed in this Analysis.

## 6.2 Step 2—Selection of Emissions

See Section 2.3 for a description of the $SO_2$ emissions used in the Analysis.

## 6.3 Step 3—Characterizing Cost of Compliance

No technically feasible control technologies were identified for potential control of $SO_2$ emissions. Therefore, the cost of compliance is not applicable to this Analysis.

## 6.4 Step 4—Characterizing Time Necessary for Compliance

No technically feasible control technologies were identified for potential control of $SO_2$ emissions. Therefore, the time necessary for compliance is not applicable to this Analysis.

## 6.5 Step 5—Characterizing Energy and non-Air Environmental Impacts

Since no technically feasible control technologies were identified for $SO_2$ emissions, there are no energy and non-air environmental impacts to characterize.

## 6.6 Step 6—Characterize the Remaining Useful Life

No technically feasible control technologies were identified for $SO_2$ emissions; therefore, no characterization of the remaining useful life is necessary for the Analysis.

# 7 CONCLUSION

This report presents cost estimates associated with installing control devices at the La Grande facility in order to reduce visibility-impairing pollutants in Class I areas and provides the Four Factor Analysis conducted consistent with available DEQ and USEPA guidance documents. Woodgrain believes that the above information meets the state objectives and is satisfactory for the DEQ's continued development of the SIP as a part of the Regional Haze program.

# LIMITATIONS

The services undertaken in completing this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, express or implied, is made. These services were performed consistent with our agreement with our client. This report is solely for the use and information of our client unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, or the use of segregated portions of this report.

# TABLES

# Table 2-1
## $PM_{10}$ Evaluation for Regional Haze Four Factor Analysis
## Woodgrain Millwork, Inc.— La Grande, Oregon

| Emission Unit(s) [1] | Emission Unit ID(s) | Current $PM_{10}$ Control Technology [1] | Pollution Control Device ID | Annual $PM_{10}$ Emissions [2] (tons/yr) | Control Evaluation Proposed? | Rationale for Exclusion from Control Evaluation | Emission Controls to be Evaluated |
|---|---|---|---|---|---|---|---|
| Green Furnish Dryer | GFD/C46 | Cyclones (x2), WESP, RTO | RTO | 8.04 | No | Already using state of the art pollution control equipment. | -- |
| Line 2 Press | P2 | RCO | RCO | 6.86 | Yes | -- | Baghouses, Venturi Scrubbers, Electrostatic Precipitator |
| Line 1 Press | P1 | RCO | RCO | 6.34 | Yes | -- | Baghouses, Venturi Scrubbers, Electrostatic Precipitator |
| Line 2 Boiler | B2 | Dry ESP | DESP | 5.11 | No | Emission Unit is directly regulated for filterable PM as a surrogate for metal under Boiler MACT, which became effective after July 31, 2013. Therefore, this emission unit meets EPA guidance for no further analysis. | -- |
| Transfer to Line 1 Storage Cyclone (MS) | C4 | -- | -- | 3.51 | Yes | -- | Baghouses, Venturi Scrubbers, Electrostatic Precipitator |
| Line 1 Reject Bin (BF) | C23 | -- | -- | 2.36 | Yes | -- | Baghouses, Venturi Scrubbers, Electrostatic Precipitator |
| Line 1 Boiler | B1 | Good Combustion Practices | -- | 1.40 | No | Emission Unit is directly regulated for filterable PM as a surrogate for metal under Boiler MACT, which became effective after July 31, 2013. Therefore, this emission unit meets EPA guidance for no further analysis. | -- |
| Green Furnish Dryer Sanderdust Feed Bin | C47 | Baghouse | BH21 | 1.34 | Yes | -- | Venturi Scrubbers, Electrostatic Precipitator |
| Line 2 Board Cooler | BC2 | -- | -- | 1.25 | Yes | -- | Baghouses, Venturi Scrubbers, Electrostatic Precipitator |
| Line 1 Board Cooler | BC1 | -- | -- | 1.15 | Yes | -- | Baghouses, Venturi Scrubbers, Electrostatic Precipitator |
| Natural Gas in Line 2 Dryer | -- | Baghouses | BH28 / BH29 | 0.26 | Yes | -- | Venturi Scrubbers, Electrostatic Precipitator |
| Natural Gas in Line 1 Dryer | -- | Baghouses | BH25 / BH26 | 0.21 | Yes | -- | Venturi Scrubbers, Electrostatic Precipitator |
| All Other Emission Units | Varies | Varies per Emission Unit | -- | 4.25 | No | These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated. | -- |

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

# Table 2-2
## $NO_X$ Evaluation for Regional Haze Four Factor Analysis
## Woodgrain Millwork, Inc.— La Grande, Oregon

| Emission Unit(s) [1] | Emission Unit ID(s) | Current $NO_X$ Control Technology [1] | Annual $NO_X$ Emissions [2] (tons/yr) | Control Evaluation Proposed? | Rationale for Exclusion from Control Evaluation | Emission Controls to be Evaluated |
|---|---|---|---|---|---|---|
| Line 2 Boiler | B2 | -- | 222 | Yes | -- | Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Low-NOx Burners |
| Green Furnish Dryer | GFD/C46 | -- | 145 | Yes | -- | Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Low-NOx Burners |
| All Other Emission Units | Varies | -- | 12.5 | No | These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated. | -- |

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

# Table 2-3
## $SO_2$ Evaluation for Regional Haze Four Factor Analysis
## Woodgrain Millwork, Inc.— La Grande, Oregon

| Emission Unit(s) [1] | Emission Unit ID(s) | Current $SO_2$ Control Technology [1] | Annual $SO_2$ Emissions [2] (tons/yr) | Control Evaluation Proposed? | Rationale for Exclusion from Control Evaluation | Emission Controls to be Evaluated |
|---|---|---|---|---|---|---|
| Line 2 Boiler | B2 | -- | 1.29 | Yes | -- | Dry Sorbent Injection |
| Green Furnish Dryer | GFD/C46 | -- | 0.34 | Yes | -- | Dry Sorbent Injection |
| Line 1 Boiler | B1 | -- | 0.26 | Yes | -- | Dry Sorbent Injection |
| All Other Emission Units | Varies | -- | 1.09 | No | These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated. | -- |

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

# Table 2-4
## Emissions Unit Input Assumptions and Exhaust Parameters
## Woodgrain Millwork, Inc. — La Grande, Oregon

| Emission Unit ID | Emission Unit Description | Pollution Control Device ID | Control Evaluation Proposed? (Yes/No) | | | Heat Input Capacity (MMBtu/hr) | Exhaust Parameters | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Exit Temperature (°F) | Density Factor | | Exit Flowrate | |
| | | | $PM_{10}$ (1) | $NO_X$ (2) | $SO_2$ (3) | | | Elevation | Temperature | (acfm) | (dscfm) |
| B1 | Line 1 Boiler | -- | No | No | Yes | 56.0 (4) | 448.0 (7) | 0.9053 (a) | 0.584 (b) | 18,924 (c) | 10,000 (7) |
| B2 | Line 2 Boiler | DESP | No | Yes | Yes | 80.0 (4) | 646.3 (8) | -- | -- | 30,925 (8) | 11,680 (8) |
| GFD/C46 | Green Furnish Dryer | RTO | No | Yes | Yes | 134 (d) | 240.7 (11) | -- | -- | 59,610 (11) | 34,468 (11) |
| P1 & P2 | Line 1 and Line 2 Press Vents | RCO | Yes | No | No | -- | 142 (7) | 0.9053 (a) | 0.881 (b) | 98,280 (c) | 78,371 (7) |
| C4 | Transfer to Line 1 Storage | C4 | Yes | No | No | -- | 70.0 (12) | 0.9053 (a) | 1.000 (b) | 44,184 (c) | 40,000 (13) |
| C23 | Line 1 Reject Bin | C23 | Yes | No | No | -- | 70.0 (12) | 0.9053 (a) | 1.000 (b) | 44,184 (c) | 40,000 (13) |
| C47 | GFD Sanderdust Feed Bin | BH21 | Yes | No | No | -- | 70.0 (12) | 0.9053 (a) | 1.000 (b) | 44,184 (c) | 40,000 (14) |
| BC1 | Line 1 Board Cooler | -- | Yes | No | No | -- | -- | -- | -- | 61,640 (15) | 53,000 (15) |
| -- | Line 1 Board Cooler - Roof Vent 1 | BC11 | -- | -- | -- | -- | 105.0 (16) | 0.9053 (a) | 0.938 (b) | 28,968 (c) | 24,600 (16) |
| -- | Line 1 Board Cooler - Roof Vent 2 | BC12 | -- | -- | -- | -- | 100.0 (16) | 0.9053 (a) | 0.946 (b) | 22,642 (c) | 19,400 (16) |
| -- | Line 1 Board Cooler - Roof Vent 3 | BC13 | -- | -- | -- | -- | 94.0 (16) | 0.9053 (a) | 0.957 (b) | 3,926 (c) | 3,400 (16) |
| -- | Line 1 Board Cooler - Roof Vent 4 | BC14 | -- | -- | -- | -- | 63.0 (16) | 0.9053 (a) | 1.013 (b) | 6,104 (c) | 5,600 (16) |
| BC2 | Line 2 Board Cooler | -- | Yes | No | No | -- | -- | -- | -- | 83,906 (15) | 71,791 (15) |
| -- | Line 2 Board Cooler - Roof Vent 1 | BC21 | -- | -- | -- | -- | 94.0 (16) | 0.9053 (a) | 0.957 (b) | 31,014 (c) | 26,861 (16) |
| -- | Line 2 Board Cooler - Roof Vent 2 | BC22 | -- | -- | -- | -- | 113.0 (16) | 0.9053 (a) | 0.925 (b) | 11,650 (c) | 9,755 (16) |
| -- | Line 2 Board Cooler - Roof Vent 3 | BC23 | -- | -- | -- | -- | 116.0 (16) | 0.9053 (a) | 0.920 (b) | 13,882 (c) | 11,564 (16) |
| -- | Line 2 Board Cooler - Roof Vent 4 | BC24 | -- | -- | -- | -- | 96.0 (16) | 0.9053 (a) | 0.953 (b) | 27,360 (c) | 23,611 (16) |
| -- | Natural Gas in Line 1 Dryer | BH25/BH26 | Yes | No | No | -- | -- | -- | -- | 91,226 (17) | 74,000 (17) |
| -- | Line 1 Core Dryer to Baghouse 25 | BH25 | -- | -- | -- | -- | 148.0 (16) | 0.9053 (a) | 0.872 (b) | 46,885 (c) | 37,000 (16) |
| -- | Line 1 Face Dryer to Baghouse 26 | BH26 | -- | -- | -- | -- | 115.0 (16) | 0.9053 (a) | 0.922 (b) | 44,340 (c) | 37,000 (16) |
| -- | Natural Gas in Line 2 Dryer | BH28/BH29 | Yes | No | No | -- | -- | -- | -- | 101,491 (17) | 82,332 (17) |
| -- | Line 2 Core Dryer to Baghouse 28 | BH28 | -- | -- | -- | -- | 148.0 (16) | 0.9053 (a) | 0.872 (b) | 52,051 (c) | 41,077 (16) |
| -- | Line 2 Face Dryer to Baghouse 29 | BH29 | -- | -- | -- | -- | 115.0 (16) | 0.9053 (a) | 0.922 (b) | 49,440 (c) | 41,255 (16) |

NOTES:

acfm = actual cubic feet per minute.

BH = baghouse.

DESP = dry electrostatic precipitator.

dscfm = dry standard cubic feet per minute.

GFD = green furnish dryer.

RCO = regenerative catalytic oxidizer.

RTO = regenerative thermal oxidizer.

(a) Elevation density factor = (1 - [6.73E-06] x [facility elevation above sea level {ft}]$^{5.258}$

Sanderdust maximum drying capacity (BDT/yr) = 2,785 (5)

(b) Temperature density factor = (530) / ([exhaust temperature {°F}] + 460)

(c) Exit flowrate (acfm) = (exit flowrate [scfm]) x (1 - [humidity ratio]) / ([elevation density factor] x [temperature density factor]); see reference (6).

(d) Heat input capacity (MMBtu/hr) = (sanderdust maximum drying capacity [BDT/yr]) x (default high heat value for wood/wood residuals [MMBtu/ton]) / (annual hours of operation [hrs/yr])

Sanderdust maximum drying capacity (BDT/yr) = 67,000 (4)

Default high heat value for wood/wood residuals (MMBtu/ton) = 17.48 (9)

Annual hours of operation (hrs/yr) = 8,760 (10)

References:

(1) See Table 2-1, $PM_{10}$ Evaluation for Regional Haze Four Factor Analysis.

(2) See Table 2-2, $NO_X$ Evaluation for Regional Haze Four Factor Analysis.

(3) See Table 2-3, $SO_2$ Evaluation for Regional Haze Four Factor Analysis.

(4) Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014. See Review Report.

(5) Elevation above sea level obtained from publicly available online references.

(6) Conservatively assumes no humidity ratio, and moisture and pressure density factors of 1.

(7) Information provided Woodgrain Millwork, Inc.

(8) Woodgrain Lumber Composites Maximum Achievable Control Technology (MACT) Emission Source Test Report prepared by Environmental Technical Services, Inc. dated November 13-15, 2019.

(9) Title 40 CFR Subchapter C Part 98 Subpart C. See Table C-1 "Default $CO_2$ Emission Factors and High Heat Values of Various Types of Fuel."

(10) Assumes continuous annual operation.

(11) Woodgrain Lumber Composites Compliance Source Test Report prepared by Environmental Technical Services, Inc. dated November 12, 2019.

(12) The process exhaust is at ambient conditions. Assumes 70°F as representative.

(13) Information provided Woodgrain Millwork, Inc. Assumes engineering estimate.

(14) The exit flowrate for Baghouse 21 is not known. As a result, the line 1 reject bin exit flowrate is assumed as a surrogate.

(15) Assumes the sum total of board cooler roof vent flowrates.

(16) Information provided in Table 3, "Source Parameters - Existing and Future" for Plywood and Composite Wood Products MACT Low-Risk Demonstration prepared by Golder Associates, Inc. dated April 2007.

(17) Assumes the sum total of dryer baghouse flowrates.

# Table 3-1
# Utility and Labor Rates
# Woodgrain Millwork, Inc.— La Grande, Oregon

| Parameter | Value (units) | | |
|---|---|---|---|
| **FACILITY OPERATIONS** | | | |
| Annual Hours of Operation | 8,760 | (hrs/yr) | (1) |
| Annual Days of Operation | 365 | (day/yr) | (1) |
| Daily Hours of Operation | 24 | (hrs/day) | (1) |
| **UTILITY COSTS** | | | |
| Electricity Rate | 0.057 | ($/kWh) | (2) |
| Natural Gas Rate | 3.99 | ($/MMBtu) | (2) |
| Water Rate | 0.22 | ($/gal) | (2) |
| Average Monthly Water Usage | 1,028 | (Mgal/mo) | (2) |
| Wastewater Treatment Rate | 2.47 | ($/Mgal) | (a) |
| Wood Fuel Rate | 0 | ($/ton) | (3) |
| Landfill Disposal Rate | 81.0 | ($/ton) | (2) |
| Compressed Air Rate | 0.0039 | ($/Mscf) | (b) |
| **LABOR COSTS** | | | |
| Maintenance Labor Rate | 24.35 | ($/hr) | (2) |
| Operating Labor Rate | 22.65 | ($/hr) | (2) |
| Supervisory Labor Rate | 29.25 | ($/hr) | (2) |
| Operating Labor Hours per Shift | 2 | (hrs/shift) | (6) |
| Maintenance Labor Hours per Shift | 1 | (hrs/shift) | (6) |
| Shifts per Day | 3 | (shifts/day) | (7) |

NOTES:

Mgal = thousand gallons.

MMBtu = million British thermal units.

Mscf = thousand standard cubic feet.

MWh = megawatt-hour.

(a) Wastewater treatment rate ($/Mgal) = (average wastewater treatment cost [$/mo]) / (average monthly water usage [Mgal/mo])

| | | |
|---|---|---|
| Average wastewater treatment cost ($/mo) = | 2,538.42 | (2) |

(b) Compressed air cost ($-2019/Mscf) = (compressed air cost [$-1998/Mscf]) / (1998 CEPCI annual index) x (2019 CEPCI annual index)

| | | |
|---|---|---|
| Compressed air cost ($-1998/Mscf) = | 0.0025 | (4) |
| 1998 CEPCI annual index = | 389.5 | (5) |
| 2019 CEPCI annual index = | 607.5 | (5) |

REFERENCES:

(1) Assumes continuous annual operation.

(2) Information provided by Woodgrain Millwork, Inc.

(3) Information provided by Woodgrain Millwork, Inc. The facility does not purchase wood fuel from offsite.

(4) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. Cost presented in section 1.5.1.8 assumed to be representative.

(5) See Chemical Engineering magazine, CEPCI section for annual indices.

(6) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.5.1.1 and 1.5.1.3. Conservatively assumes the minimum labor requirement of range presented.

(7) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.11. Assumes operator shifts per day as representative.

**Table 4-2**
**Cost Effectiveness Derivation for Baghouse Installation**
**Woodgrain Millwork, Inc.— La Grande, Oregon**

| Emission Unit ID | Emission Unit Description | Input Parameters | | Pollutant Removed by Control Device [a] (tons/yr) | Operating Parameter | |
|---|---|---|---|---|---|---|
| | | Exhaust Flowrate [1] (acfm) | $PM_{10}$ Annual Emissions Estimate [2] (tons/yr) | | Electrical Requirements [4] (kW) | Number of Filter Bags Required [4] |
| P1 & P2 | Line 1 and Line 2 Press Vents | 98,280 | 13.2 | 13.1 | 382 | 1,239 |
| C4 | Transfer to Line 1 Storage | 44,184 | 3.51 | 3.48 | 180 | 557 |
| C23 | Line 1 Reject Bin | 44,184 | 2.36 | 2.34 | 180 | 557 |
| C47 | GFD Sanderdust Feed Bin | 44,184 | 1.34 | 1.33 | 180 | 557 |
| BC2 | Line 2 Board Cooler | 83,906 | 1.25 | 1.24 | 328 | 1,058 |
| BC1 | Line 1 Board Cooler | 61,640 | 1.15 | 1.14 | 245 | 777 |

| Emission Unit ID | Emission Unit Description | Direct Costs | | | Total Indirect Costs [d] | Total Capital Investment [e] | Capital Recovery Cost (CRC) | | | | Direct Annual Costs | | | | | | | | Total Indirect Annual Costs [o] | Total Annual Cost [p] | Annual Cost Effectiveness [q] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Purchased Equipment Cost | | Total Direct Cost [c] | | | Control Device (CRC) [f] | Replacement Parts | | | Operating Labor | | Maintenance | | Utilities | | | Total Direct Annual Costs [14] | | | |
| | | Basic Equip./Services Cost [4] | Total [b] | | | | | Filter Bag Cost [4] | Bag Labor Cost [h] | Filter Bag (CRC) [i] | Operator Cost [j] | Supervisor Cost [k] | Labor Cost [j] | Material Cost [14] | Electricity Cost [l] | Compressed Air Cost [m] | Landfill Cost [n] | | | | |
| USEPA COST MANUAL VARIABLE | | A | B | DC | IC | TCI | $CRC_D$ | $C_B$ | $C_L$ | $CFC_B$ | -- | -- | -- | -- | -- | -- | -- | DAC | IAC | TAC | ($/ton) |
| P1 & P2 | Line 1 and Line 2 Press Vents | $332,342 | $392,164 | $682,366 | $176,474 | **$858,839** | $67,462 | $18,674 | $7,542 | $7,769 | $49,604 | $7,441 | $26,663 | $26,663 | $189,302 | $201,419 | $1,059 | $509,919 | $168,038 | **$677,957** | **$51,879** |
| C4 | Transfer to Line 1 Storage | $162,624 | $191,897 | $333,900 | $86,354 | **$420,254** | $33,011 | $8,402 | $3,391 | $3,495 | $49,604 | $7,441 | $26,663 | $26,663 | $89,105 | $90,553 | $282 | $293,805 | $116,044 | **$409,848** | **$117,824** |
| C23 | Line 1 Reject Bin | $162,624 | $191,897 | $333,900 | $86,354 | **$420,254** | $33,011 | $8,402 | $3,391 | $3,495 | $49,604 | $7,441 | $26,663 | $26,663 | $89,105 | $90,553 | $189 | $293,712 | $116,044 | **$409,756** | **$175,260** |
| C47 | GFD Sanderdust Feed Bin | $162,624 | $191,897 | $333,900 | $86,354 | **$420,254** | $33,011 | $8,402 | $3,391 | $3,495 | $49,604 | $7,441 | $26,663 | $26,663 | $89,105 | $90,553 | $107 | $293,630 | $116,044 | **$409,674** | **$308,815** |
| BC2 | Line 2 Board Cooler | $285,053 | $336,363 | $585,271 | $151,363 | **$736,634** | $57,863 | $15,943 | $6,441 | $6,633 | $49,604 | $7,441 | $26,663 | $26,663 | $162,681 | $171,961 | $100 | $451,746 | $153,551 | **$605,297** | **$489,913** |
| BC1 | Line 1 Board Cooler | $211,795 | $249,918 | $434,858 | $112,463 | **$547,321** | $42,992 | $11,712 | $4,730 | $4,873 | $49,604 | $7,441 | $26,663 | $26,663 | $121,641 | $126,327 | $92 | $363,303 | $131,108 | **$494,411** | **$433,511** |

See notes and formulas on following page.

**Table 4-2 (Continued)**
**Cost Effectiveness Derivation for Baghouse Installation**
**Woodgrain Millwork, Inc.— La Grande, Oregon**

NOTES:

(a) Pollutant removed by control device (tons/yr) = ($PM_{10}$ annual emissions estimate [tons/yr]) x (baghouse control efficiency [%] / 100)

| | | |
|---|---|---|
| Baghouse control efficiency (%) = | 99.0 | (3) |

(b) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (5).

(c) Total direct cost ($) = (1.74) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (5).

| | | |
|---|---|---|
| Site preparation cost, SP ($) = | 0 | (6) |
| Building cost, Bldg. ($) = | 0 | (6) |

(d) Total indirect cost ($) = (0.45) x (total purchased equipment cost [$]); see reference (5).

(e) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (5).

(f) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (7)

| | | |
|---|---|---|
| Control device capital recovery factor = | 0.0786 | (g) |

(g) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (8).

| | | |
|---|---|---|
| Interest rate (%) = | 4.75 | (9) |
| Baghouse economic life (yr) = | 20 | (10) |
| Filter bag economic life (yr) = | 4 | (11) |

(h) Bag replacement labor cost ($) = (total time required to change one bag [min/bag]) x (hr/60 min) x (number of filter bags required [bags]) x (maintenance labor rate [$/hr])

| | | |
|---|---|---|
| Total time required to change one bag (min/bag) = | 15 | (12) |
| Maintenance labor rate ($/hr) = | 24.35 | (13) |

(i) Filter bag capital recovery cost ($) = ([initial filter bag cost {$}] x [1.08] + [bag replacement labor cost {$}]) x (filter bag capital recovery factor); see reference (12).

| | | |
|---|---|---|
| Filter bag capital recovery factor = | 0.2804 | (g) |

(j) Operator or maintenance labor cost ($) = (staff hours per shift [hrs/shift]) x (staff shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (operator or maintenance labor rate [$/hr])

| | | |
|---|---|---|
| Operating labor hours per shift [hrs/shift] = | 2 | (13) |
| Maintenance labor hours per shift [hrs/shift] = | 1 | (13) |
| Shifts per day (shifts/day) = | 3 | (13) |
| Annual days of operation (days/yr) = | 365 | (13) |
| Operator labor rate ($/hr) = | 22.65 | (13) |
| Maintenance labor rate ($/hr) = | 24.35 | (13) |

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (14).

(l) Annual electricity cost ($) = (electricity rate [$/kWh]) x (total power requirement [kWh]) x (annual hours of operation [hrs/yr])

| | | |
|---|---|---|
| Electricity rate ($/kWh) = | 0.057 | (13) |
| Annual hours of operation (hrs/yr) = | 8,760 | (13) |

(m) Annual compressed air cost ($) = (compressed air rate [$/Mscf]) x (Mscf/1,000 scf) x (exhaust flowrate [acfm]) x (60 min/hr) x (annual hours of operation [hrs/yr])

| | | |
|---|---|---|
| Compressed air rate ($/Mscf) = | 0.0039 | (13) |
| Annual hours of operation (hrs/yr) = | 8,760 | (13) |

(n) Annual landfill cost ($) = (landfill disposal rate [$/ton]) x (pollutant removed by control device [tons/yr])

| | | |
|---|---|---|
| Landfill disposal rate ($/ton) = | 81.0 | (13) |

(o) Total indirect annual cost ($) = (0.60) x ([operator labor cost {$}] + [supervisor labor cost {$}] + [maintenance labor cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (14).

(p) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(q) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:


(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.

(2) See Table 2-1, $PM_{10}$ Evaluation for Regional Haze Four Factor Analysis.

(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-025) for baghouse (fabric filter), pulse-jet cleaned type issued July 15, 2003. Assumes minimum typical new equipment design efficiency.

(4) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. In the quote, costs and equipment requirements for three differently sized baghouses (5,000 cfm, 20,000 cfm, and 50,000 cfm) are presented. For the smallest exhaust flowrate above (MC4), these quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, installation of equipment, all concrete work (including excavation, engineering, plumbing, electrical construction), building/foundation upgrades, and permitting or licensing.

(5) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See Table 1.9 "Capital Cost Factors for Fabric Filters." The 1.18 factor includes instrumentation, sales tax, and freight.

(6) Conservatively assumes no costs associated with site preparation or building requirements.

(7) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.

(8) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.

(9) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.

(10) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.2.

(11) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. Typical bag filter life is 4 years.

(12) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.1.4.

(13) See Table 3-1, Utility and Labor Rates.

(14) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.

**Table 4-3**
**Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation**
**Woodgrain Millwork, Inc.— La Grande, Oregon**

| Emission Unit ID | Emission Unit Description | Input Parameters | | | Pollutant Removed by Control Device [a] (tons/yr) | Operating Parameter | | |
|---|---|---|---|---|---|---|---|---|
| | | Exhaust Flowrate [1] | | $PM_{10}$ Annual Emissions Estimate [2] (tons/yr) | | System Pressure Drop [4] (inch w.c.) | Total Collection Plate Area Estimate [b] ($ft^2$) | ESP Inlet Grain Loading [c] ($gr/ft^3$) |
| | | (acfm) | (scfm) | | | | | |
| P1 & P2 | Line 1 and Line 2 Press Vents | 98,280 | 78,371 | 13.2 | 13.1 | 6.00 | 31,348 | 3.6E-03 |
| C4 | Transfer to Line 1 Storage | 44,184 | 40,000 | 3.51 | 3.5 | 6.00 | 16,000 | 2.1E-03 |
| C23 | Line 1 Reject Bin | 44,184 | 40,000 | 2.36 | 2.34 | 6.00 | 16,000 | 1.4E-03 |
| C47 | GFD Sanderdust Feed Bin | 44,184 | 40,000 | 1.34 | 1.33 | 6.00 | 16,000 | 8.1E-04 |
| BC2 | Line 2 Board Cooler | 83,906 | 71,791 | 1.25 | 1.24 | 6.00 | 28,716 | 4.0E-04 |
| BC1 | Line 1 Board Cooler | 61,640 | 53,000 | 1.15 | 1.14 | 6.00 | 21,200 | 5.0E-04 |
| -- | Natural Gas in Line 2 Dryer | 101,491 | 82,332 | 0.26 | 0.25 | 6.00 | 32,933 | 6.7E-05 |
| -- | Natural Gas in Line 1 Dryer | 91,226 | 74,000 | 0.21 | 0.207 | 6.00 | 29,600 | 6.1E-05 |

| Emission Unit ID | Emission Unit Description | Direct Costs | | | Total Indirect Costs [f] | Total Capital Investment [g] | Capital Recovery Cost of Control Device [h] | Direct Annual Costs | | | | | | | | | | Total Indirect Annual Costs [s] | Total Annual Cost [t] | Annual Cost Effectiveness [u] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Purchased Equipment Cost | | Total Direct Cost [e] | | | | Operating Labor | | | Maintenance | | Utilities | | | | Total Direct Annual Costs [13] | | | |
| | | Basic Equip./Services Cost [5] | Total [d] | | | | | Operator Cost [j] | Supervisor Cost [k] | Coordinator Cost [l] | Labor Cost [m] | Material Cost [n] | Fan Electricity Cost [o] | Oper. Electricity Cost [p] | Compressed Air Cost [q] | Landfill Cost [r] | | | | |
| USEPA COST MANUAL VARIABLE | | A | B | DC | IC | TCI | $CRC_D$ | -- | -- | -- | -- | -- | -- | -- | -- | -- | DAC | IAC | TAC | ($/ton) |
| P1 & P2 | Line 1 and Line 2 Press Vents | $1,530,574 | $1,806,077 | $3,016,149 | $1,029,464 | **$4,045,613** | $317,785 | $49,604 | $7,441 | $16,535 | $6,416 | $18,061 | $52,920 | $30,153 | $201,419 | $1,070 | $383,617 | $538,442 | **$922,059** | **$70,559** |
| C4 | Transfer to Line 1 Storage | $753,216 | $888,795 | $1,484,287 | $506,613 | **$1,990,900** | $156,386 | $49,604 | $7,441 | $16,535 | $6,416 | $8,888 | $23,791 | $15,390 | $90,553 | $285 | $218,901 | $289,351 | **$508,252** | **$146,114** |
| C23 | Line 1 Reject Bin | $753,216 | $888,795 | $1,484,287 | $506,613 | **$1,990,900** | $156,386 | $49,604 | $7,441 | $16,535 | $6,416 | $8,888 | $23,791 | $15,390 | $90,553 | $191 | $218,807 | $289,351 | **$508,159** | **$217,349** |
| C47 | GFD Sanderdust Feed Bin | $753,216 | $888,795 | $1,484,287 | $506,613 | **$1,990,900** | $156,386 | $49,604 | $7,441 | $16,535 | $6,416 | $8,888 | $23,791 | $15,390 | $90,553 | $109 | $218,725 | $289,351 | **$508,076** | **$382,991** |
| BC2 | Line 2 Board Cooler | $1,306,724 | $1,541,935 | $2,575,031 | $878,903 | **$3,453,934** | $271,308 | $49,604 | $7,441 | $16,535 | $6,416 | $15,419 | $45,180 | $27,622 | $171,961 | $101 | $340,277 | $466,714 | **$806,991** | **$653,159** |
| BC1 | Line 1 Board Cooler | $959,952 | $1,132,743 | $1,891,682 | $645,664 | **$2,537,345** | $199,310 | $49,604 | $7,441 | $16,535 | $6,416 | $11,327 | $33,190 | $20,392 | $126,327 | $93 | $271,324 | $355,596 | **$626,920** | **$549,699** |
| -- | Natural Gas in Line 2 Dryer | $1,580,579 | $1,865,083 | $3,114,689 | $1,063,097 | **$4,177,786** | $328,167 | $49,604 | $7,441 | $16,535 | $6,416 | $18,651 | $54,648 | $31,678 | $207,999 | $21 | $392,991 | $554,465 | **$947,456** | **$3,745,701** |
| -- | Natural Gas in Line 1 Dryer | $1,420,710 | $1,676,438 | $2,799,651 | $955,569 | **$3,755,220** | $294,974 | $49,604 | $7,441 | $16,535 | $6,416 | $16,764 | $49,121 | $28,472 | $186,961 | $17 | $361,329 | $503,238 | **$864,567** | **$4,181,572** |

See notes and formulas on following page.

**Table 4-3 (Continued)**
**Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation**
**Woodgrain Millwork, Inc.— La Grande, Oregon**

NOTES:

(a) Pollutant removed by control device (tons/yr) = ($PM_{10}$ annual emissions estimate [tons/yr]) x (control efficiency [%] / 100)

| | | |
|---|---|---|
| Control efficiency (%) = | 99.0 | (3) |

(b) Total collection plate area estimate ($ft^2$) = (average specific collection area [$ft^2$/1,000 scfm]) x (exhaust flowrate [scfm])

| | | |
|---|---|---|
| Average specific collection area ($ft^2$/1,000 scfm) = | 400 | (3) |

(c) ESP inlet grain loading (gr/$ft^3$) = ($PM_{10}$ annual emissions estimate [tons/yr]) x (2,000 lb/ton) x (7,000 gr/lb) / (exhaust flowrate [acfm]) x (hr/60 min) / (annual hours of operation [hrs/yr])

| | | |
|---|---|---|
| Annual hours of operation (hrs/yr) = | 8,760 | (6) |

(d) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (7).

(e) Total direct cost ($) = (1.67) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (7).

| | | |
|---|---|---|
| Site preparation cost, SP ($) = | 0 | (8) |
| Building cost, Bldg. ($) = | 0 | (8) |

(f) Total indirect cost ($) = (0.57) x (total purchased equipment cost [$]); see reference (7).

(g) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (7).

(h) Capital recovery cost of control device($) = (total capital investment [$]) x (control device capital recovery factor); see reference (9).

| | | |
|---|---|---|
| Control device capital recovery factor = | 0.0786 | (i) |

(i) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^{economic life {yrs}}) / ([1 + {interest rate |%| / 100}]^{economic life {yrs}} - 1); see reference (10).

| | | |
|---|---|---|
| Interest rate (%) = | 4.75 | (11) |
| Dry ESP economic life (yr) = | 20 | (12) |

(j) Operator labor cost ($) = (operator hours per shift [hrs/shift]) x (operating shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (operator labor rate [$/hr])

| | | |
|---|---|---|
| Operator labor rate ($/hr) = | 22.65 | (6) |
| Operating labor hours per shift [hrs/shift] = | 2 | (6) |
| Shifts per day (shifts/day) = | 3 | (6) |
| Annual days of operation (days/yr) = | 365 | (6) |

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (13).

(l) Coordinator labor cost ($) = (1/3) x (operator labor cost [$]); see reference (13).

(m) Maintenance labor cost ($-1999) = (maintenance labor cost [$-1999]) / (1999 annual chemical engineering plant cost index) x (2019 annual chemical engineering plant cost index)

| | | |
|---|---|---|
| Maintenance labor cost ($-1999) | 4,125 | (13) |
| 1999 annual chemical engineering plant cost index = | 390.6 | (14) |
| 2019 annual chemical engineering plant cost index = | 607.5 | (14) |

(n) Maintenance material cost ($) = (0.01) x (total purchased equipment cost [$]); see reference (13).

(o) Annual fan electricity cost ($) = (0.000181) x (exhaust flowrate [acfm]) x (system pressure drop [inch w.c.]) x (annual hours of operation [hrs/yr]) x (electricity rate [$/kWh])

| | | |
|---|---|---|
| Annual hours of operation (hrs/yr) = | 8,760 | (6) |
| Electricity rate ($/kWh) = | 0.057 | (6) |

(p) Annual operating power electricity cost ($) = (1.94E-03) x (total collection plate area estimate [$ft^2$]) x (annual hours of operation [hrs/yr]) x (electricity rate [$/kWh])

| | | |
|---|---|---|
| Annual hours of operation (hrs/yr) = | 8,760 | (6) |
| Electricity rate ($/kWh) = | 0.057 | (6) |

(q) Annual compressed air cost ($) = (compressed air rate [$/Mscf]) x (Mscf/1,000 scf) x (exhaust flowrate [acfm]) x (60 min/hr) x (annual hours of operation [hrs/yr])

| | | |
|---|---|---|
| Compressed air rate ($/Mscf) = | 0.0039 | (6) |
| Annual hours of operation (hrs/yr) = | 8,760 | (6) |

(r) Annual landfill cost ($) = (4.29E-06) x (ESP inlet grain loading [gr/$ft^3$]) x (annual hours of operation [hrs/yr]) x (exhaust flowrate [acfm]) x (landfill disposal rate [$/ton]); see reference (13).

| | | |
|---|---|---|
| Annual hours of operation (hrs/yr) = | 8,760 | (6) |
| Landfill disposal rate ($/ton) = | 81.0 | (6) |

(s) Total indirect annual cost ($) = (0.60) x ([operator labor cost {$}] + [supervisor labor cost {$}] + [maintenance labor cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (13).

(t) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(u) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:


(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, $PM_{10}$ Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-028) for dry electrostatic precipitator, wire-plate type issued July 15, 2003. Assumes the typical collection area and minimum new equipment design control efficiency.
(4) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.2.3. Assumes the average system (including ductwork and collection system) pressure drop of range provided.
(5) PPC Industries Quotation no. 18048/18049 (Revision 0) dated September 12 and 13, 2018. MFA obtained two separate costs and equipment requirements for dry ESPs sized at 21,000 acfm and 51,000 acfm. For the smallest exhaust flowrate above (MC4), the quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, freight, mechanical construction, electrical work, excavation, building/foundation upgrades, and permitting or licensing.
(6) See Table 3-1, Utility and Labor Rates.
(7) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.16 "Capital Cost Factors for ESPs."
(8) Conservatively assumes no costs associated with site preparation or building requirements.
(9) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(10) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(11) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(12) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.4.2.
(13) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.21.
(14) See Chemical Engineering magazine, chemical engineering plant cost index section for annual indices.

**Table 4-4**
**Cost Effectiveness Derivation for Wet Venturi Scrubber Installation**
**Woodgrain Millwork, Inc.— La Grande, Oregon**

| Emission Unit ID | Emission Unit Description | Input Parameters | | | Pollutant Removed by Control Device [a] (tons/yr) | Operating Parameter | | |
|---|---|---|---|---|---|---|---|---|
| | | Exhaust Flowrate [1] | | $PM_{10}$ Annual Emissions Estimate [2] (tons/yr) | | Pump and Fan Power Requirement [b] (kW) | Inlet Grain Loading [c] ($gr/ft^3$) | Annual Water Demand [d] (gal/yr) |
| | | (acfm) | (scfm) | | | | | |
| P1 & P2 | Line 1 and Line 2 Press Vents | 98,280 | 78,371 | 13.2 | 13.1 | 313 | 3.6E-03 | 1,255,511 |
| C4 | Transfer to Line 1 Storage | 44,184 | 40,000 | 3.51 | 3.5 | 141 | 2.1E-03 | 379,405 |
| C23 | Line 1 Reject Bin | 44,184 | 40,000 | 2.36 | 2.34 | 141 | 1.4E-03 | 255,010 |
| C47 | GFD Sanderdust Feed Bin | 44,184 | 40,000 | 1.34 | 1.33 | 141 | 8.1E-04 | 144,696 |
| BC2 | Line 2 Board Cooler | 83,906 | 71,791 | 1.25 | 1.2 | 267 | 4.0E-04 | 127,364 |
| BC1 | Line 1 Board Cooler | 61,640 | 53,000 | 1.15 | 1.14 | 196 | 5.0E-04 | 118,147 |
| -- | Natural Gas in Line 2 Dryer | 101,491 | 82,332 | 0.26 | 0.25 | 323 | 6.7E-05 | 24,722 |
| -- | Natural Gas in Line 1 Dryer | 91,226 | 74,000 | 0.21 | 0.21 | 290 | 6.1E-05 | 20,207 |

| Emission Unit ID | Emission Unit Description | Direct Costs | | | Total Indirect Costs [h] | Total Capital Investment [i] | Capital Recovery Cost of Control Device [j] | Direct Annual Costs | | | | | | | | Total Indirect Annual Costs [q] | Total Annual Cost [r] | Annual Cost Effectiveness [s] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Purchased Equipment Cost | | Total Direct Cost [g] | | | | Operating Labor | | Maintenance | | Utilities | | | Total Direct Annual Costs [15] | | | |
| | | Basic Equip./Services Cost [e] | Total [f] | | | | | Operator Cost [l] | Supervisor Cost [m] | Labor Cost [l] | Material Cost [15] | Electricity Cost [n] | Water Usage Cost [o] | Wastewater Treatment Cost [p] | | | | |
| USEPA COST MANUAL VARIABLE | | A | B | DC | IC | TCI | $CRC_D$ | -- | -- | -- | -- | -- | -- | -- | DAC | IAC | TAC | ($/ton) |
| P1 & P2 | Line 1 and Line 2 Press Vents | $1,414,110 | $1,668,650 | $2,603,094 | $584,028 | **$3,187,122** | $301,888 | $49,604 | $7,441 | $26,663 | $26,663 | $155,162 | $272 | $3,100 | $268,905 | $495,595 | **$764,500** | **$58,502** |
| C4 | Transfer to Line 1 Storage | $721,752 | $851,667 | $1,328,601 | $298,083 | **$1,626,684** | $154,081 | $49,604 | $7,441 | $26,663 | $26,663 | $69,757 | $82 | $937 | $181,146 | $285,371 | **$466,517** | **$134,116** |
| C23 | Line 1 Reject Bin | $721,752 | $851,667 | $1,328,601 | $298,083 | **$1,626,684** | $154,081 | $49,604 | $7,441 | $26,663 | $26,663 | $69,757 | $55 | $630 | $180,812 | $285,371 | **$466,183** | **$199,395** |
| C47 | GFD Sanderdust Feed Bin | $721,752 | $851,667 | $1,328,601 | $298,083 | **$1,626,684** | $154,081 | $49,604 | $7,441 | $26,663 | $26,663 | $69,757 | $31 | $357 | $180,516 | $285,371 | **$465,887** | **$351,189** |
| BC2 | Line 2 Board Cooler | $1,295,382 | $1,528,551 | $2,384,539 | $534,993 | **$2,919,532** | $276,541 | $49,604 | $7,441 | $26,663 | $26,663 | $132,469 | $28 | $314 | $243,182 | $459,545 | **$702,727** | **$568,770** |
| BC1 | Line 1 Board Cooler | $956,321 | $1,128,459 | $1,760,396 | $394,961 | **$2,155,356** | $204,158 | $49,604 | $7,441 | $26,663 | $26,663 | $97,315 | $26 | $292 | $208,003 | $356,594 | **$564,597** | **$495,053** |
| -- | Natural Gas in Line 2 Dryer | $1,485,582 | $1,752,986 | $2,734,659 | $613,545 | **$3,348,204** | $317,146 | $49,604 | $7,441 | $26,663 | $26,663 | $160,231 | $5 | $61 | $270,668 | $517,296 | **$787,964** | **$3,115,161** |
| -- | Natural Gas in Line 1 Dryer | $1,335,241 | $1,575,584 | $2,457,911 | $551,454 | **$3,009,366** | $285,051 | $49,604 | $7,441 | $26,663 | $26,663 | $144,025 | $4 | $50 | $254,449 | $471,647 | **$726,097** | **$3,511,844** |

See notes and formulas on following page.

**Table 4-4 (Continued)**
**Cost Effectiveness Derivation for Wet Venturi Scrubber Installation**
**Woodgrain Millwork, Inc.— La Grande, Oregon**

NOTES:

(a) Pollutant removed by control device (tons/yr) = ($PM_{10}$ annual emissions estimate [tons/yr]) x (control efficiency [%] / 100)

| | | |
|---|---|---|
| Control efficiency (%) = | 99.0 | (3) |

(b) Pump and fan power requirement (kW) = (typical pump and fan power requirement [hp/1,000 cfm]) x (exhaust flowrate [acfm]) x (kW/1.341 hp)

| | | |
|---|---|---|
| Typical pump and fan power requirement (hp/1,000 cfm) = | 4.27 | (4) |

(c) Inlet grain loading (gr/ft$^3$) = ($PM_{10}$ annual emissions estimate [tons/yr]) x (2,000 lb/ton) x (7,000 gr/lb) / (exhaust flowrate [acfm]) x (hr/60 min) / (annual hours of operation [hrs/yr])

| | | |
|---|---|---|
| Annual hours of operation (hrs/yr) = | 8,760 | (5) |

(d) Water demand (gal/yr) = (control efficiency [%] / 100) x (inlet grain loading [gr/ft$^3$]) x (lb/7,000 gr) x (exhaust flowrate [scfm]) x (60 min/hr) x (annual hours of operation [hrs/yr]) / (mass fraction of solids in recirculation water) / (density of water [lb/gal]); see reference (6).

| | | |
|---|---|---|
| Control efficiency (%) = | 99.0 | (3) |
| Annual hours of operation (hrs/yr) = | 8,760 | (5) |
| Mass fraction of solids in recirculation water = | 0.20 | (6) |
| Density of water (lb/gal) = | 8.3 | (5) |

(e) Basic equipment/services cost ($) = (capital cost [$-2002/scfm]) x (exhaust flowrate [scfm]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 2002)

| | | |
|---|---|---|
| Capital cost ($-2002/scfm) = | 11.75 | (3) |
| Chemical engineering plant cost index for 2019 = | 607.5 | (7) |
| Chemical engineering plant cost index for 2002 = | 395.6 | (7) |

(f) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (8).

(g) Total direct cost ($) = (1.56) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (8).

| | | |
|---|---|---|
| Site preparation cost, SP ($) = | 0 | (9) |
| Building cost, Bldg. ($) = | 0 | (9) |

(h) Total indirect cost ($) = (0.35) x (total purchased equipment cost [$]); see reference (8).

(i) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (10).

(j) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (11).

| | | |
|---|---|---|
| Control device capital recovery factor = | 0.0947 | (k) |

(k) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^(economic life {yrs})) / ([1 + (interest rate |%| / 100)]^(economic life {yrs}) - 1); see reference (12).

| | | |
|---|---|---|
| Interest rate (%) = | 4.75 | (13) |
| Wet scrubber economic life (yr) = | 15 | (14) |

(l) Operator or maintenance labor cost ($) = (staff hours per shift [hrs/shift]) x (staff shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (staff labor rate [$/hr])

| | | |
|---|---|---|
| Operator labor rate ($/hr) = | 22.65 | (5) |
| Operating labor hours per shift (hrs/shift) = | 2 | (5) |
| Maintenance labor rate ($/hr) = | 24.35 | (5) |
| Maintenance labor hours per shift (hrs/shift) = | 1 | (5) |
| Shifts per day (shifts/day) = | 3 | (5) |
| Annual days of operation (days/yr) = | 365 | (5) |

(m) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (15).

(n) Annual electricity cost ($) = (fan and pump power requirement [kWh]) x (electricity rate [$/kWh]) x (annual hours of operation [hrs/yr])

| | | |
|---|---|---|
| Electricity rate ($/kWh) = | 0.057 | (5) |
| Annual hours of operation (hrs/yr) = | 8,760 | (5) |

(o) Annual water usage cost ($) = (annual water demand [gal/yr]) x (Mgal/1,000 gal) x (water rate [$/Mgal])

| | | |
|---|---|---|
| Water rate ($/Mgal) = | 0.22 | (5) |

(p) Annual wastewater cost ($) = (annual water demand [gal/day]) x (Mgal/1,000 gal) x (sewage treatment rate [$/Mgal])

| | | |
|---|---|---|
| Sewage treatment rate ($/Mgal) = | 2.47 | (5) |

(q) Total indirect annual cost ($) = (0.60) x ([operator labor cost [$]] + [supervisor labor cost [$]] + [maintenance labor cost [$]] + [maintenance material cost [$]]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (15).

(r) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(s) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:


(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, $PM_{10}$ Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-017) for venturi scrubber issued July 15, 2003. Assumes the maximum PM control efficiency and average capital cost.
(4) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.3.
(5) See Table 3-1, Utility and Labor Rates.
(6) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See section 2.5.5.1. Assumes lower end mass fraction of range in recirculation water since water evaporated is not accounted for.
(7) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices.
(8) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.8.
(9) Conservatively assumes no costs associated with site preparation or building requirements.
(10) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See equation 2.42.
(11) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(12) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(13) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(14) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See section 2.6.2.2.
(15) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.9.