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June 9, 2020

Ali Mirzakhalili, Air Quality Division Administrator
Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232
Ph: (503) 229 - 5696

Re: Regional Haze Four Factor Analysis; Pacific Wood Laminates, Inc.

Dear Mr. Mirzakhalili:

Pacific Wood Laminates, Inc. (PWL) is submitting the enclosed Regional Haze Four-Factor Analysis report as required by the Oregon Department of Environmental Quality (ODEQ) letter dated December 23, 2019. PWL was identified by ODEQ as a significant source of regional haze precursor emissions to the Kalmiopsis Wilderness in Oregon, thus requiring a four-factor analysis under the Regional Haze Program. Representatives of PWL participated in the informational webinar on the Regional Haze Program hosted by ODEQ on January 9, 2020. PWL is confident that the enclosed report meets the requirements of the four-factor analysis.

Please call (541) 254-1447 with any questions regarding this evaluation and report.

Certification
Based upon information and belief formed after a reasonable inquiry, I, as a responsible official of the above-mentioned facility, certify the information contained in this report is accurate and true to the best of my knowledge.

Sincerely,

Nolan Roy

Nolan Roy
Plywood and Veneer Operations Manager
Pacific Wood Laminates, Inc.

CC D Pei Wu, Oregon DEQ, via email at wu.d@deq.state.or.us

Enclosure

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Pacific Wood Laminates, Inc.

Prepared on behalf of:

Pacific Wood Laminates, Inc.
Brookings Facility
P.O. Box 820
819 Railroad Avenue
Brookings, OR 97415

Prepared by:

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June 11, 2020

EXECUTIVE SUMMARY

Bison Engineering, Inc. (Bison) was retained by Pacific Wood Laminates, Inc. (PWL) to prepare a four-factor analysis on potential regional haze precursor emission controls at their wood products facility in Brookings, Oregon. The four-factor analysis was requested by the Oregon Department of Environmental Quality (ODEQ) in a certified letter dated December 23, 2019.

The analysis relates to "Round 2" development of a State Implementation Plan (SIP) to address regional haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the four-factor analysis is to determine if there are potential emission control options at PWL that, if implemented, could be used to attain "reasonable progress" toward visibility goals in Oregon Class I areas.

The four-factor analysis was conducted to assess the control of emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and particulate matter less than ten micrometers (PM_{10}). The analysis calculates a cost effectiveness for adding equipment to control NO_x and PM_{10} emissions from the biomass-fired boiler and evaluates visibility impact from additional sources at PWL. The analysis ultimately showed that the cost effectiveness for additional emission controls is not considered economically feasible.

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ACRONYMS

BACT	Best Available Control Technology
BAER	Burned Area Emergency Response
BART	Best Available Retrofit Technology
BDT	Bone Dry Ton
BLM	Bureau of Land Management
BOP	Balance of Plant Cost
Btu	British Thermal Unit
CAA	Clean Air Act
CEMs	Continuous Emissions Monitor System
CEPCI	Chemical Engineering Plant Cost Index
CFR	Code of Federal Regulations
Control Cost Manual	EPA Air Pollution Control Cost Manual
dV	Deciview
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
F	Degrees Fahrenheit
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
IMPROVE	Interagency Monitoring of Protected Visual Environments
Klb or Mlb	Thousand pounds
km	Kilometer
lb	Pound
lb/MMBtu	Pounds per million British thermal units
lb/hr	Pounds per hour
LP	Louisiana-Pacific
m	Meter
MACT	Maximum Achievable Control Technology
MMBtu/hr	Million British thermal units per hour
MMBtu/MWh	Million British thermal units per megawatt-hour
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NCASI	National Council for Air and Stream Improvement
NEI	National Emissions Inventory
NH_3	Ammonia
$(NH_4)_2SO_4$	Ammonium sulfate
NPHR	Net plant heat input rate
NSR	Normalized stoichiometric ratio
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_x	Oxides of nitrogen
O&M	Operations and Maintenance Cost
ODEQ	Oregon Department of Environmental Quality
PCWP	Plywood and Composite Wood Products
PH1	Brookings Plywood Dutch-Oven Boiler 1 (Decommissioned)
PH2	Riley Hogged-Fuel Boiler (Operating)
PM	Particulate matter
PM_{10}	Particulate matter less than ten micrometers
PSEL	Plant Site Emission Limit
PWL	Pacific Wood Laminates
RBLC	RACT/BACT/LAER Clearinghouse
RCO	Regenerative Catalytic Oxidizer
RHR	Regional Haze Rule
Round 1	First planning period of the Regional Haze Program

Round 2	Second (current) planning period of the Regional Haze Program
RPG	Reasonable Progress Goal
RSCR	Regenerative Selective Catalytic Reduction
RTO	Regenerative Thermal Oxidizer
SCA	Specific Collection Area
SCL	South Coast Lumber
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
TAP	Toxic Air Pollutant
TBACT	Best Available Control Technology for Toxics
TPY	Tons per year
TSD	2008 Electric Generating Unit NO_x Mitigation Strategies Proposed Rule Technical Support Document
USFS	United States Forest Service
USGS	United States Geographical Survey
UTM	Universal Transverse Mercator
Wellons	Vendor Providing Control Equipment Quotes
WRAP	Western Regional Air Partnership

1.0 INTRODUCTION

1.1 Basis of the Four-Factor Analysis

The Federal Clean Air Act was amended in 1977 (42 USC 7401 *et. seq.*) to include a declaration by Congress claiming a national goal to be "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." (42 USC 7491(a)(1)). Plans and requirements were then codified in the Code of Federal Regulations (CFR), primarily within 40 CFR 51.308, to address that goal. The entire visibility program is now found in 40 CFR 51.300 – 309. These regulations require states to establish "reasonable progress goals" in order to "attain natural visibility conditions" by the year 2064 (40 CFR 51.308(d)(1)).

The federal visibility rules were revised in 1999 to specifically address regional haze. Since then, ODEQ has submitted several revisions of their SIP to the Environmental Protection Agency (EPA) for review and approval addressing visibility. During the first planning period of the Regional Haze Program (Round 1), ODEQ focused on NO_x, SO_2, and organic carbon emissions as the key pollutants contributing to regional haze and visibility impairment (77 FR 30454; see also 76 FR 38997 and 77 FR 50611). Organic carbon was determined to result primarily from wildfire, and at the time, ODEQ determined that PM from point sources contributed only a minimal amount to visibility impairment in Oregon Class I areas. Therefore, ODEQ focused on NO_x and SO_2 controls for point source emissions during the Round 1 reasonable progress analysis. ODEQ did not specifically review the PWL Brookings facility for visibility impairment contribution during the Round 1 reasonable progress analysis.

A second round of obligations (Round 2) is now under development. Round 2, or the second "planning period", requires an additional step toward reasonable progress in meeting the national goal of attaining natural visibility conditions in mandatory Class I areas by 2064. ODEQ chose facility-level emissions of NO_x, SO_2, and PM_{10} to be considered for potential reduction as part of the Round 2 reasonable progress analysis. These pollutants were selected based on monitoring data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) program [1] and is consistent with other Western Regional Air Partnership (WRAP)[1] states. ODEQ found that these three pollutants contribute to visibility impairments at Oregon Class I areas.

The Regional Haze Rule (RHR) as outlined in 40 CFR 51.308 *et seq*. identifies four factors which should be considered in evaluating potential emission control measures to make reasonable progress toward the visibility goal. These four factors are collectively known as the four-factor analysis and are as follows:

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[1] The Western Regional Air Partnership, or WRAP, is a voluntary partnership of states, tribes, federal land managers, local air agencies and the US EPA whose purpose is to understand current and evolving regional air quality issues in the West. https://www.wrapair2.org/

Factor 1. Cost of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of any existing source subject to such requirements

ODEQ contacted PWL by certified letter dated December 23, 2019, establishing the requirement to provide pollutant-specific information and an analysis of the above listed four factors for emission sources at the facility (Appendix A).

1.2 PWL Qualification

PWL was selected for the four-factor analysis based on a "Q/d" analysis. The "Q/d" analysis was referenced by ODEQ in the December 2019 Round 2 letter and is also used by EPA and all states as a screening tool to determine which sites will be analyzed for Round 2 of the Regional Haze program.

For Round 2, ODEQ has elected to look for reductions in SO_2 and NO_x (precursors to ammonium sulfate and ammonium nitrate) emissions. ODEQ has also included PM_{10} in the regional haze analysis. The sources chosen for the analysis are those facilities whose emissions-to-distance (from the Class I area) ratio exceeds the specified Q/d value as detailed in Table 1-1. If the Q/d evaluation exceeds 5 then the facility is required to perform a four-factor analysis. ODEQ evaluated Q/d qualification based on actual emissions and permit-based plant site emission limits (PSELs) where "Q" accounts for combined emissions of PM_{10}, SO_2 and NOx and "d" is the distance to the nearest mandatory Class I area. Both evaluations are included in the following table.[2]

Table 1-1: PWL Q/d Evaluation

Basis	Distance (km)	Emissions (tpy)				Q/d
	"d"	NOx	PM10	SO2	"Q"	
Actual Emissions (2017 NEI)	23.5	52.5	139.12	3.27	195	8.3
PSELs (Regional Haze Call-In)	23.5	76	189	29	294	12.5
PSELs (New Title V)	23.5	102	132	39	273	11.6

The Kalmiopsis Wilderness Area is approximately 23.5 kilometers (km) to the east and northeast of PWL and is the Class I area evaluated in the four-factor analysis. Actual emissions are based on the 2017 National Emissions Inventory (NEI) while the PSELs are based on the facility Title-V permit 08-0003-TV-01. The "Regional Haze Call-In" PSEL emissions listed in Table 1-1 were applicable at the time of the Q/d evaluation by ODEQ. PWL was issued a renewed Title V permit on December 30, 2019 with a combined PSEL

[2] Q/d analysis provided by ODEQ at https://www.oregon.gov/deq/FilterDocs/haze-QDFacilitiesList.pdf

for PM_{10}, SO_2 and NO_x of 273 tons. This is also included in the table. The PWL facility exceeds the Q/d requirement based on either actual or potential emissions.

The initial Q/d analysis used to prompt the four-factor analysis requirement was based on the emissions for the entire facility, but the four-factor analysis is focused on individual emission sources. The largest source of SO_2, NO_x and PM_{10} emissions at the facility is the Riley hogged-fuel boiler (Hogged-fuel boiler or PH2). The Q/d for the PH2 alone, using the new permit PSEL values, would also exceed the Round 2 threshold. The veneer dryers and plywood presses combined have about the same PM_{10} emissions as PH2, but they have only trace NOx or SO_2 emissions. A complete analysis of emission sources at the PWL facility is included in Section 4.4. This includes the criteria and selection of sources evaluated in the 4-factor analysis.

2.0 PROGRAM SUMMARY AND STATUS

As previously stated, the Regional Haze program is an attempt to attain 'natural' (nonanthropogenic) visibility conditions in all mandatory Class I areas by 2064.[3] The RHR itself was promulgated in 1999 with adjustments made in 2017. The rule has been implemented in incremental steps. The first step, sometimes referred to as the 1st planning period (Round 1), was a combination of the best available retrofit technology (BART) analysis and the four-factor analysis. This evaluated potential contributions toward Reasonable Progress Goals (RPGs) of the program. During this initial planning period BART applied to certain older facilities, and the four-factor program applied to 'larger' facilities that had the potential to impact visibility in a mandatory Class I area. PWL was excluded from both analyses under Round 1.

2.1 Oregon Initiatives

Round 1 regional haze requirements were implemented in a revision to the Oregon State Implementation Plan (SIP) which was submitted on December 20, 2010. The timeframe for Round 1 has since expired and the RHR now requires the implementation of Round 2. The second planning period is meant to show an incremental progress toward the national goal for the 10-year period of 2018 to 2028. Additional 10-year implementation periods will follow until the national goal is achieved (40 CFR 51.308(f)).

To implement the program fully, it was first necessary to measure regional haze (visibility and its constituents) in the identified Class I areas. This has been an ongoing effort via various ambient monitoring programs including the IMPROVE program [1]. This visibility monitoring program began in 1988 and continues to be a cooperative effort between EPA and various federal land managers (primarily the National Park Service and the US Forest Service). The IMPROVE station in the Kalmiopsis Wilderness is the representative dataset for this analysis of PWL's impact on visibility.

Figure 2-1 shows a summary of the IMPROVE monitoring data at the Kalmiopsis station for the years 2000 through 2018. Visibility degradation caused by anthropogenic (human-based) sources is defined as "impairment". Whereas visibility-reducing "haze" is caused by natural and anthropogenic sources.[4] The results of the IMPROVE monitor indicate that the primary pollutants accounting for the most impairment is ammonium sulfate [2]. Industrial SO_2 emissions are indicative of precursor ammonium sulfate impacts in the context of the Regional Haze program. The primary pollutant that accounts for most haze is organic carbon matter. Wildfire smoke is the major source of organic carbon matter in the air and is the largest contributor to light extinction at nearly all sites on the worst days. The Chetco Bar fire and other regional fires in Southern Oregon contributed heavily and exponentially to the wildfire smoke in 2017 and 2018 timeframe. During this time, PWL

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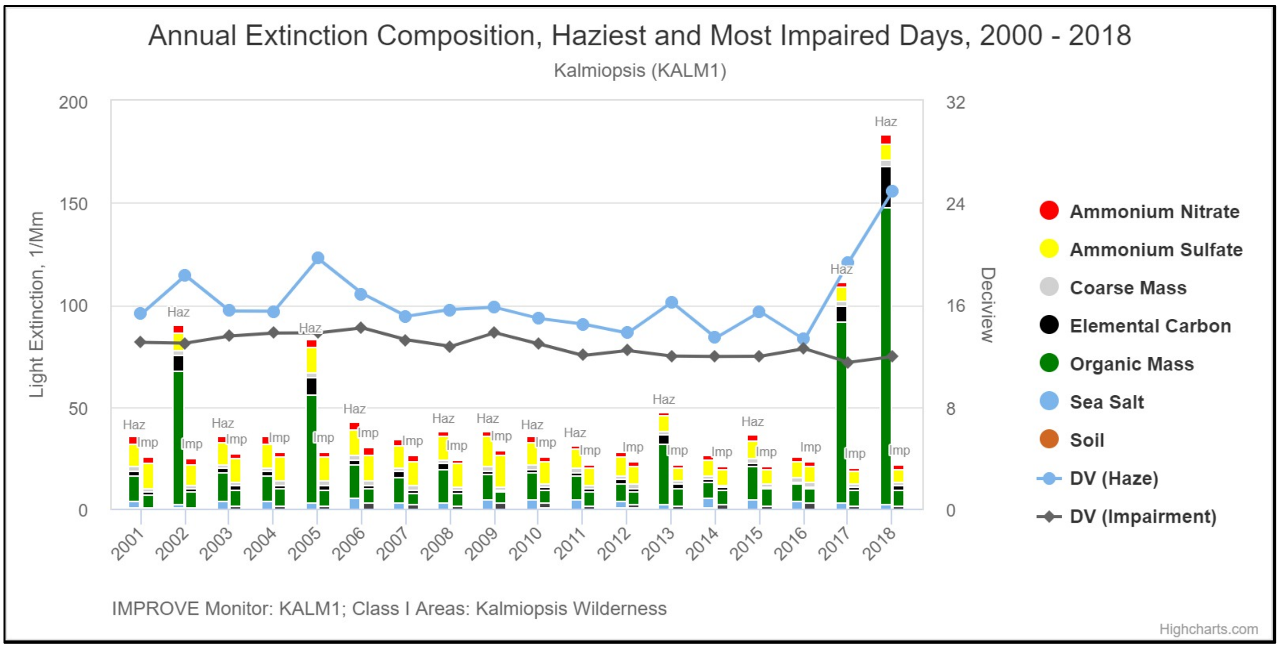
[3] A mandatory Class I area is usually a national park or wilderness area above a certain threshold size (4,000 or 5,000 acres) and in existence on or before August 7, 1977.
[4] Haze and impairment definitions are detailed for the IMPROVE monitoring network at http://vista.cira.colostate.edu/Improve/impairment/

and affiliated ownership experienced a complete loss of 14,000 acres of company fee timberlands that were managed in a sustained yield fashion. Additional wildfire losses include an estimated 200,000 acres of U.S. Forest Service (USFS), Bureau of Land Management (BLM), and other smaller private fee timberlands. Limited treatments were proposed by the USFS Burned Area Emergency Response (BAER) effort which included road and trail treatments, protection and safety treatments, and land treatments for cultural site protection and noxious and invasive plants.[5] The USFS's intent is do very little additional treatment (no active replanting -reforestation) to the USFS and BLM lands. The USFS states that "regeneration is expected to be slow in areas far from seed sources"[6] therefore it is likely that the burned area will be prone to naturally occurring wind erosion and large fugitive PM/PM_{10} emissions from the Chetco wind effect until regeneration has occurred. Once more, the large contribution of organic carbon is likely due to summer wildfire activity. Figure 4-3 (later in the report) provides the impact area of the Chetco Bar Fire in relation to PWL and the Kalmiopsis Wilderness.

Figure 2-1: IMPROVE Visibility Data for Kalmiopsis Wilderness Area



2.2 Federal Initiatives

Because this request for information arises from the RHR, it is important to understand the nature and purpose of the visibility protection program to properly implement the criteria that will lead to the selection of specific reasonable progress requirements.

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[5] Chetco Bar Fire BAER Request: https://www.fs.usda.gov/Internet/FSE_DOCUMENTS/fseprd563154.pdf
[6] USFS Talking Points – Chetco Bar Fire Recovery Efforts: https://www.fs.usda.gov/Internet/FSE_DOCUMENTS/fseprd585134.pdf

A visibility program aimed at attaining national visibility goals in mandatory Class I areas was authorized in Section 169A of the Clean Air Act (42 USC 7491). The national goals are to be attained by the year 2064, approximately 44 years from now. The rules which are to implement this goal of protecting visibility are found at 40 CFR 51, Subpart P (subsections 300 through 309). A review of Subpart P indicates the purpose and goals of the program as follows:

> "*The primary purposes of this subpart are . . .to assure **reasonable progress** toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment **results** from manmade air pollution. . .*" [40 CFR 51.300(a), emphasis added].

The visibility program may be thought of as the implementation of two sub-programs. One regarding new source review permitting and the other addressing "regional haze." Regional haze may be further broken down into the BART program and the reasonable progress program. The underlying reason for this review of the Brookings facility's emissions relates to reasonable progress achieved through the four-factor analysis.

In that regard, the RHR outlines what it refers to as "the core requirements" for the implementation of the regional haze goals. More specifically, 40 CFR 51.308(d)(1) states:

> "*For each mandatory Class I Federal area..., the State must establish goals... that provide for reasonable progress towards achieving natural visibility conditions. **The reasonable progress goals must provide for an improvement in visibility** for the most impaired days...*" [emphasis added]

The rules go on to provide the States with a list of what must be considered in developing reasonable progress. Among these details are the four-factor analysis that is outlined above in Section 1.1 and in the December 23, 2019 letter (Appendix A).

2.3 Applicability for Pacific Wood Laminates

Oregon is tasked with establishing a plan for "*reasonable progress*" in carrying out the incremental improvement to visibility. ODEQ notified PWL that they must "*complete a four factor analysis of potential additional controls of haze precursor emissions*" which will be evaluated by Oregon (and ultimately EPA) for applicability in establishing a set of specific, reasonable Oregon control strategies that create reasonable progress toward the 2064 goals.

The purpose of the program is to protect visibility by remedying, reducing, and preventing man-made impairments (or activities) over time in mandatory Class I areas. Reasonable progress expresses the notion that states must have implementation plans to approach the national goal by 2064 along a 'glide-path' of improvements to visibility, with certain exceptions. Based on the language contained in 40 CFR 51.308(d)(1), it can be ascertained that any activity, remedy or control (proposed or otherwise) that does not reasonably improve visibility in a mandatory Class I area is not a rational candidate for those reasonable progress goals [3]. That sentiment is confirmed in Section II.A EPA August 20, 2019 guidance [4]:

> *"The CAA and the Regional Haze Rule provide a process for states to follow to determine what is necessary to make reasonable progress in Class I areas. As a general matter, this process involves a state evaluating what emission control measures for its own sources, groups of sources, and/or source sectors are necessary in light of the four statutory factors, five additional considerations specified in the Regional Haze Rule, and possibly other considerations (e.g., visibility benefits of potential control measures, etc.). States have discretion to balance these factors and considerations in determining what control measures are necessary to make reasonable progress."*

As a result, an analysis that only considers one or more emission control options is not enough for inclusion into reasonable progress mandates unless those emission controls are expected to improve actual visibility in a Class I area in a discernible manner. It is neither necessary nor appropriate to include an emission control as part of a reasonable progress goal or plan without a reasonable expectation of a resulting improvement in regional haze as a direct result of the application of the control (i.e., a discernible improvement in deciviews[7] in a Class I area).

To that end, PWL has elected to not only analyze various control "options" utilizing four factors but has also included a qualitative analysis of impacts the Brookings facility may have on the closest Class I Area, the Kalmiopsis Wilderness Area. This was accomplished to determine if either the current configuration or future control options would fulfill the underlying need of the program to "***provide for an improvement in visibility***" at a mandatory Class I area [5].

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[7] The definition of a Deciview is as follows: Deciview haze index=10 ln (b_{ext}/10 Mm^{-1}), where b_{ext} is the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}). This is taken from the definition found in 40 CFR 51.301. There are, of course, numerous articles and explanations for the Deciview metric. One article may be found in the publication "IMPROVE," Volume 2, No. 1, April 1993 which was written by Pitchford and Malm, 1993. From a non-mathematical point of view, the change in Deciview of "1" is intended to represent a "just noticeable change" (or sometimes referred to as 'just discernible') in visibility regardless of the baseline visibility.

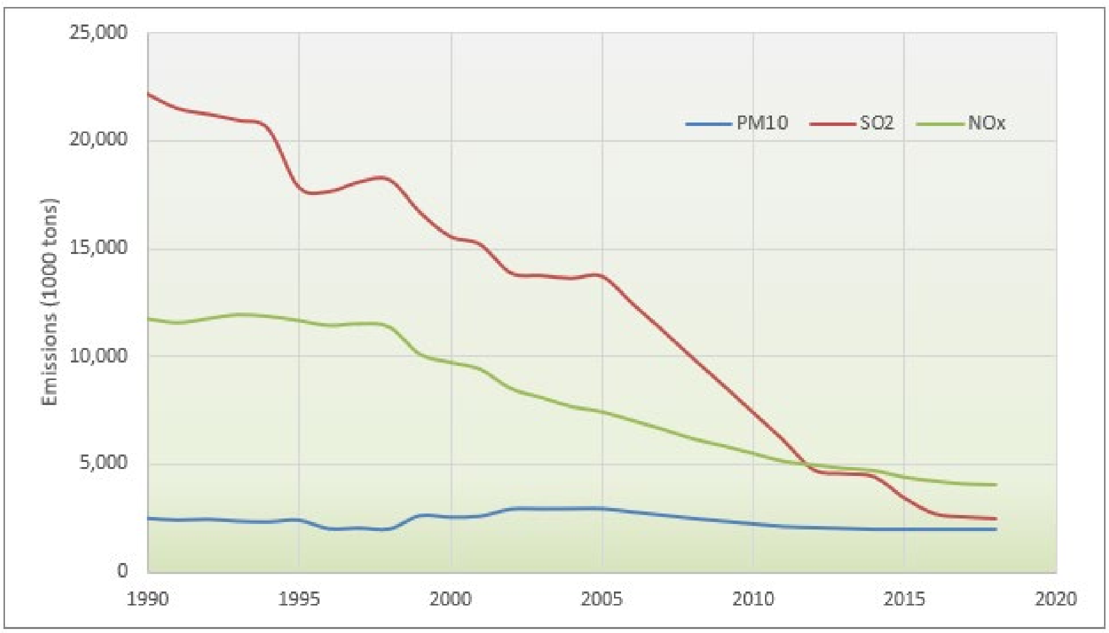
3.0 REASONABLE PROGRESS PERSPECTIVE

This report has so far provided a summary of the overall regional haze program and the nature of Round 2 implementation. It has also outlined the program's basic elements and background. The following section describes historical emissions trends and the efforts already taken to reduce emissions nationwide and statewide.

3.1 National Emissions

A national downward trend of industrial PM_{10}, SO_2, and NO_x emissions has been observed over the past 30-years. Reductions in emissions can be attributed to new requirements in the Federal Clean Air Act, advancements within state air quality regulatory programs, improvements in control technology, and the shutdown of industrial facilities. Figure 3-1 depicts national emissions trends from 1990 to 2018.[8]

Figure 3-1: National Industrial Emission Trends of PM_{10}, SO_2 and NOx (1990 – 2018)



Substantial reductions in industrial SO_2 and NOx emissions are observed since the promulgation of the RHR in 1999. National PM_{10} emissions from industrial sources have also decreased since 1999 however at a less significant rate. From a national perspective, emissions of SO_2 and NO_x are clearly on a fast-downward trend. National industrial emissions will not likely achieve "zero" by 2064, however their trendlines indicate that, if possible, emissions would be on a rapid pace to achieve zero well before the national

[8] National industrial emissions data obtained from the EPA National Emissions Inventory (NEI) National Emissions Trends database. https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data

goal year. Regardless, substantial reductions have occurred and will likely continue. Due to the emissions reductions that occur in response to other regulatory programs, national emissions contributing to regional haze are anticipated to continue to decline independently of the regional haze related programs.

Irrespective of the visibility impact of these emissions reductions, national SO_2 emissions from industrial sources in 2018 are about 16% of those emissions in 2000 and only about 11% of those emissions during the year the national goal was established (1990). Likewise, national NO_x emissions from industrial sources in 2018 are about 42% of those emissions in 2000 and 35% of those in 1990. Therefore, the reduction of industrial emissions in regard to the Regional Haze program appears to be well ahead of the goal year (2064) on a national level. As discussed below, emissions reductions in the state of Oregon are also on target to meet the goal.

Figures 3-2 and 3-3 provide emissions from categorized "source groups" represented within the NEI national trends data. This provides context into the amount each group contributes to the national total in relation to industrial emissions. The source groups are categorized as shown in Table 3-1.

Table 3-1: NEI Source Group Categorization

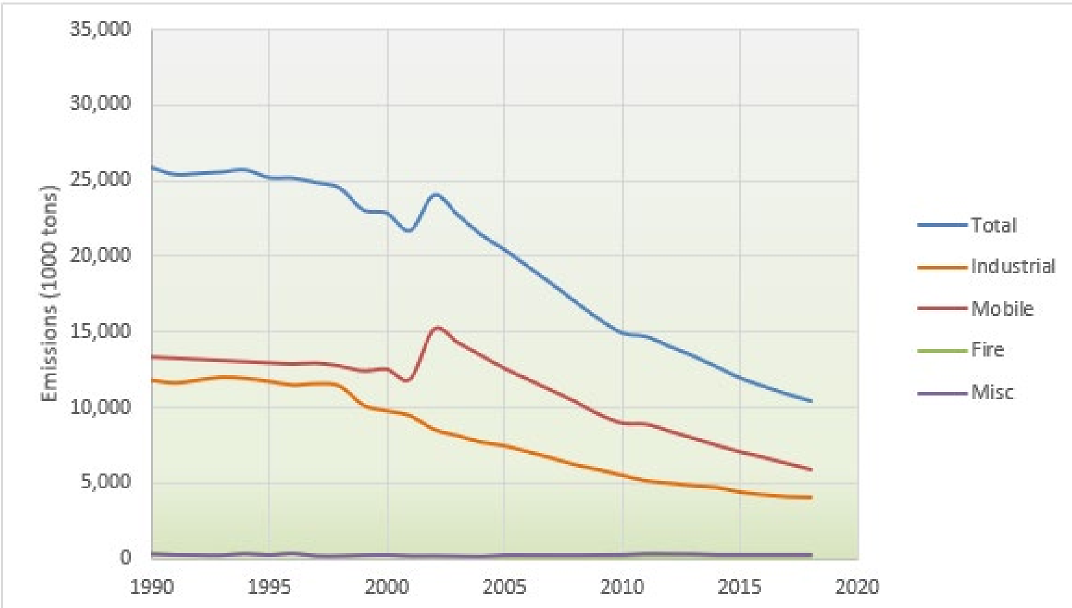
Category	NEI Source Groups
Industrial	Fuel Combustion: Electric Utility, Industrial, & Other Chemical and Allied Product Manufacturing Metals Processing Petroleum and Related Industries Other Industrial Processes Solvent Utilization Storage and Transport Waste Disposal and Recycling
Mobile/Transportation	Highway Vehicles Off-Highway
Fire	Wildfire Prescribed Burns
Miscellaneous[9]	Agriculture and Forestry Other Combustion (*excluding forest fires*) Catastrophic/Accidental Releases Repair Shops Health Services Cooling Towers Fugitive Dust

Figure 3-2 compares the contribution of NO_x emissions from each NEI source group to the national total. As previously stated, industrial emissions account for 36% - 47% of the total (40% in 2018). However, Figure 3-2 clearly indicates that the largest national

[9] Miscellaneous source categories are listed in Table 4.1-2 of the Procedures Document for National Emission Inventory Criteria Air Pollutants, 1985-1999. https://www.epa.gov/sites/production/files/2015-07/documents/aerr_final_rule.pdf

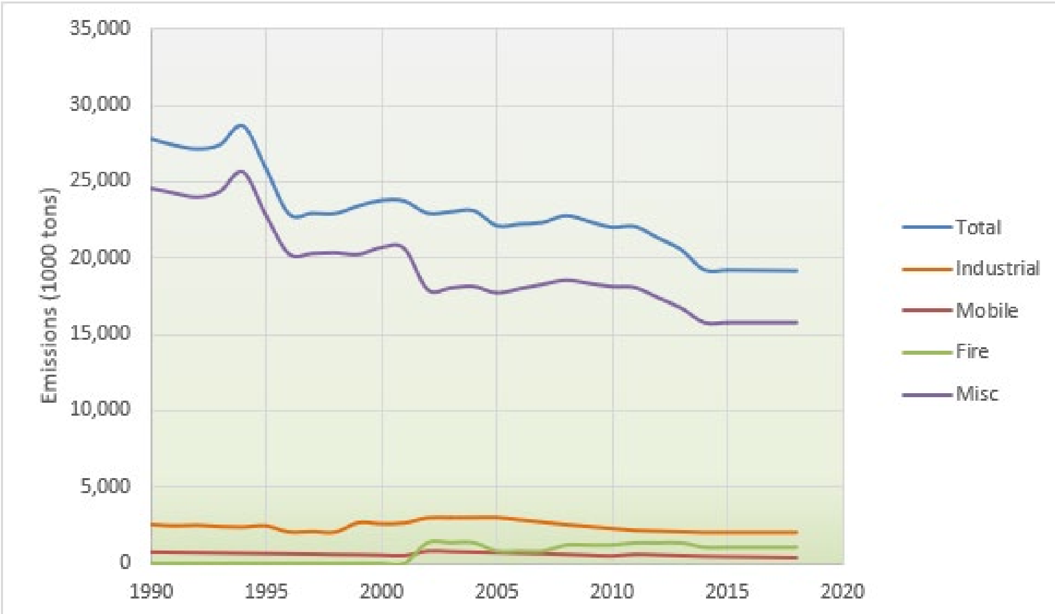
contributor of NO_x emissions originates from on-road vehicles and nonroad engines and vehicles. On-road vehicles include light-duty and heavy-duty gas and diesel vehicles. Nonroad engines and vehicles account for non-road gasoline and diesel engines, aircraft, marine vessels, railroads, and other sources.

Figure 3-2: National NO_x Emissions by Source Group



Similarly, Figure 3-3 compares the contribution of PM_{10} emissions across source groups. The discrepancy between group contributions is far more pronounced for this criteria pollutant where the "Miscellaneous" source group accounts for 78% to 90% of total PM_{10} emissions from 1990 – 2018 (82% in 2018). ***Conversely, industrial sources contribute only 9% - 14% of total PM_{10} emissions (11% in 2018).***

Figure 3-3: National PM_{10} Emissions by Source Group



Comparable trends are observed in Oregon emissions data as detailed in the next section. An important consideration for both datasets is to consider the resulting impact on visibility given the contribution of emissions to the national or state total. An enforced reduction to a minimally contributing factor (industrial source emissions) would intuitively result in a minimal effect on visibility in comparison to a reduction to the larger contributing factor (mobile/transportation sources and contributors to the miscellaneous source group).

3.2 Oregon Emissions

Also relevant to the discussion are the emissions trends of ODEQ's three primary compounds of concern in Oregon. As shown in Figure 3-4, there has also been a substantial reduction in industrial emissions within Oregon over the past 30-years.[10] Except for elevated PM_{10} emissions in 1999 and from 2002 – 2005, there has been a marked reduction in emissions of PM_{10}, NO_x, and SO_2 following a similar pattern to the national data. This demonstrates that Oregon has been contributing to achieving the national goal of the Regional Haze program.

Figure 3-5 provides historical emissions from all sources within Oregon. It also demonstrates an overall decrease in emissions of PM_{10}, NO_x, and SO_2. Historically, there has been more volatility in the trend of PM_{10} emissions, although the data still shows an

[10] Oregon industrial emissions data obtained from the EPA National Emissions Inventory (NEI) State Emissions Trends database. https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data

overall decreasing trend. SO_2 and NO_x emissions are marked by less volatility and a more consistent decrease.

Figure 3-4: Oregon Industrial Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)

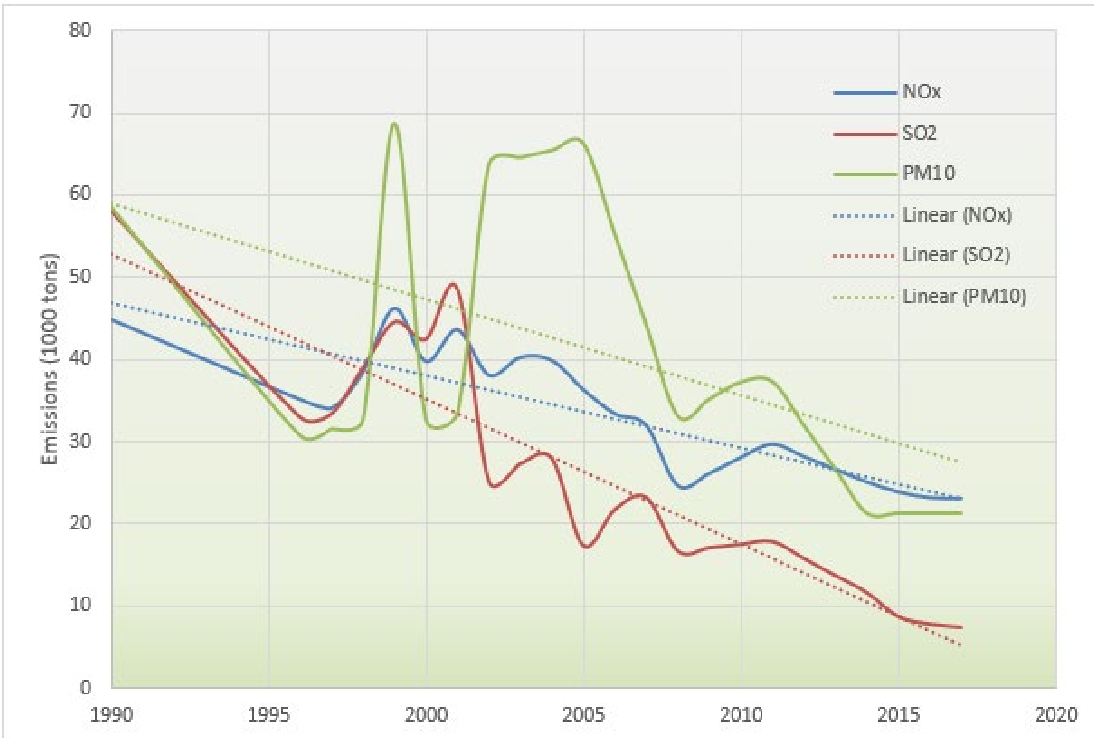


Figure 3-5: Oregon Total Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)

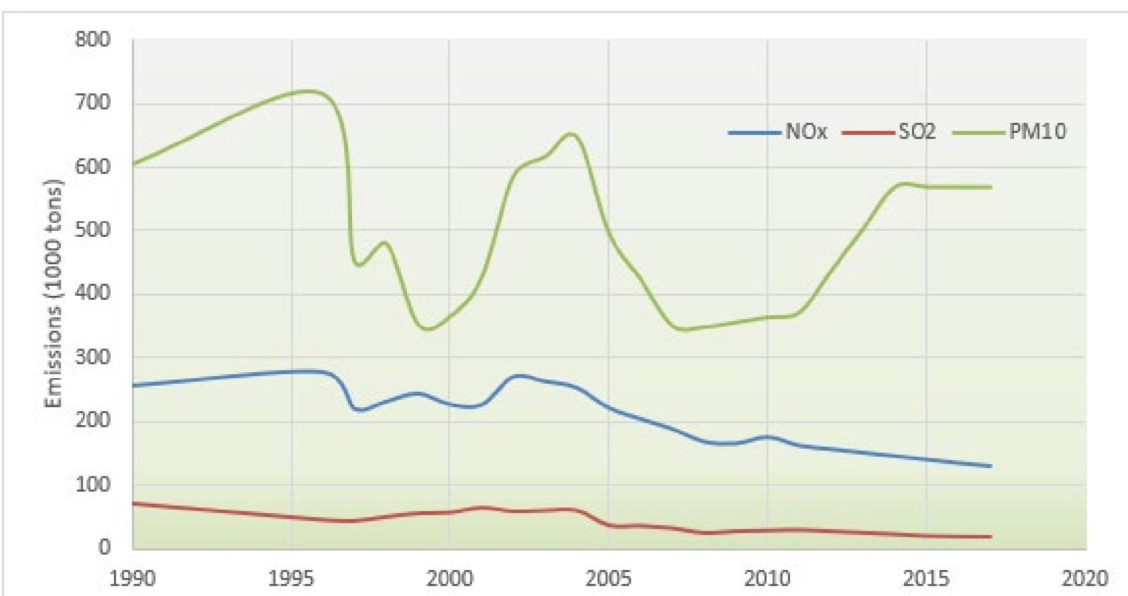
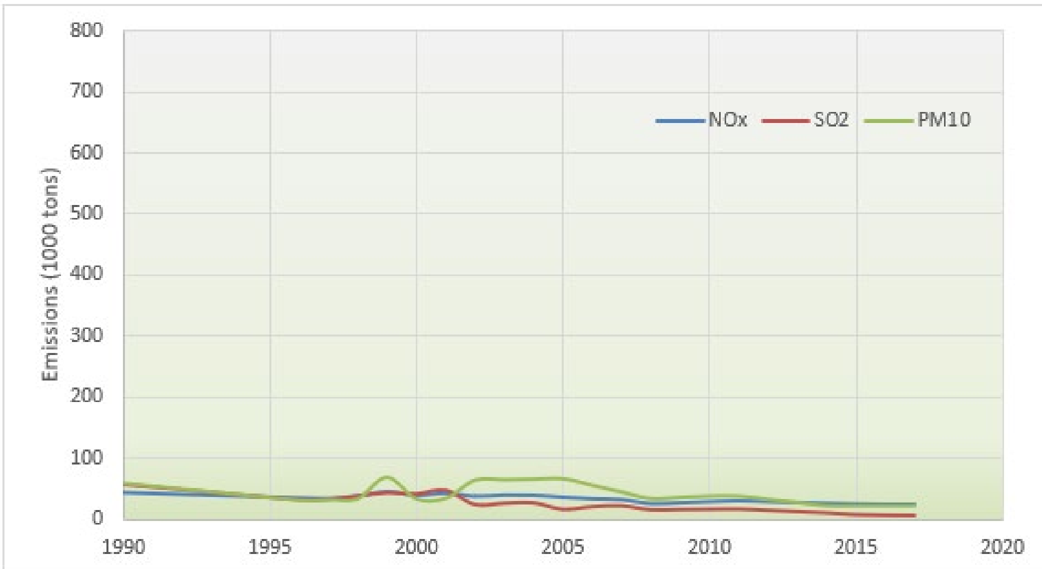


Figure 3-6 provides the industrial emissions data included in Figure 3-4 but in context to the scale of the y-axis in Figure 3-5. This demonstrates the contribution of industrial emissions to total state emissions.

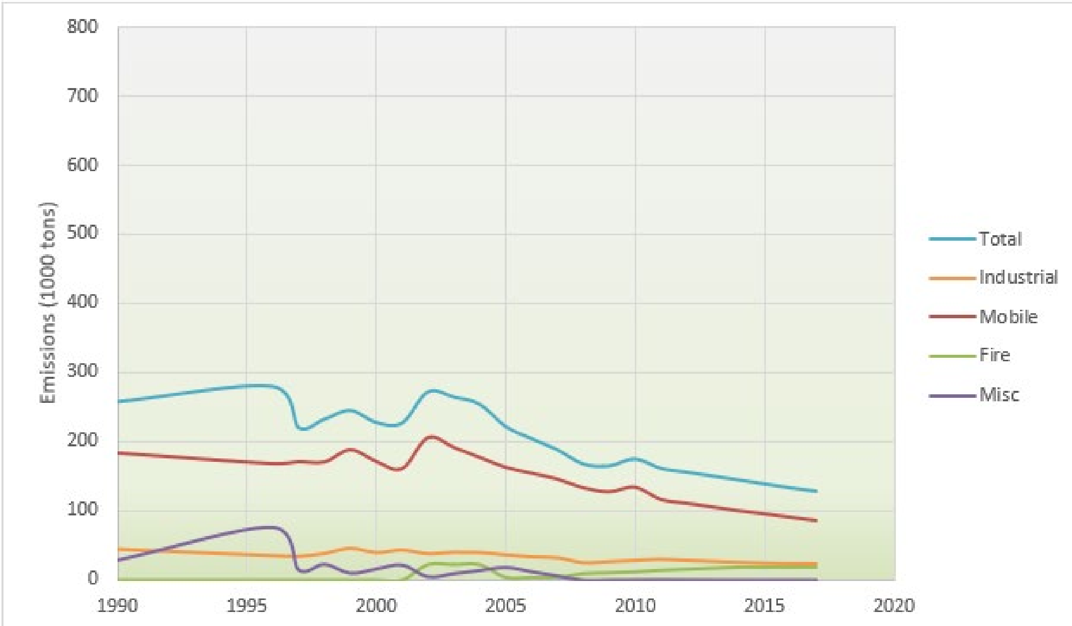
Figure 3-6: Oregon Industrial Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)



As shown in Figure 3-6, industrial emissions account for a very minimal contribution to the overall total emissions in Oregon. In 2017, industrial emissions only accounted for 18%, 39%, and 4% of total state emissions of NO_x, SO_2, and PM_{10}, respectively. This is further evaluated by assessing the contributions of all source groups as conducted with the national emissions data.

Figure 3-7 compares the contribution of NO_x emissions from each NEI source group to the Oregon total. As previously stated, industrial emissions account for 13% - 19% of the total emissions. Figure 3-7 clearly indicates that the largest state-wide contributor of NO_x emissions originates from on-road vehicles and nonroad engines as seen nationally. These emissions account for 60% – 80% of total NO_x emissions within Oregon.

Figure 3-7: Oregon NO_x Emissions by Source Group



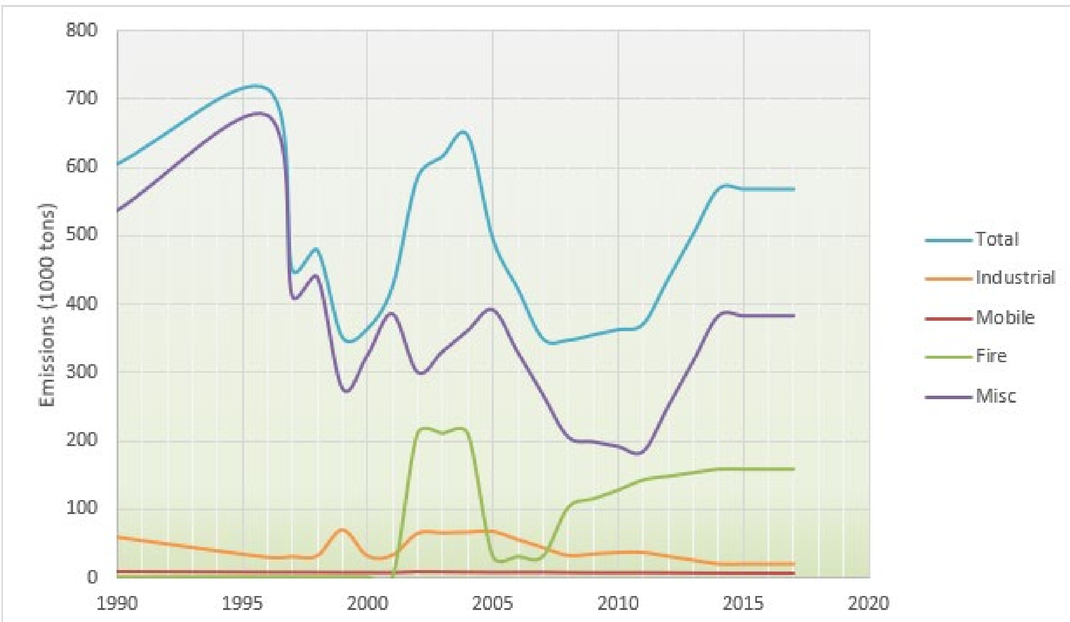
Similarly, Figure 3-8 compares the contribution of PM_{10} emissions across source groups to the state-wide total. Industrial sources again contribute minimally to total emissions (4% in 2017), whereas the "Miscellaneous" source group accounts for 48% to 95% of total PM_{10} emissions from 1990 – 2018 (82% in 2018). Additionally, wildfires and prescribed burn emissions have historically accounted for up to 39% of the total state-wide PM_{10} emissions. The Miscellaneous source group mirrors the same trend as the total state-wide emissions and is clearly the largest contributor. However, Figure 3-8 also indicates that wildfires provide substantial PM_{10} emissions to noticeably influence total emissions as shown from 2002 – 2005 and 2008 – 2017.

Wildfire has always impacted the Oregon landscape as it is a natural part of the health and ecology of forests in the region. However, the overall size and occurrence of wildfires in Oregon have increasing in the recent past as indicated in the Wildfire Smoke Trends and Associated Health Risks document produced by ODEQ.[11] The ODEQ Wildfire Smoke document continues to state that these increases are "due to past forestry practices, drought, hotter summers, warmer winters, reduced snowpack, and more human-caused fires." Ultimately, fire season is now longer than it has been historically. For context, based on the AQI system, Medford, OR has registered 18 days from 1985 – 2014 in the "unhealthy" category. In comparison, there have been 38 "unhealthy" days between 2015 – 2018. The historical influence of wildfire on total regional haze is indicated in Figure 2-1 for the years 2002, 2005, 2017, and 2018. In 2002, the Biscuit Fire burned almost 500,000 acres of the Rogue River-Siskiyou National Forest, accounting for the largest

[11] Wildfire Smoke Trends and Associated Health Risks: Bend, Klamath Falls, Medford and Portland – 1985 to 2018 (ODEQ Wildfire Smoke document): https://www.oregon.gov/deq/FilterDocs/smoketrends.pdf

wildfire Oregon recorded history. In 2005, The Blossom Complex fires and Simpson Fire impacted the area and regional visibility. Likewise, the Chetco Bar Fire burned roughly 190,000 acres of the Kalmiopsis Wilderness, and a Brookings wind effect aided in the spread of the fire to within five miles to the north of Brookings, OR. The 2018 wildfire season included five fires within the region, including the Hendrix, Miles, Klondike, Taylor Creek, and Garner Complex fires. While wildfire impact and influence are not included in the assessment of anthropogenic visibility impairment within the Regional Haze program, it is important to note the size, scale, and influence of wildfires on regional emissions and overall visibility impacts. The recent increase in wildfire size and occurrence is indicated by the data trends in Figures 2-1 and 3-8.

Figure 3-8: Oregon PM_{10} Emissions by Source Group



As discussed in the national emissions evaluation, it is important to consider the resulting impact on visibility given the contribution of emissions to the state total. An enforced reduction to a minimally contributing factor (i.e., industrial source emissions) would intuitively result in diminishing return or outcome on visibility improvement compared to a reduction to a larger contributing factor (i.e., contributors to the miscellaneous source group).

As stated on the ODEQ Air Quality website's home page, ***"about 90% of air pollution is generated from…everyday activities. Less than 10% is created from industry. Cars and trucks are the number one source of air pollution in Oregon."***[12]

[12] "Sources of air pollution" https://www.oregon.gov/deq/aq/pages/default.aspx

3.3 PWL Emissions and Perspective

As the current four-factor analysis request arises from the RHR, it is important to understand the nature and purpose of the visibility protection program to ascertain important criteria that will lead to the selection of specific reasonable progress requirements. The RHR program (under ODEQ and EPA) has not previously considered PWL's emissions as appropriate candidates for additional control under the reasonable progress criteria.

Current emissions from the PWL hogged-fuel boiler, dryers, and presses are standard for the facility and are not expected to increase during the foreseeable future. Conversely, PWL is continually striving to improve operational efficiency to improve production and reduce emissions. This is further discussed in Section 4.3. Therefore, PWL has concluded that the current baseline emissions of PM_{10}, SO_2 and NO_x selected from the 2017 NEI database are a reasonable estimate for the ongoing emissions from the facility for the purposes of RHR analyses.

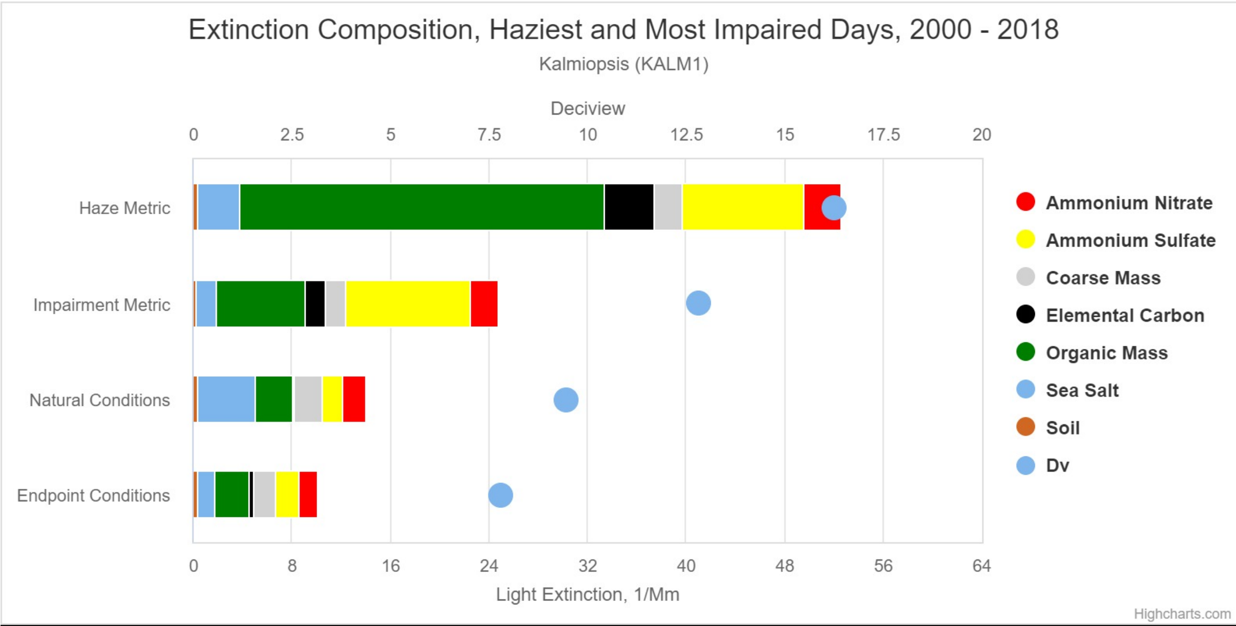
3.4 Emissions vs Visibility Impairment Analysis

In order to consider the results of a four-factor analysis as described by the RHR, there must be first and foremost a reasonable probability of an actual improvement in visibility impairment from emissions reductions from PWL facility sources. This analysis relies on actual visibility data collected at the Kalmiopsis Wilderness.

As previously shown in Figure 2-1, IMPROVE monitoring shows that the primary pollutant accounting for the most anthropogenic (human-caused) visibility degradation is ammonium sulfate [2]. The primary pollutant that accounts for the most non-anthropogenic visibility degradation is organic carbon matter. Wildfire smoke is the major source of organic carbon matter in the air.

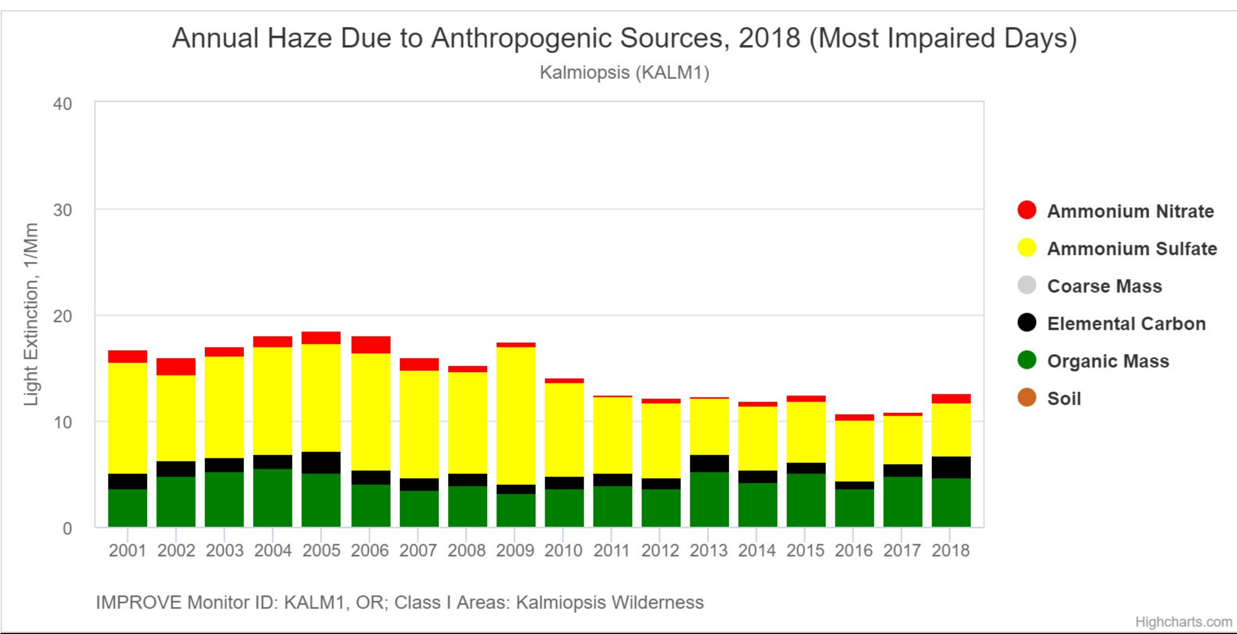
Figure 3-9 indicates a similar representation of haze and impairment contributions by providing the extinction composition by deciview for each metric [6]. Clearly, organic mass dominates the haze metric while ammonium sulfate provides the majority of the impairment metric. As stated previously, visibility degradation caused by anthropogenic (human-based) sources is defined as "impairment". Organic mass is the second largest contributor to impairment as indicated by Figure 3-9. However, it is important to note that ammonium nitrate accounts for a minimal contribution to anthropogenic impairment. PWL is a source of precursor emissions of organic mass (PM_{10}) and ammonium nitrate (NO_2) but is not a large contributor of any precursors to ammonium sulfate formation (SO_2).

Figure 3-9: IMPROVE Extinction Composition for Kalmiopsis Wilderness



Additionally, Figure 3-10 illustrates annual impairment composition in the Kalmiopsis Wilderness. Again, ammonium sulfate provides the largest contribution to anthropogenic visibility impairment.

Figure 3-10: IMPROVE Annual Haze Composition Due to Anthropogenic Sources for Kalmiopsis Wilderness



4.0 PACIFIC WOOD LAMINATES PERSPECTIVE

4.1 Facility Information

PWL owns and operates a plywood and laminated veneer lumber manufacturing plant (facility) in Brookings, Oregon. The facility is regulated under the ODEQ Title V Operating Permit Number 08-0003-TV-01 which was renewed on December 30, 2019.

As described in the Title V Permit Review Report, the facility produces plywood and laminated veneer lumber. The facility imports the veneer from other facilities and does not process logs. Steam generation from the hogged-fuel boiler provides heating for the veneer drying process and the plywood presses. The hogged-fuel boiler utilizes some sander dust and ply trim for fuel; however, most of the woody biomass fuel (hogged fuel) is imported from other plants. PWL produces approximately 85% plywood and 15% laminated veneer lumber. The emissions from the manufacturing processes are the same for plywood and laminated veneer lumber. Laminated veneer lumber also enters a secondary process on-site which includes finger jointing, molding cutting, edge gluing and painting.

4.2 Facility Location

The PWL facility is located in the city of Brookings, Oregon at 819 Railroad Avenue. The facility boundary is within approximately 0.2 kilometers (km) of the Pacific Ocean coastline and approximately 8.5 km from the boarder with the State of California. The Universal Transverse Mercator (UTM) coordinates for the site are Zone 10, Easting 393,381 meters (m), and Northing 4,656,157 m[13]. The facility is at an elevation of approximately 30 m above mean sea level.

Oregon has 12 Class I areas. The closest Class I airshed to the PWL facility is the Kalmiopsis Wilderness which lies 23.5 km northwest of Brookings, Oregon. Figures 4-1 and 4-2 shows the facility location in relation to the Kalmiopsis Wilderness Class I area. Figure 4-3 indicates the location of PWL to the Kalmiopsis Wilderness as well as the 2017 Chetco Bar Fire impact area.

[13] Site coordinates based on boiler stack location, as shown in Google Earth.

Figure 4-1: PWL Proximity to Kalmiopsis Wilderness Area

Figure 4-2: Facility Location in Oregon

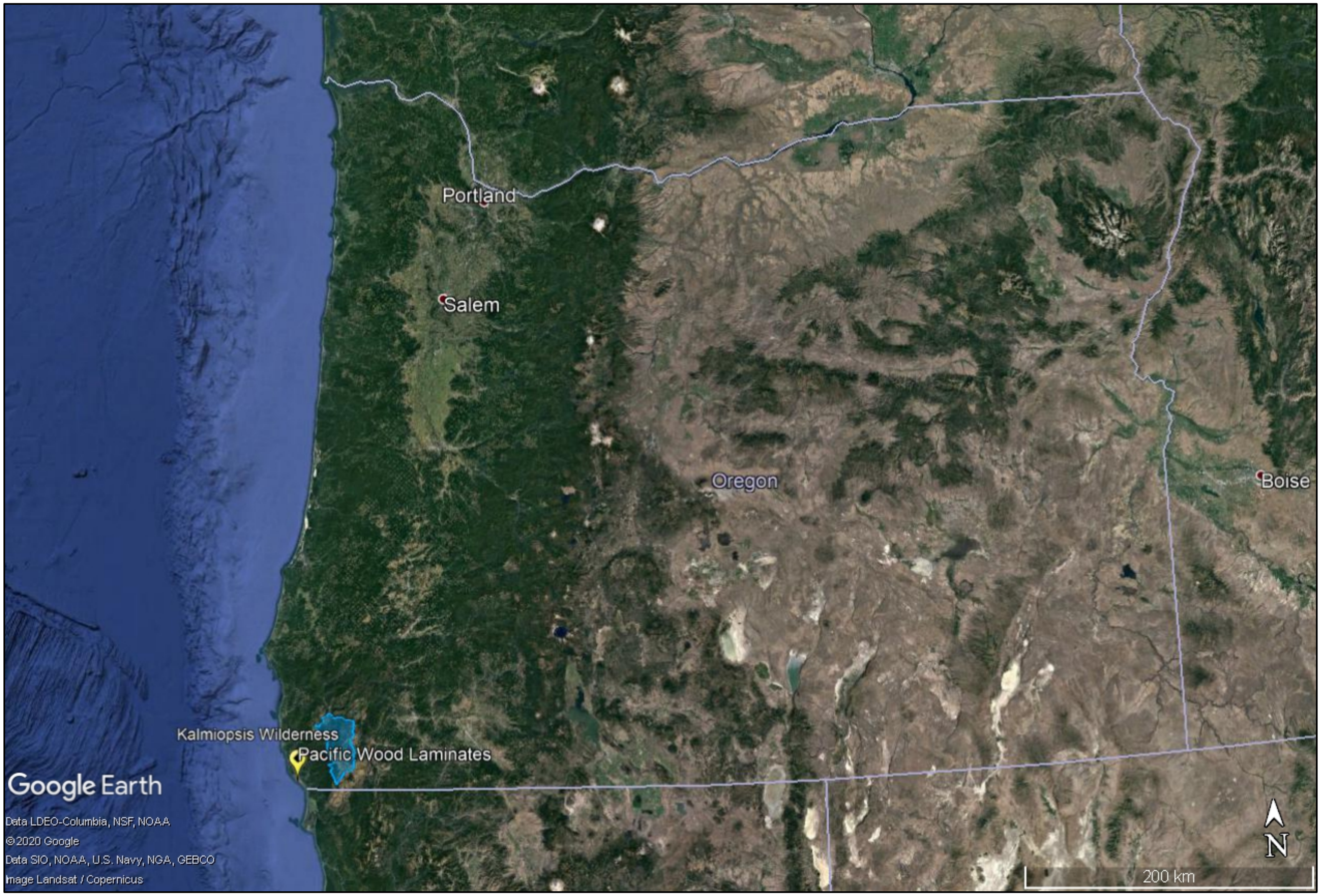
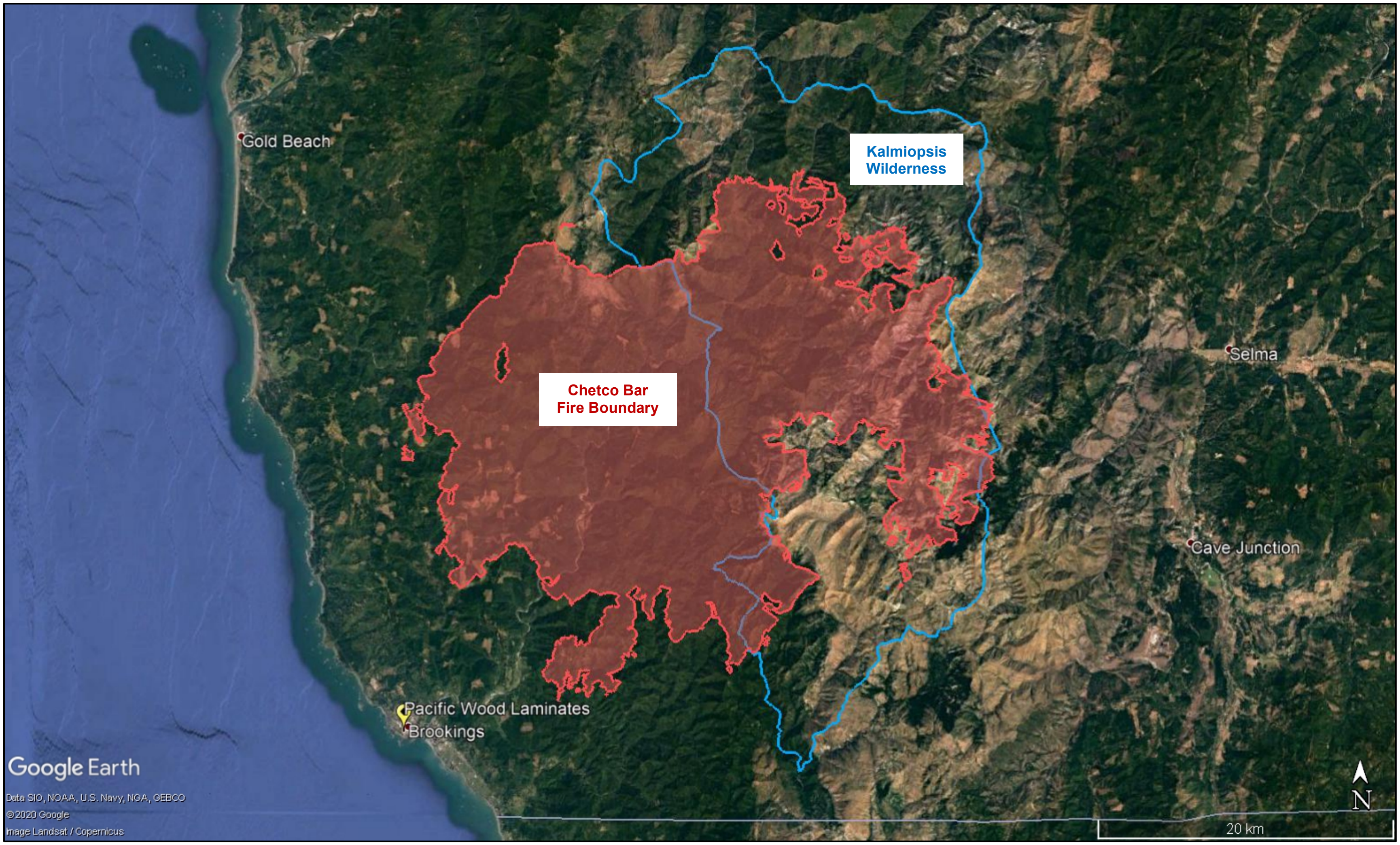


Figure 4-3: PWL Proximity to Kalmiopsis Wilderness Area with Chetco Bar Fire Impact Area



4.3 Historical Facility Upgrades

PWL has taken the initiative to implement multiple upgrades and improvements to the manufacturing plant within the past 20 years. Significant costs have been invested into the facility to increase employee safety, improve efficiency, decrease emissions, and modernize the facility. These facility improvements were completed in good faith by PWL in order to operate a safe and healthy facility for their workers and community. PWL is providing a summary of the projects and upgrades made to the facility to indicate the effort put forth in improving the facility and reducing its impacts. It also demonstrates the experience PWL's management has in developing and understanding the scope of projects within their facility and geographic location.

A summary of the more recent improvements to the facility include:

The modernization and major maintenance of Dryer "C"

- Work performed: 2004 – 2005
- These upgrades included a new veneer feeder, rebuilding of the dryer main fans, new door skins, new door seals, and steam/condensate lines.

The modernization and major maintenance of Dryer "B"

- Work performed: 2008
- Dryer doors were completely rebuilt, as well as the dryer roof, and door seals were replaced.

Major maintenance of the Riley Hogged-Fuel Boiler (PH2) Multi-clone and installation of new Induced Draft Fan (I.D. Fan)

- Work performed: Winter 2012, Spring 2013, and Spring 2015
- This included the complete overhaul and re-tubing of the multiclone.

Replacement of the Plywood Press #4

- Work performed: 2017
- Press #4 was replaced with a modern, SparTek plywood press to improve efficiency and reduce emissions

Installation of a regenerative thermal oxidizer (RTO)

- Work performed: 2018
- The RTO was installed to control emissions from the veneer dryers heated zones and removal of wet scrubbers (WS 1, WS3, WS4).

Construction of new maintenance shop

- Work performed: 2018
- Provides improved enclosure and containment for maintenance activities at facility

Conversion of the RTO to a regenerative catalytic oxidizer (RCO)

- Work performed: 2019

- Upgraded the RTO with the addition of precious metal catalyst to provide better control efficiency to process

Upgrades to the hog fuel handling system

- Work performed: 2018-2019
- Upgrades to the fuel handling system include removing of the Wellons Fuel Silo and the hog fuel return conveyor, the bypass loading station, and the fuel bin out feed. All conveyors are now covered or inside the new fuel house building.

Boiler Fuel Bin Improvements

- Work performed: 2015 to Current.
- Fully enclosed the dry fuel chip bins and installed a negative air system to pull all the particulate into a cyclone and transfer it to another walking floor bin, which feeds fuel to the hogged-fuel boiler.

Boiler Steam Reduction and Energy Conservation Program

- Work performed: 2014 – Present & Ongoing
- This program includes multiple assessments of hogged-fuel boiler operations to ensure the boiler is firing correctly and efficiently. Controls were updated along with operational methodology. A new controls platform was installed along with a tailored PLC Control Logics program. This increased boiler operational efficiencies and operations. Total steam flow from 2019 equivalates to only 75% of the total steam flow produced in 2014. This demonstrates the improvement in boiler operation efficiencies.

Veneer Plant Replacement Project (South Coast Lumber)[14]

- Work performed: 2011 – Present
- Green-end veneer facility replacement to upgrade efficiency and recovery of log to veneer. South Coast Lumber Co. (SCL) is the parent company to PWL. It controls funding and investing at PWL while also providing it with green-end veneer materials. PWL uses the veneer infeed to make plywood and LVL products. The veneer material is the largest cost contributor to making plywood, so the replacement of the facility was a commitment by ownership for continuous improvements at both facilities since it would increase efficiency at both PWL and SCL. Since funding is controlled by the same ownership, it is included in this analysis.

[14] South Coast Lumber Co. is the parent company to PWL. It controls funding and investing at PWL while also providing it with green-end veneer materials. PWL uses the veneer infeed to make plywood and LVL products. The veneer material is the largest cost contributor to making plywood, so the replacement of the facility was a commitment by ownership for continuous improvements at both facilities. Since funding is controlled by the same ownership, it is included in this analysis.

As previously stated, these upgrades and improvements to the facility were completed by PWL to optimize process efficiency and for internal improvements to employee health and safety at the facility. Costs accrued for the projects are included in Table 4-1. The historical investments and improvements to the facility should not be overlooked.

Table 4-1: Historical Facility Improvements and Costs

Improvement	Approx. Cost ($)
Dryer B and C Modernization	3,075,000
PH2 Boiler and Multiclone Upgrades	85,000
Press #4 Replacement	2,960,000
RTO Installation	2,842,000
Conversion to RCO	166,000
New Maintenance Shop	3,825,000
Fuel Handling Upgrades (Includes fuel bin)	4,227,000
PH2 Boiler Efficiency Program	306,600
Veneer Plant Replacement	5,634,000
Total CIP	**$ 23,120,600**

4.4 Facility Emission Sources

Existing emission sources at the PWL facility are characterized in Table 4-2. This represents all emission units regulated by Title V permit 08-0003-TV-01. The associated emission unit ID (EU ID) and pollution control device is also included in the table. Currently, the hogged-fuel boiler is controlled by a multiclone and two wet scrubbers while the veneer dryers are controlled by an RTO/RCO. Additionally, there are four baghouses throughout the facility to control particulate emissions from various conveyance/pneumatic processes.

Table 4-2: PWL Emission Units and Controls

EU ID	Emissions Unit	Pollution Control Device/Practice	Controlled Pollutant
PH2	Hogged-fuel boiler	Multiclone Wet Scrubbers 1&2	$PM/PM_{10}/PM_{2.5}$
MT	Material Transport: Hog fuel truck unloading, hog fuel pile and boiler feed conveyors, truck loading plytrim, sawdust and sander dust	None	N/A
Presses	Plywood Press 1 Plywood Press 2 Plywood Press 3 Plywood Press 4	None	N/A

EU ID	Emissions Unit	Pollution Control Device/Practice	Controlled Pollutant
CON	Pneumatic Conveyors group: Sander dust Cyclone (Baghouse 1) LVL Plytrim Cyclone (Baghouse 2) Hog fuel handling Cyclone (Baghouse 3) Primary plytrim cyclone (Cyclone 1/Baghouse 4) Glue mixer exhaust fan	Baghouse 1 Baghouse 2 Baghouse 3 Baghouse 4	$PM/PM_{10}/PM_{2.5}$
Dryers	Veneer Dryers: Dryer A Dryer B Dryer C	Regenerative Thermal Oxidizer/ Regenerative Catalytic Oxidizer	VOCs
WE	Unpaved Roads	Watering	$PM/PM_{10}/PM_{2.5}$
VOC	Facility VOCs	None	N/A
AI	Aggregate insignificant activities: Radiant propane heater Maintenance shop raw materials and solvents	None	N/A

As stated in Section 1.2, the initial Q/d analysis used to trigger the four-factor analysis requirement was based on the emissions for the entire facility, however the four-factor analysis is focused on individual emission sources. The largest source of SO_2, NOx and PM_{10} emissions at the facility is the hogged-fuel boiler. The boiler accounts for 97% of facility-wide NOx emissions and therefore is being evaluated for NOx through a four-factor analysis. PH2 also accounts for 77% of facility wide SO_2 emissions. However, the PWL facility has minimal SO_2 emissions in total at 4.3 tpy with PH2 contributing only 3.3 tpy. The remaining 23% accounts for 1.0 tpy from aggregate insignificant sources and 0.001 tpy from the RCO. Therefore, no additional sources are evaluated for NOx or SO_2 since PH2 accounts for nearly all corresponding gaseous emissions from PWL.

The primary sources of PM_{10} emissions at PWL are the Riley hogged-fuel Boiler, the veneer dryers, and the plywood presses. They account for 32%, 16%, and 16% of facility-wide emissions, respectively. Additional sources of PM_{10} at the facility include various material transfers and conveyors, sources controlled by baghouses, vehicle travel on unpaved roads, and an aggregation of insignificant sources. None of these additional sources were considered for evaluation by the four-factor analysis because they account for minimal emissions of facility-wide PM_{10} at 0.7 – 9.0 tpy or 0.5% - 7% of total emissions. Additionally, fugitive sources have minimal loft and lack dispersion characteristics to impact a Class I area 23.5 km from the facility.

Therefore, sources with emission contributions substantive enough for consideration of the four-factor analysis evaluation include the hogged fuel boiler, Plywood Presses 1 – 4, and Veneer Dryers A, B, and C. A further analysis and selection of sources is included in the following subsections.

4.4.1 Riley Boiler, PH2 – Selected for Four-Factor Analysis

The hogged-fuel boiler (PH2) at PWL is a Riley stationary grate stoker and water tube boiler. The boiler was initially commissioned by Louisiana-Pacific (LP) in 1969 at the LP mill in Wenatchee, WA. It was moved to Brookings and installed at PWL in 1986. The boiler utilizes hogged fuel as well as sander dust injection to produce steam. It is situated at the facility next to the old, decommissioned Brookings Plywood Dutch-oven boiler 1 (PH1) providing limited space for additional installation or retrofit. As previously stated, boiler PH2 is currently controlled by a multiclone and two wet scrubbers.

The Riley hogged-fuel boiler PH2 was selected as the only source to be evaluated by four-factor analysis because it is the largest contributor of NOx, SO_2, and PM_{10} at the PWL facility. It is evaluated for the additional control of emissions of PM_{10} and NOx. SO_2 is not evaluated because of negligible total SO_2 emissions. Woody biomass fuel is naturally low in sulfur and SO_2 emission controls are typically not used on wood-fired boilers. Any add-on control to further reduce SO_2 emissions would be cost-prohibitive due to the small amount of pollutant that would be controlled. Therefore, the hogged-fuel boiler is evaluated by four factor analysis for emissions of PM_{10} and NOx in Sections 5 and 6.

4.4.2 Plywood Press Exclusion

Plywood presses emit fugitive emissions of VOC and PM_{10} as sheets of wood veneer are pressed together using hot platens; they do not emit NOx or SO_2. Plywood assembly operations are located within a single large building among other sources of emissions. Because plywood presses are co-located with other process units, it is likely that the limited plywood press emissions data that have been collected by the National Council for Air and Stream Improvement (NCASI)[15] also includes fugitive emissions from other different types of process units in the same building. Nevertheless, estimated total plywood press PM_{10} emissions are minimal at ~22 tpy.

Plywood manufacturing facilities are subject to the NESHAP for Plywood and Composite Wood Products (PCWP) in 40 CFR 63, Subpart DDDD. Although veneer dryers are subject to standards, EPA determined that emissions from plywood presses were not amenable to capture and control and did not set any standards for these sources. EPA distinguished emissions control requirements for plywood presses from other reconstituted wood products presses (e.g., particleboard, OSB, and medium density fiberboard) "because of different emissions characteristics and the fact that plywood presses are often manually loaded and unloaded (unlike reconstituted wood product presses that have automated loaders and unloaders)."[16] By virtue of issuing emission control standards for reconstituted wood products presses only, EPA effectively determined that emissions capture and control is practicable for these types of presses,

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[15] NCASI is an association organized to serve the forest products industry as a center of excellence providing unbiased, scientific research and technical information necessary to achieve the industry's environmental and sustainability goals.

[16] EPA, "National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products Manufacturing– Background Information for Final Standards." February 2004.

but not plywood presses. In the September 2019 PCWP NESHAP risk and technology review proposal, EPA did not propose to add standards for plywood presses.

Additionally, the RACT/BACT/LAER Clearinghouse (RBLC) includes no entries for plywood presses with add-on emissions controls. EPA's database of emission sources that was developed for the risk and technology review of the PCWP NESHAP indicates that no plywood presses at HAP major sources are enclosed or controlled. We are aware of one minor source (Freres Lumber) that installed a partial enclosure and a biofilter to control formaldehyde and methanol emissions to reduce HAP emissions below major source levels and avoid coverage under the PCWP NESHAP, but they are the only facility that has any emissions controls on a plywood press, and the biofilter is not in place to control PM_{10} emissions.

Plywood presses are fugitive sources whose emissions pass through the building roof vents above the presses. Existing vents in the vicinity of these process units are not intended to quantitatively capture and exhaust gaseous emissions specifically from the plywood presses; rather, they are strategically placed to exhaust emissions from the building. When the process and building ventilation layouts were designed, the possibility of emissions capture or testing was not contemplated.

Plywood presses are not enclosed because they need to be accessed by employees. Plywood manufacturing facilities typically have one layup line that feeds multiple presses. On the layup line, layers of dried veneer are laid down in alternating directions with resin applied between each layer. At the end of the line, the layered mat is trimmed, stacked, and moved to the press infeed area for each press. This configuration requires more operating space and manual input than other wood products manufacturing processes. Plywood presses are batch processes and loading the press is manually assisted (the press charger is manually loaded). Operators must be able to observe press operation to check that the press is properly loaded. Pressed plywood is removed from the area using a forklift. Adding an enclosure to capture emissions is not feasible because it would disrupt operation of the press (both infeed and outfeed), inhibit maintenance activities, and create unsafe working conditions for employees (isolation, heat, emissions, and exposure).

There are no technically feasible controls to reduce plywood press PM_{10} emissions due to the infeasibility and unsafe risk of control and capture. Therefore, the four-factor analysis is not evaluated.

4.4.3 Veneer Dryer Exclusion

Veneer dryers A, B, and C are used to dry thin sheets of wood (veneer) that will be used to make plywood. The first step in producing plywood is to dry the inner veneer plies, or the core of a panel product, to drive moisture out of the material. A suitable moisture content is required in the veneer to provide quality inner plies and to allow for the proper bonding of plywood. Drying veneer is critical to producing a quality plywood product. The veneer dryers at PWL emit PM_{10} and VOCs while drying material. They are also a minimal emitter of NOx (1.75 tpy) and SO_2 (0.001 tpy). The veneer dryers account for approximately 22 tpy of PM_{10} emissions at PWL.

Currently, the veneer dryers are controlled by RTO/RCO to reduce emissions of VOCs and hazardous air pollutants (HAPs). Again, PWL is subject to 40 CFR 63, Subpart DDDD for PCWP. Use of the RTO/RCO maintains compliance with the applicable Maximum Achievable Control Technology (MACT) standards for the veneer dryers. RTO/RCOs are not mandated as a specific requirement for the facility under Subpart DDDD, however PWL installed the Best Available Control Technology (BACT) to guarantee the greatest level of control. RBLC includes entries for veneer dryers controlled by RTO/RCO but includes no entries with add-on emissions controls for PM_{10}. Additionally, RCO is considered Best Available Control Technology for Toxics (TBACT) for controlling toxic air pollutants (TAPs) regulated by the Cleaner Air Oregon program. This provides more indication of PWL's commitment to emissions reductions within other regulatory programs.

The proper operation of the veneer dryers is critical to the quality of material produced at PWL. Add-on controls beyond the RTO/RCO could interfere with the production of the veneer dryers, compromise product quality, or compromise the efficiency of the RTO/RCO. Therefore, no additional control options are evaluated for the veneer dryers. No other facilities have proven the feasibility or necessity in controlling PM_{10} emissions from veneer dryers controlled by RTO/RCO per RBLC and the dryers are a smaller source of PM_{10} at the facility. Therefore, a four-factor analysis is not evaluated.

5.0 FOUR-FACTOR ANALYSIS FOR SO_2 AND NO_X

Evaluation of available control technologies requires an analysis of the cost effectiveness of the emissions control application. Cost effectiveness relies on a comparison of the current uncontrolled NOx and SO_2 emissions to NOx and SO_2 emissions, individually controlled by respective technologies.

The following sections present the analysis for the PWL Brookings facility using the direction of the EPA Draft Guidance [9] and WRAP four-factor analysis guidance [10]. The initial step in the four-factor analysis was to identify possible additional control options for this source. As discussed in Section 4.4.1 above, the four-factor analysis focused on controls for the PWL hogged fuel boiler.

5.1 Available SO_2 Control Technologies

SO_2 is formed during combustion due to the oxidation of sulfur in the fuel. Woody biomass fuel is naturally low in sulfur and SO_2 emission controls are typically not used on wood-fired boilers.

The Oregon annual air contaminant emissions reports rely on an SO_2 emission factor provided in the PWL air quality permit of 0.015 lb/klb. The current actual emissions are calculated based on the average boiler steam production rate for reporting years 2016 – 2019. The average boiler steam production rate was 295,671 klb/yr and current actual SO_2 emissions are estimated as follows:

0.015 lb/klb * 295,671 klb/yr ÷ 2000 lb/ton = 2.2 tpy

The hogged fuel boiler accounts for 77% of SO_2 emissions from the facility with aggregate insignificant activities accounting for the other 23%.

Any add-on control to further reduce SO_2 emissions would be cost-prohibitive due to the small amount of pollutant emitted so a four-factor analysis was not assessed for SO_2 emissions.

5.2 Available NO_x Control Technologies

NOx is formed during the combustion of woody biomass in the hogged fuel boiler. NOx comes from two sources in combustion, fuel NOx and thermal NOx. Fuel NOx forms due to oxidation of nitrogen contained in the biomass fuel and thermal NOx forms from the thermal fixation of atmospheric nitrogen and oxygen in the combustion air. NOx emissions from a boiler can be controlled using combustion modifications that reduce thermal NOx formation, or by add-on control devices to remove NOx from the exhaust stream after it is formed. Combinations of combustion controls and add-on controls may also be used to reduce NOx. This analysis will consider the following NOx control technologies:

- Combustion modification
- Selective catalytic reduction (SCR)

- Regenerative selective catalytic reduction (RSCR)
- Non-selective catalytic reduction (SNCR)

5.2.1 Combustion Modification

As previously mentioned, the hogged fuel boiler at PWL is a Riley stationary grate stoker and water tube boiler. It was initially commissioned in 1969 and installed at PWL in 1986 with limited space or technical feasibility for retrofit. Combustion controls, such as flue gas recirculation, staged combustion, low NOx burners, and fuel staging are either not compatible with this boiler or do not have high NOx control rates. Hogged fuel also contains some fuel-bound nitrogen that readily converts to NOx, which is not reduced by combustion controls. This fuel-bound nitrogen further reduces the assumed NOx control of the various combustion modifications. Additionally, the boiler utilizes hogged fuel as well as sander dust injection. Control options, such as low NOx burners, are likely not available for the co-firing of sander dust fuel because of likelihood of fouling. Converting the boiler to natural gas is also infeasible because natural gas is not available to the southern coast area. Conversion to propane would not be cost effective.

5.2.2 Selective Catalytic Reduction

SCR is a post-combustion gas treatment technique for reduction of nitric oxide (NO) and nitrogen dioxide (NO_2) to molecular nitrogen, water, and oxygen. Ammonia (NH_3) or urea is used as the reducing agent and is injected into the flue gas upstream of a catalyst bed. Urea is converted to ammonia after injection into the hot flue gas. NOx and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate which subsequently decomposes to elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NOx decomposition reaction. Technical factors that impact the effectiveness of SCR include inlet NOx concentrations, catalyst reactor design, operating temperatures and stability, fuel type and sulfur content, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning [11].

SCR is not widely used with wood fired combustion units because of the amount of particulate that is generated by the combustion of wood. When the combustion source is a biomass-fired boiler, the SCR must be placed downstream of the particulate control equipment for proper operation. However, the particulate – if not removed completely – can cause plugging in the catalyst and reduce the surface area of the catalyst available for reaction. The presence of alkali metals commonly found in wood, such as sodium and potassium, will irreversibly poison catalysts. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic. In order to prevent the plugging, binding, and/or poisoning of the SCR catalyst, it is necessary to first remove particulate from the exhaust gases. However, it is not considered technically feasible to place a SCR unit upstream of the particulate control device in a wood-fired boiler or burner application because of the SCR flue gas temperature requirements.

SCR control technology works best for flue gas temperatures between 575°F and 750°F and is typically installed upstream of any particulate control equipment where the temperature is high enough to support the process. At this point in the exhaust system, the flue gas temperature is lower than required for the SCR to operate effectively. Source tests of the hogged fuel boiler show an average stack exit temperature of approximately 490 - 500°F.

SCR has not been required on small- and medium-sized biomass-fired boilers according to a search of the most recent ten-year period in EPA's RBLC database. For the reasons stated in this section, PWL considers this alternative technically infeasible, and SCR is eliminated from any further consideration as a feasible control technology.

5.2.3 Regenerative Selective Catalytic Reduction

RSCR is a commercially available add-on control technology by Babcock Power Inc. that combines the technology of a regenerative thermal oxidizer device and SCR. Ammonia is injected upstream of the catalyst just as with a traditional SCR unit, and the reactions between ammonia and NO are the same. The control equipment is intended to be placed downstream of emission control systems where the exhaust gas is clean, but the temperature is below the optimal temperature range for catalytic reduction of NOx. Therefore, the RSCR unit has a front-end preheating section that reheats the exhaust stream with a regenerative thermal device. The exhaust is heated to a temperature in the range optimal for catalytic reduction (600°F to 800°F) prior to entering an SCR unit.

The RSCR units were being heavily marketed in 2011 but concerns across the air pollution control industry relating to the catalyst performance, unit cost, and thermal efficiency inhibited widespread adoption. RSCR vendors have not guaranteed catalyst life beyond three years due to the potential for poisoning and blinding associated with the combustion products of wood fuels. It is known in the wood products industry that catalyst media becomes poisoned, plugged, or quickly destroyed in particulate laden biomass direct fired applications.

No BACT determinations for RSCR units have been made in the past 10 years for control of NOx emissions from units combusting wood, wood products, or biomass. Therefore, RSCR unit is not technically feasible for wood combustion units and is eliminated from any further consideration as a feasible control technology

5.2.4 Selective Non-catalytic Reduction

SNCR drives the noncatalytic decomposition of NOx in the combustion gases to nitrogen and water using a reducing agent (e.g., ammonia or urea). The reactions take place at much higher temperatures than in an SCR, typically between 1,650°F and 1,800°F, because a catalyst is not used to drive the reaction. The SNCR reaction can take place upstream of the particulate control equipment and supplemental fuel is not required. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NOx emissions may result [12].

Removal efficiencies of NOx vary for SNCR, depending on inlet NOx concentrations, fluctuating flue gas temperatures, residence time, amount, and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and the presence of interfering chemical substances in the gas stream. The estimated control efficiency for SNCR retrofitted onto an existing hogged fuel-fired boiler is 30%-50%.

SNCR technology is a feasible emissions control for wood-fired boilers and will be evaluated in this four-factor analysis. This potential feasibility is reflected in a recently permitted biomass-fired boiler of similar size that was equipped with SNCR to meet the BACT control requirements (RBLC ID SC-0149). The following four-factor analysis examines the environmental, energy and economic impacts of an SNCR installation on the hogged fuel boiler.

5.3 Current Actual NOx Emissions and Post-control NOx Emissions

Current NOx Emissions

The hogged fuel boiler is not currently equipped with NOx control, nor are there any permit limits on NOx emissions from the boiler. For setting the baseline for this analysis, the results of a June 11, 2019 source test were used for the inlet NOx rate. The average result from the tests is 0.2458 lb NOx per MMBtu. The higher heating value of the fuel is 17,480,000 btu per bone dry ton (BDT) based on Title V permit 08-0003-TV-01. Estimated actual annual fuel consumption is calculated at 27,883 BDT per year based on a four-year average of fuel input from 2016 – 2019. These values allow for the calculation of annual emissions as follows:

0.2458 lb NOx/MMBtu * 17.48 MMbtu/BDT * 27,883 BDT/year * 1 ton/2000 lb = 59.9 tpy

PWL operates 8,064 hours per year as stated in 08-0003-TV-01. That equates to 14.9 lb/hr of NOx emissions.

SNCR Controlled NOx Emissions

Equation 1.17 in the EPA Control Cost Manual for SNCR [12] is a means for estimating the Normalized Stoichiometric Ratio (NSR). The NSR defines the amount of reducing reagent (ammonia or urea) needed to achieve a targeted NO_x reduction; since more than the theoretical stochiometric amount of ammonia or urea is required to reduce a given amount of NOx, the NSR ranges between 0.5 and 3. Figure 1.7 in the Control Cost Manual shows the effect of the NSR on NOx reduction. Just above the figure, the Manual states, "Increasing the quantity of reagent does not significantly increase the NOx reduction for NSR values over 2.0." Additionally, increasing the amount of reducing reagent added to the system results in increasing amounts of ammonia slip which is an undesirable by-product that is discussed in Section 5.6.

Based on Equation 1.17 and an upper bound of 2.0 for NSR, the estimated achievable NO_x reduction in the boiler is 41%. This estimated NOx reduction is reasonable, and possibly even optimistic, given the relatively low inlet NOx emissions from the boiler. The controlled NOx emission rate is calculated as follows:

0.2458 lb/MMBtu * (1 - 0.41) = 0.1450 lb/MMBtu

Again, this reduction is based on the upper bound NSR to prevent ammonia slip based on Equation 1.17. This would result in approximately 35.3 tpy and 8.8 lb/hr of NOx emissions.

5.4 Factor 1: Cost of Compliance

The cost of compliance analysis was based on a spreadsheet developed by EPA to implement the June 2019 update of the SNCR chapter of the EPA Control Cost Manual [13]. Additional cost information is provided by the SNCR vendor (Wellons), KH2A Engineering, Arctic Engineering, and PWL. A printout of the completed spreadsheet is included in Appendix B along with supporting information. The vendor quote used in the analysis is included in Appendix D.

The SNCR cost estimate spreadsheet is designed for use with coal-, oil-, and natural gas-fired boilers. Bison has modified the spreadsheet for use with PWL's hogged fuel boiler by using wood fuel characteristics instead of the fuel characteristics included in the spreadsheet. The higher heating value (HHV) of the hog fuel was adjusted to reflect the average moisture content of the fuel as listed in 08-0003-TV-01. Additionally, the four-year average from 2016 – 2019 was used to estimate actual annual fuel consumption in BDT per year. These values are previously discussed in Section 5.3.

5.4.1 SNCR Data Inputs

The combustion unit is an existing industrial boiler so the addition of an SNCR is classified as a retrofit installation. A retrofit factor of 1 was used to indicate that it would be expected to be a project of average retrofit difficulty although the modification is expected to be more difficult than average (EPA provides little guidance with respect to the retrofit factor). The complications in the modification/retrofit are instead addressed directly by PWL and accounted for in the cost evaluation spreadsheet and this section. Therefore, other capital outlay based on boiler modifications, civil engineering, control monitoring, and earthquake design are accounted as individual costs rather than through the use of the retrofit factor.

The fuel type box in the cost spreadsheet is blank because no default fuel information was used. Instead, a net plant heat input rate (NPHR) was calculated based on wood biomass. The boiler heat input rate is 86 MMBtu/hr and the HHV of the hogged fuel is 17,480,000 Btu per BDT based on 08-0003-TV-01. Actual annual fuel consumption is estimated to be 27,883 BDT/yr for the boiler based on a four-year average (2016 – 2019). The NPHR was calculated at 17.5 million Btu per megawatt-hour (MMBtu/MWh) based on the conversion of 1.0 BDT/MW [17]. The NPHR was calculated as follows:

17,480,000 Btu/BDT * 1 BDT/MW * 1 MMBtu/10^6 Btu = 17.5 MMBtu/MW

Inlet NOx emissions to the SNCR are 0.2458 lb/MMBtu based on the average NOx emissions measured at the two wet scrubbers during a June 11, 2019 stack test. A removal efficiency of 41% is assumed as explained above due to the NSR. A corresponding outlet NOx emission rate from the SNCR equates to 0.145 lb/MMBtu.

An SNCR system using urea injection was selected based on the Wellons quote. The default reagent values in the EPA spreadsheet for urea were utilized as no specific values were provided from the vendor.

Cost values are based on the 2019 Chemical Engineering Plant Cost Index (CEPCI) value of 607.5, based on the annual average [14].

The currently published prime rate of 3.25% was used as the annual interest rate.[17] PWL operates under the fiscal and managerial structure of South Coast Lumber (SCL). Financing of projects is procured through SCL at their chosen interest rate and financial discretion. PWL notes that the interest rate for any project financing would likely be greater than the current bank prime rate and is not necessarily reflected accurately in the analysis. However, PWL also acknowledges the use of the prime rate to standardize all Round 2 four-factor analyses in Oregon. So, this analysis utilizes the bank prime rate at the request of ODEQ guidance.

An estimated equipment life of 20-years is utilized for the SNCR per the EPA Control Cost Manual. PWL acknowledges that ODEQ requests a 30-year expected life, however the EPA Control Cost Manual applies a 20-year equipment life to retrofit SNCR which appropriately supports this analysis. PWL believes the actual equipment life will likely be in the 10 to 12-year range due to the local climate. The coastal location of the PWL facility in southwest Oregon provides exposure to heavy rainfall, ocean fog, and sea spray. Existing equipment at the facility is painted annually to prevent corrosion and protect from rust and degradation. Fuel systems and chip bins are often re-skinned to prevent degradation. Figure 5-1 provides an example of equipment corrosion from extreme weather conditions. The photograph shows support steel that had been installed less than 30-years prior. Therefore, the 20-year expected life is utilized in the analysis. A cost effectiveness accounting for 30-years is also included as a footnote to the section.

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[17] Bank prime loan interest rate of 3.25% as of June 8, 2020: https://www.federalreserve.gov/releases/h15/

Figure 5-1: Steel Degradation at PWL Due to Exposure

The fuel cost for the hog fuel was estimated to be $2.00/MMBtu based on an average 2016 price of $32 per bone-dry ton (BDT) delivered [15] (corrected to 2019 dollars using the CEPCI) and a fuel HHV of 8,740 Btu/lb on a dry basis. Ash disposal cost for the additional fuel burned to drive the SNCR reaction was not included. The spreadsheet default costs for reagent, water and electricity were used in the analysis. The spreadsheet also accounts for 336 days of operation per year as stated in 08-0003-TV-01.

5.4.2 Capital Cost Analysis

PWL consulted Wellons to provide a cost quote for the installation of a SNCR control system to the hogged fuel boiler. It is included in Appendix D. The quote provides a limited capital cost of $800,000 that includes a urea storage tank, system piping, compressed air system, skid, injection nozzles, control panel, software, and mechanical installation. However, it does not include the cost associated with modifying the boiler, site work to accommodate additional equipment, upgrades to the boiler control system, and a continuous emissions monitor system (CEMs).

PWL consulted KH2A engineering and Arctic Engineering to develop additional costs pertaining to the engineering, site preparation, permitting, and installation of the control system. Additionally, PWL has extensive knowledge and familiarity in developing projects at the facility as indicated by the list of recent upgrades and modifications detailed in Section 4.3.

The calculation methodology for SNCR in the EPA Air Pollution Control Cost Manual is somewhat different than the general Control Cost Manual methodology because it does not estimate equipment costs and installation costs separately. Instead, the purchased equipment cost, the direct installation cost, and the indirect installation cost are estimated together.

Therefore, the TCI includes the direct and indirect costs associated with purchasing and installing SNCR equipment. Costs include SNCR equipment, auxiliary equipment, direct and indirect installation, additional costs due to installation, buildings and site preparation, offsite facilities, land, and working capital. The EPA Control Cost Manual spreadsheet aids in calculating the capital cost and balance of plant (BOP) cost. Those costs are summed together and a factor of 1.3 is applied to estimate engineering and construction management costs, installation, labor adjustment for the SNCR, and contractor profit and fees. The PWL analysis expands on the Control Cost Manual methodology and provides specific costs for engineering, construction, and installation instead of utilizing the factor of 1.3. Table 5-1 provides the costs accounting for the TCI of an SNCR system installation to the hogged-fuel boiler. The Wellons quote provides the capital cost of the project. The BOP costs are evaluated using the Control Cost Manual methodology. Instead of the 1.3 factor, the additional costs associated with engineering design, construction, and boiler/facility modification are provided individually and further discussed below.

Table 5-1: SNCR Total Capital Investment Analysis

Expenditure	**Cost**
Capital Cost (Wellons Quote)	$ 800,000
Balance of Plant Cost	$ 523,656
Civil and Structural Engineering	$ 600,000
Site Work	$ 1,800,000
Boiler Modification	$ 3,150,000
CEMs Installation	$ 250,000

The vendor-provided quote from Wellons comprises of the capital costs associated with the project. As previously stated, this accounts for the SNCR and associated equipment. It does not include the cost associated with modifying the boiler, site work to accommodate additional equipment, upgrades to the boiler control system, and a CEMs.

BOP costs are calculated using the methodology within the EPA Control Cost Manual spreadsheet for SNCR. It represents costs categorized within the Control Cost Manual such as auxiliary power modifications, electrical upgrades, and site upgrades typical of the installation of an SNCR unit.

Civil engineering, structural engineering, and site work will be extensive for this hypothetical project due to the current facility layout and the geographical location of the PWL facility. These considerations were evaluated by KH2A and PWL. A lack of available space near the boiler will require an overhaul of the area to accommodate the SNCR system. The current boiler building will require modification and subsequent retrofit to meet current code. Modification to the layout would require the removal of PWL's old

Dutch-oven boiler (PH1) to accommodate the SNCR control unit and auxiliary equipment. Additional upgrades would be required to the fire pump room and the fire suppression system. A fire suppression system is currently buried underground on the west-side of the boiler. A section of that system would likely need to be relocated to accommodate the SNCR system and provide adequate fire suppression.

Additionally, any work to the existing foundation or any new construction (Urea storage tank area and SNCR skid) would require extensive structural design and geotechnical engineering because of the facility's location within the Cascadia subduction zone/fault line. Over-engineering practices are required for new construction due to the location within the fault zone and the facility's proximity to the ocean. Therefore, building costs, concrete, site work, and construction will require substantially more design and material than a general project.

As previously stated, the PWL facility is within 0.2 km of the Pacific Ocean coastline. Applicable seismic and wind loads for this site are high. The seismicity of Brookings is the highest in the entire State of Oregon. Design accelerations specified by the Oregon Structural Specialty Code require 200% of "g" be used for lateral design. The design parameter "g" is the force of gravity downwards, so 200% g acting in the lateral direction is very high seismicity. Design wind speeds for Brookings are also high and vary from 125 to 145 mph depending on the structure Risk Category. Very high seismic and wind loads result in heavier, stronger, and more costly structures and foundations.

The current facility layout and soil structure also provides difficulty in design and construction. The site soil conditions, in and around an old mill pond was filled with material of dubious quality and are prone to liquefaction during significant seismic events. Liquefaction causes the soil grains to rearrange themselves in a fluid fashion. Impacts of liquefaction include soil settlement, loss of soil bearing strength, lateral spreading, and amplified foundation vibration. Mitigation for the liquefaction hazard regarding foundation design includes Code-driven deep foundations (piles or piers deriving their soil bearing strength from embedment in competent soil layers beginning about 20 feet below ground surface). Otherwise, the liquefiable layers would need to be removed and replaced with stronger engineered fill materials. Both methods are costly to execute. Recent projects in this area used conventional footings founded upon the deep competent soil layers. Exact extents of the susceptible soils are not precisely known, adding to the potential uncertainty in design and costs.

Modification to the boiler will also provide challenges given the current configuration at the facility. The installation would require R-stamp tube work as well as sign off for insurance purposes. The boiler would also likely require replacement of a newly sized F.D. and/or I.D. fan as well as a firebox to accommodate effective urea injection and boiler operation. Additional modifications will need to be made to the boiler to ensure proper operation with the SNCR system.

Lastly, the addition of an SNCR would likely require the installation of a CEMs to determine the appropriate injection rate and placement of urea. This helps aid in the overall maintenance of the boiler by preventing degradation from the urea injection and prevents ammonia slip formation.

Collectively these costs equate to the TCI for the installation of SNCR to the hogged-fuel boiler and were further evaluated for cost effectiveness.

5.4.3 Cost Effectiveness Calculation Results

The cost calculation indicates that the addition of SNCR to the hogged fuel boiler would have a cost effectiveness of $30,216 per ton of NOx removed, in 2019 dollars. This value represents the cost of installing and operating SNCR add-on NOx control technology and CEMs in the Riley hogged-fuel boiler. If the boiler were retrofitted with SNCR, approximately 22.6 tons per year of NOx emissions would be eliminated.

Table 5-2: Hogged Fuel Boiler Cost Effectiveness Analysis – NO_x

Control Technology	% Reduction	Emissions (tons/year)	Emissions Reduction (tons/year)
No NOx Control (Base Case)	Base Case	59.9	Base Case
Combustion Modification	Not feasible due to boiler age and design.		
SCR/RSCR	Not feasible due to boiler exhaust characteristics.		
Selective Non-catalytic Reduction	41.0%	35.3	22.6
SNCR Cost Parameters			
Boiler Fuel Consumption Rate	27,883 bone dry tons (BDT) per year		
Fuel Higher Heating Value	17,480,000 Btu per BDT		
Total Capital Investment	$7.1 million		
Total indirect annual costs, including capital recovery	$493,313		
Total direct annual O&M Costs	$160,182		
Total Annual Capital Recovery and O&M Costs	$653,495		
Cost per ton PM10 Removed[18]	$653,495 ÷ 22.6 tpy = $28,912/ton		

5.5 Factor 2: Time Necessary for Compliance

For SNCR, EPA states in its Control Cost Manual, "Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the boiler design and operating conditions." [12] PWL estimates that SNCR retrofitting would require approximately 24 - 60 months for design, permitting, financing, etc. through commissioning. This downtime would account for the site preparation and

[18] Cost per ton in table 5-2 is based on a 20-year expected equipment life. SNCR installation with a 30-year expected life equates to $23,838 per ton NOx removed.

construction surrounding earthquake requirements and soil challenges. Removal of equipment would be required as well as the re-construction and design of existing equipment. Additionally, retrofitting the Riley hogged-fuel boiler with SNCR would require shutting down the boiler for extended periods of time for site renovation and boiler retrofit. PWL does not have an alternative or replacement boiler so production would be stopped indefinitely. Additional profits would be lost, and employees furloughed due to the retrofitting process.

5.6 Factor 3: Energy and Environmental Impacts of Compliance

SNCR presents several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. Ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. Ammonium sulfate is the leading contributor to visibility impairment (anthropogenic sources) in the Kalmiopsis Wilderness, as discussed in Sections 2.1 and 3.4. Additionally, ammonia slip would potentially provide nuisance odor and visibility impairment locally in Brookings.

An SNCR system would have a small energy penalty on the overall operation cost of the boiler. Costs for this energy expenditure are included in the discussion of Factor 1, cost of compliance.

PWL is located within approximately 0.2 km of the Pacific Ocean coastline. On-site storage of Urea poses a pollutant discharge risk to the surrounding water table and the coastal ecosystem via contaminated runoff or spill.

5.7 Factor 4: Remaining Useful Life

The Riley hogged-fuel boiler was installed at PWL in 1986 and was originally commissioned in 1969. The boiler has been adjusted and tuned to efficiently operate with the PWL fuel source of coastal grown logs, recovery wood fiber from salvage logs, and sustained yield timber from the Company’s timber lands. Most importantly, the boiler effectively processes residuals from fee timber lands. The remaining useful life of the boiler is considered to be at least the entire duration of the capital recovery period of the cost analysis.

5.8 Technical Feasibility Discussion

Potential difficulties surrounding current facility operations and fuel use could prevent the technical feasibility of retrofitting the Riley hogged-fuel boiler for application of SNCR. These engineering and operational risks are difficult to estimate therefore PWL considered SNCR a potentially feasible option for the four-factor analysis. However, these concerns would only be determined through the retrofit, re-design, and modification process of the boiler which could lead to major operational pitfalls if discovered during the reconstruction process. They are addressed in the section for further consideration towards SNCR application.

Firstly, the hogged fuel boiler will require extensive retrofit as described in Section 5.4.2. This will likely include a new F.D. or I.D. fan and firebox to accommodate for boiler operational adjustment, urea injection, and residence time. However, the difficulties are not solely limited to the mechanics of the boiler. Difficulties also exist surrounding fuel usage requirements for PWL. The boiler fires on both hogged fuel infeed and sander dust injection. SNCR relies on the injection of urea in the combustion chamber which may have negative consequences when combined with the particulate loading from sander dust injection. The facility's inability to utilize sander dust as fuel would then create issues surrounding waste disposal and winter operational feasibility.

The combustion of sander dust helps prevent waste-product build up at the facility, so it is injected up to 8 or 10 hours a day during boiler operation. The sander dust product builds up and must be burned at the facility because there is no way to landfill the material economically. Without sander dust injection, PWL would be required to haul the material by truck to Medford, OR for disposal, if accepted at the landfill. Additionally, sander dust injection is also essential for operating the boiler during the winter season in Brookings. The hogged fuel can achieve a 50-60% moisture content due to heavy rainfall in the winter. The sander dust injection is necessary to achieve sufficient heat content to dry the hogged fuel infeed and provide boiler combustion. Additional moisture in the winter via urea injection would create a further saturated fuel feed in the winter inhibiting boiler operation. Even more so, SNCR interference or incompatibility with sander dust injection would potentially prevent winter operation of the boiler and greatly increase operational costs at PWL if disposal by landfill were required in place of combustion.

Additionally, proper application of SNCR requires an optimal injection temperature window and residence time for proper control. The location of the desired temperature window will likely change with operational fluctuations and type of fuel feed. PWL processes various species of wood throughout the year and the type of fuel fed into the boiler fluctuates monthly and seasonally. This makes it difficult to determine an accurate and consistent temperature window in the boiler for proper injection. Ammonia slip could then be a recurring problem associated with the application of the SNCR. The existing wet scrubbers would help collect ammonia slip from the effluent stream however it would then prevent PWL from being able to appropriately process the wet scrubber bleed-down water. Currently, PWL is permitted to discharge wet scrubber bleed-down water under a City of Brookings sewer discharge permit. The addition of ammonia would not meet discharge requirements. Thus, PWL would need to determine a method for tracking ammonia concentration from the wet scrubber discharge and determine an alternative method of disposal if necessary.

Due to the above stated risks, PWL believes the installation of SNCR would presumably require the replacement of the wet scrubbers with a dry electrostatic precipitator (ESP) as well. A review of the EPA RBLC database from 2000 – 2020 further supports this presumption. A review of biomass-fired boilers under process type 12.120 (<100 MMBtu/hr) and 13.120 (100 – 250 MMbtu/hr) indicates that only boilers equipped with

SNCR employ ESP for particulate control. No listed boilers utilize wet scrubbers in conjunction with SNCR. If this were the case at PWL then the total capital investment for the removal of the wet scrubbers and the installation and operation of an ESP would need to be included in the cost of SNCR control. An ESP cost analysis is included in Section 6. Additionally, the wet scrubbers currently utilize the wastewater from the dryers. So, if the wet scrubbers were removed to place an ESP and SNCR then PWL would need to construct more water storage and processing system/infrastructure as well.

6.0 FOUR-FACTOR ANALYSIS FOR HOGGED-FUEL BOILER: PM_{10} EMISSIONS

Evaluation of available control technologies requires an analysis of the cost effectiveness of the emissions control application. Cost effectiveness relies on a comparison of the current PM_{10} emissions as controlled by the existing wet scrubbers and the PM_{10} emissions as controlled by an alternative technology.

The hogged fuel boiler, PH2, is currently equipped with a multiclone to control the bulk of the particulate matter emissions from the boiler. The multiclone is the primary PM emissions control device and is followed two wet scrubbers as secondary control devices. The exhaust from the multiclone split between the two wet scrubbers.

This evaluation will examine the cost effectiveness of replacing the wet scrubbers with a more efficient secondary particulate control device. This provides an "effective" emissions reduction by comparing the currently controlled emission rates from the wet scrubbers to any further reduced emission rate from improved control.

The current actual emissions from the wood-fired boiler are the emissions as controlled by the multiclone and wet scrubber, as discussed in Section 6.2 below.

6.1 Available PM_{10} Control Technologies

A variety of particulate control technologies are available for removing particulate matter from the wood-fired boiler exhaust. The available types of control devices are listed below in order from least to most efficient.

- Mechanical collectors (cyclone or multiclones)
- Wet scrubber
- Fabric filter baghouse
- Electrostatic precipitator (ESP)

6.1.1 Mechanical Collectors

Wet scrubbers, baghouses and ESPs are the particulate control devices most frequently installed downstream of a mechanical collector system. The mechanical collector removes the bulk of the large particulate and reduces the loading on the secondary control equipment. The PWL hogged fuel boiler is already equipped with a multiclone upstream of the existing wet scrubbers. A multiclone is an array of cyclones used to mechanically separate particulate matter emissions from the boiler flue gas. The multiclone removes cinders and entrained fuel particles as well as the much smaller PM_{10} emissions.

This analysis evaluates the cost and feasibility of changing the secondary PM_{10} emissions control equipment downstream of the multiclone to improve the collection efficiency. The multiclone would not be removed or replaced.

6.1.2 Wet Scrubbers

In wet scrubbing processes, liquid or solid particles are removed from a gas stream by transferring them to a liquid. The liquid most commonly used is water. A wet scrubber's particulate collection efficiency is directly related to the amount of energy expended in contacting the gas stream with the scrubber liquid. Most wet scrubbing systems operate with particulate collection efficiencies over 95 percent.[19]

The two wet scrubbers were installed in 1987 to control emissions from boiler PH2. Each scrubber receives approximately 50% of the exit gas flow from the multiclone. They are considered to achieve a 95% control efficiency as stated in 08-0003-TV-01.

PWL has performed emissions testing on the wet scrubber outlets which is used as input data in the four-factor analysis.

6.1.3 Fabric Filter Baghouses

Fabric filter baghouses are not commonly installed on wood-fired boilers because of the fire risk. The filter bags can become caked with a layer of wood ash containing unburned carbon. If a spark escaped the multi-cyclones, it would very easily start a fire in the baghouse. Use of a baghouse on a wood-fired boiler would require use of an abort stack to be triggered whenever a spark was detected, or the spark detector equipment was being cleaned. Because of the fire risk and the need for a baghouse bypass system, use of a fabric filter baghouse will not be considered further for this analysis. It is considered unsafe and therefore infeasible.

6.1.4 Electrostatic Precipitator (ESP)

ESPs are commonly used as a secondary particulate control technology for wood-fired boilers. Dry ESPs are common and do not create a contaminated water stream. They are generally much less susceptible to fire than fabric filter baghouses.

ESPs control emissions of particulate matter by charging the particles as they pass through an electric corona discharge ionization zone. The charged (ionized) particulates are attracted to grounded collection plates that are maintained in an electric field. The particulates collect on the plates and are thus removed from the gas stream. Particulates are removed from the plates by periodic rapping into a hopper. ESPs are feasibly used in the wood products industry. This is reflected in recently permitted biomass-fired boilers at similar facilities, which were equipped with ESPs to control filterable PM emissions (RBLC IDs SC-0149, ME-0040 and FL-0361).

PM_{10} emissions control via ESP was deemed technically feasible for this analysis. A vendor price quote was received from Wellons. However, the vendor states that the

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[19] EPA: Monitoring by Control Technique - Wet Scrubber For Particulate Matter https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-wet-scrubber-particulate-matter

current wet scrubbers can quench significant char being discharged by the furnace. Introduction of char into an ESP will cause fire and potential damage, so furnace tuning, and modifications will be required in that case.

6.1.5 Summary of PM_{10} Control Technologies

The PWL hogged fuel boiler currently must comply with the grain loading limit of 0.10 gr/dscf in accordance with OAR 340-226-0210(2)(b). The analysis has identified an ESP as the only technically feasible, add-on PM_{10} control technology for analysis using the four-factor methodology.

The following four-factor analysis reviews the economic, energy, and environmental impacts of installing an ESP on the boiler. It also reviews the schedule of installation and duration of impact.

6.2 Current Actual PM_{10} Emissions and Post-Control PM_{10} Emissions

The initial Q/d analysis used to trigger the four-factor analysis requirement was based on both the reported actual emissions and the PSEL for the entire facility. However, the four-factor analysis itself is focused on individual emission sources. The largest source of PM_{10} emissions is the hogged fuel boiler at the PWL facility. Therefore, this analysis will only review control technologies for PM_{10} emissions from PH2 since controlling emissions from the other emissions sources is either technically infeasible, will not be cost effective due to minimal actual emissions, or do not offer substantial benefit as described in Section 4.4.

<u>Current PM_{10} Emissions</u>

Since PH2 is already controlled for PM_{10} via the wet scrubbers, the analysis needs to consider an incremental improvement in emissions from the already controlled rate. Therefore, controlled emissions from the wet scrubbers are used as baseline emissions for the analysis to quantify the additional benefit of alternative control. This creates an "effective" improvement by assessing additional PM_{10} control via an ESP rather than the existing wet scrubbers. The permitted PM_{10} emission rate in Table 10 on page 22 of 08-0003-TV-01 was used to establish the baseline emission rate in the analysis. It represents the current "Emission Factors and Verification Testing" rate of PM_{10} for the hogged-fuel boiler. Therefore, the controlled PM_{10} emission rate from the existing wet scrubbers is 0.198 lb PM_{10} per 1000 lb (klb or Mlb) steam generation. Baseline emissions were calculated using the average boiler steam production rate for reporting years 2016 – 2019. The average boiler steam production rate was 295,671 klb/yr. Baseline PM_{10} emissions emitting from the wet scrubbers are estimated as follows:

$$0.198 \text{ lb/klb} * 295{,}671 \text{ klb/yr} \div 2000 \text{ lb/ton} = 29.3 \text{ tpy}$$

The emission factor of 0.198 lb/klb steam can also be expressed in units of pounds per million Btu (lb/MMBtu) based on the accepted heat input to steam output conversion of

1.50 MMBtu heat input to 1000 lb steam output (1.50 MMBtu/klb). The current boiler emission factor for PM_{10} emissions from the wet scrubber is equivalent to:

0.198 lb/klb ÷ 1.50 MMBtu/klb = 0.132 lb/MMBtu heat input

The additional potential reduction in PM_{10} emissions are then evaluated when upgrading to an ESP.

Dry-ESP Controlled PM_{10} Emissions

PWL received an estimate from the vendor, Wellons, to install a dry ESP for control of the hogged fuel boiler. The proposal includes achieving a target outlet emissions level of 0.05 lb/MMBtu. This includes a filterable emissions level of 0.045 lb/MMBtu and an estimated 0.005 lb/MMBtu of condensable emissions. The proposed outlet rate was confirmed via a review of BACT determinations for similar wood-fired boilers contained in the EPA RBLC database.

For this analysis, PWL has a final ESP PM_{10} emission rate of 0.05 lb/MMBtu. Therefore, the “additional” control in emissions from the wet scrubbers to an ESP equates to a reduction in emission rates from 0.132 lb/MMbtu to 0.05 lb/MMbtu. This represents the additional PM_{10} removal efficiency when using an ESP for control. The emission factor can be used to calculate ESP-controlled annual emissions as follows:

0.05 lb/MMBtu * 1.50 MMBtu/klb = 0.075 lb/klb
0.075 lb/klb* 295,671 klb/yr = 11.1 tpy

Therefore, the utilization of an ESP results in controlling an additional 18.2 tpy of PM_{10} in comparison to the existing wet scrubbers.

6.3 Factor 1: Cost of Compliance

A cost estimate for installation of an ESP on the hog fuel boiler has been developed based on the cost estimation procedure in Section 6, Chapter 3 of EPA’s Control Cost Manual [8]. A cost estimate is also provided by the ESP vendor (Wellons) with additional cost support provided by KH2A Engineering, Arctic Engineering, and PWL. A spreadsheet with the cost estimation procedure, calculations, and the final calculated cost effectiveness of an ESP is presented in Appendix C. The vendor quote is included in Appendix D.

6.3.1 ESP Data Inputs

ESPs are designed based on the volumetric flow of gas, the temperature of the gas stream, type of particulate, and the particulate inlet load and outlet load. These parameters can then be used to estimate ESP cost using the “Full SCA Procedure” [8]. The specific collection area (SCA) and the volumetric flow rate of the exhaust gas are used to calculate the square footage of the plate area. Figure 3.5 in the Control Cost Manual provides a cost estimate, from flange-to-flange, of the ESP based on the plate area. The Full SCA Procedure was not necessary for this evaluation because the vendor provided a recommended plate type and size for the ESP, however the EPA Control Cost

Manual was still utilized for the additional cost calculations. The flange-to-flange, field erected cost was used only to determine maintenance costs per EPA Control Cost Manual methodology. However, the flange-to-flange cost is not carried through to the total direct cost. Instead, the equipment costs, direct costs, and indirect installation costs were supplied by Wellons, KH2A, Arctic Engineering, and PWL. Annual cost and capital recovery cost methodology was utilized from the Control Cost Manual. [8]

Total direct cost was established by the Wellons quote of $1,340,000. An additional $400,000 was factored into the total capital investment to account for the removal and decommissioning of the two exiting wet scrubbers. Additional direct and indirect installation and design costs that are beyond the scope of the Wellons quote are included by KH2A, Arctic Engineering, and PWL to accommodate challenges around construction and modification to the existing site. These values were revised to account for specified retrofit difficulty instead of applying the overall retrofit factor. Therefore, a retrofit factor was not applied like the cost analysis for SNCR. Difficulties surrounding the retrofit of the boiler and exiting site layout are further discussed below. The costs and factors are included in the ESP cost evaluation spreadsheet.

The indirect installation costs account for engineering, construction and field expenses, contractor fees, start-up, performance testing, model study, and project contingencies. The provided costs account for the civil engineering, structural engineering, and site work problems that are described in Section 5.4.2 surrounding earthquake design and unsuitable soil conditions. All design and construction considerations for seismic activity and wind loading will be also required for all new or modified construction surrounding the installation of an ESP. Therefore, any work to the existing foundation or any new construction will also require extensive structural design and geotechnical engineering because of the proximity of the Cascadia subduction zone.

Overall, the largest difficulty surrounding the installation of an ESP is available space to accommodate all associated equipment. ***The current configuration at the facility does not have the appropriate space necessary to install an ESP which will require a 12' x 30' footprint or larger***. The current area is blocked by the plywood plant to the east, the boiler to the north, pneumatic baghouse to the south, and an egress area to the west which accesses the maintenance shop. So, the installation would require the decommission and removal of the two existing wet scrubbers which would require complete shutdown of the hogged-fuel boiler. A reconfiguration of other equipment in the area would be a potential requirement as well. Figures 6-1 and 6-2 further indicate the lack of space required for an ESP and the necessary removal of the wet scrubbers. Figure 6-1 shows the current layout at PWL and the existing wet scrubbers. Figure 6-2 provides a comparable ESP control unit at SCL. Costs are included in the evaluation to account for the decommissioning and removal of the wet scrubbers as well as site modifications.

Figure 6-1: Current Layout at PWL

Figure 6-2: Comparable ESP at South Coast Lumber for Scale

Accounting for the vendor quote, site preparation, direct, and indirect costs, the TCI calculates to $4,893,200 in 2020 dollars. Again, this does not apply a retrofit factor and instead is accounted for with adjusted costs.

Direct and indirect annual costs were calculated per Control Cost Manual [8] guidance. The references for the wage values and cost of electricity are noted in the calculation spreadsheet and included in Appendix C. Wage values were provided by PWL. The TCI was broken down into a Capital Recovery Cost over the assumed twenty years of equipment life and based on the recent Prime Rate of 3.25%. The discussions surrounding the estimated equipment life and interest rate in regard to the SNCR are also applicable to the ESP. Financing through SCL will likely be at a larger interest rate, however the prime rate is still used in the analysis. A 20-year expected life was also utilized for the ESP because the EPA Control Cost Manual states “20 years being typical” for the control technology.

A critical cost that is not quantified within the cost analysis is the lost revenue due to downtime of the boiler. Boiler downtime would halt LVL, plywood, and veneer operations at PWL. The boiler provides steam to the plywood plant and the plywood plant supplies the other operations with billet. So, boiler downtime effectively shuts down all operations. The cost associated with lost revenue would be critical from a production standpoint as well as the breech in contractual obligations to customers. Even more importantly, the facility would not have operations to provide their 300 employees with work throughout the period.

Total annual direct operations and maintenance (O&M) costs and indirect costs for capital recovery, taxes, insurance, and overhead are calculated at $670,846 per year.

6.3.2 Cost Effectiveness Calculation Results

The tons per year of PM_{10} removed were calculated based on the tons of PM_{10} emitted from the wet scrubbers controlling the boiler to provide an incremental control analysis. The wet scrubbers emit roughly 29.3 tpy of PM_{10}. Modification to an ESP equates to a controlled emission rate of 11.1 tpy based on the same steam production rate. This results in an additional reduction of 18.2 tpy of PM_{10} from the boiler when using an ESP. Cost per ton removed is calculated by dividing the total annual cost by the tons of PM_{10} removed, as shown below:

$670,846/yr ÷ 18.2 tons/yr = $36,893 per ton of PM_{10} removed.

The PM_{10} emissions control cost calculations are summarized in Table 6-1.

Table 6-1: Hogged Fuel Boiler Cost Effectiveness Analysis – PM_{10}

Control Technology	Reduced Emission Rate	Emissions (tons/year)	Emissions Reduction (tons/year)
Existing Multiclone and Wet Scrubbers	Base Case	29.3	Base Case
Fabric Filter Baghouse	Not feasible due to fire danger.		
Electrostatic Precipitator	0.05 lb/MMBtu	11.1	18.2
ESP Cost Parameters			
Boiler Steam Production Capacity	295,671,000 pounds of steam per year		
Estimated ESP Direct and Indirect Capital and Installation Costs	$4.9 million		
Total indirect annual costs, including capital recovery	$580,354		
Total direct annual O&M Costs	$90,492		
Total Annual Capital Recovery and O&M Costs	$670,846		
Cost per ton PM_{10} Removed[20]	$670,846 ÷ 18.2 tpy = $36,893/ton		

6.4 Factor 2: Time Necessary for Compliance

PWL estimates that it would take approximately 24 to 48 months to obtain ESP bids, review, award the contract, then design, permit, finance, install and commission an ESP on the hogged fuel boiler. The cost estimate does not account for lost revenue due to plant downtime required for the decommissioning of the wet scrubbers and construction of the ESP. There is not enough available space at PWL to construct an ESP while operation continues and then connect the boiler to the new control device. Instead, the entire facility would be required to shut down to accommodate the project.

6.5 Factor 3: Energy and Environmental Impacts of Compliance

Installing an ESP on boiler PH2 would increase the facility's energy consumption, which would have a negative environmental impact at the point of power generation in the form of air pollution, including greenhouse gases.

6.6 Factor 4: Remaining Useful Life

As stated in Section 5.7, the Riley hogged-fuel boiler was installed at PWL in 1986 and was originally commissioned in 1969. The boiler has been adjusted and tuned to efficiently operate with the PWL fuel source of coastal grown logs, recovery wood fiber

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[20] Cost per ton in table 6-1 is based on a 20-year expected equipment life. ESP installation with a 30-year expected life equates to $32,560 per ton PM_{10} removed.

from salvage logs, and sustained yield timber from the Company's timber lands. Most importantly, the boiler effectively processes residuals from fee timber lands. The remaining useful life of the boiler is considered to be at least the entire duration of the capital recovery period of the cost analysis.

7.0 COST EFFECTIVENESS COMPARISON

The EPA Draft Guidance on Progress Tracking [9] includes recommendations to rely on the cost effectiveness metric and comparisons to past regulatory actions. EPA recommends that a state consider the costs of compliance by comparing the cost/ton metric for a control measure to the same metric from other regulatory actions, in the manner explained in this section.

Cost effectiveness determinations are generally made to meet the requirements of Best Available Control Technology (BACT) requirements. BACT analyses are made on a case-by-case basis during site-specific industrial source permitting processes. The cost-effectiveness data for the BACT determinations is typically not included in the RBLC database. No publicly available cost information for BACT analyses on sources similar to the PWL hogged fuel boiler has been located.

Cost effectiveness determinations were also included in the regional haze Round 1 analysis to support BART determinations. The Oregon Round 1 analysis for regional haze focused on emissions control for a coal-fired power plant at Boardman, Oregon. The BART analysis for that facility concluded that emission control options costing more than $7,300 per ton would not be required [Federal Register Vol. 75, No. 128, July 5, 2011].

The Washington Round 1 regional haze analysis included BART analysis for two wood-fired power boilers. The evaluation found that replacement of the wet scrubber with a wet ESP on one boiler was not cost effective at a cost of $11,249/ton of PM_{10} removed. Washington also concluded that NO_x emissions controls costing $13,000/ton using SCR and $6,686/ton using SNCR would not be cost effective [Federal Register Vol. 77, No. 247, December 26, 2012].

The four-factor analysis for the PWL wood-fired boiler has determined that adding an ESP to further control PM_{10} emissions would have an effectiveness cost of $36,893/ton. This is higher than the costs that were identified in the Oregon and Washington Round 1 regional haze analyses as not being cost effective for PM_{10} control.

The four-factor analysis for the PWL wood-fired boiler has determined that adding an SNCR system to control NO_x would have an effectiveness cost of $28,912/ton. This is higher than the costs that were identified in the Oregon and Washington Round 1 regional haze analyses as not being cost effective for NOx control.

8.0 CONCLUSION

A four-factor analysis has been conducted for PWL's wood-fired boiler at the Brookings, Oregon plywood facility. The analysis was conducted to meet the requirements of Round 2 of the Regional Haze program to assist ODEQ with the development of a SIP. Regional Haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, ODEQ required PWL to perform this four-factor analysis.

The four factors analyzed were based on ODEQ guidance and the RHR to determine if there are emission control options at the Brookings facility that, if implemented, could be used to attain reasonable progress toward the state's visibility goals. The factors reviewed included the cost of compliance, time necessary for compliance, energy and environmental impacts, and the remaining useful life of the existing source subject to these requirements.

PWL considered all the emissions sources on the facility and found that the hogged fuel boiler provided the majority of the facility's PM_{10}, NO_x and SO_2 emissions. Therefore, the four-factor analysis was conducted for NO_x and PM_{10} on boiler PH2. SNCR installed on the boiler would have a cost effectiveness of $28,912 per ton of NO_x removed (in 2019 dollars). An ESP installed on the boiler would have a cost effectiveness of $36,893 per ton of PM_{10} removed (in 2019 dollars). Both pollution control technologies generate some level of energy and other environmental impacts. Both types of control would take two or more years to fully implement due to challenges surrounding space limitations as well as earthquake and soil stability design/construction.

Review of BART analyses prepared by Oregon and Washington state agencies for Round 1 of the regional haze process showed that the cost-effectiveness values were similar to those developed by PWL. Oregon and Washington state agencies concluded that these costs were too high to be cost effective, and EPA agreed.

The primary contributors of PM_{10} emissions impacting Oregon Class I areas, including the Kalmiopsis Wilderness, are wildfire, woodstove, and miscellaneous source emissions. While difficult to control or even affect these sources, their impacts nonetheless dominate. Industrial point sources of emissions are an easy target; however, these facilities are providing the economic means that enable people to invest in cleaner burning woodstoves and vehicles. Additionally, impairment from anthropogenic sources in the Kalmiopsis Wilderness are dominated by ammonium sulfate. PWL emits very little SO_2 emissions which act as a precursor pollutant to ammonium sulfate. Conversely, ammonium nitrate has very little contribution to impairment in the Kalmiopsis Wilderness. Therefore, a reduction of NO_2 emissions at PWL will provide little impact towards the improvement of visibility in the wilderness. Prior to imposition of controls on industry, ODEQ needs to ensure that those requirements will have a discernable and causal impact on the improvement of visibility in the Class I areas. Enforced reductions to industrial emissions that are minimal or non-contributing factors to regional haze in a Class I area will neither improve visibility nor contribute to the reasonable progress goals of the Regional Haze program.

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APPENDIX A: COMMUNICATIONS WITH ODEQ

Oregon
Kate Brown, Governor

Department of Environmental Quality
Agency Headquarters
700 NE Multnomah Street, Suite 600
Portland, OR 97232
(503) 229-5696
FAX (503) 229-6124
TTY 711

Certified Mail

December 23, 2019

Pacific Wood Laminates, Inc.
PO Box 820
Brookings, OR 97415-0200

Re: Regional Haze Four Factor Analysis; Pacific Wood Laminates, Inc.

Dear Pacific Wood Laminates, Inc.:

The purpose of this letter is to inform you that the Oregon Department of Environmental Quality (DEQ) has identified the Pacific Wood Laminates, Inc. as a as a significant source of regional haze precursor emissions to a Class I area in Oregon, thus triggering the need for a four factor analysis under the regional haze program. Please complete this analysis and submit it by May 31, 2020.

Background

The Oregon Department of Environmental Quality (DEQ) is required to develop and implement air quality protection plans to reduce the pollution that causes haze at national parks and wilderness areas, known as Federal Class I areas. This requirement can be found at 40 CFR 51.308 and 42 U.S.C. § 7491(b), and is implemented under the authority of ORS 468A.025.

DEQ submitted its first regional haze state implementation plan (SIP) in 2010 and is required to submit a revision in 2021 to address the second planning period, 2018-2028. In this revision, Oregon is required to update the long-term strategy that addresses regional haze visibility impairment in each of the twelve Class I areas within Oregon as well as the Columbia River Gorge National Scenic Area and those Class I areas outside of Oregon that are impacted by emissions from sources in Oregon.[1]

[1] The Class I Areas in Oregon are: Kalmiopsis Wilderness, Crater Lake National Park, Mountain Lakes Wilderness, Gearhart Mountain Wilderness, Diamond Peak Wilderness, Three Sisters Wilderness, Mount Washington Wilderness, Mount Jefferson Wilderness, Mount Hood Wilderness, Strawberry Mountain Wilderness, Eagle Cap Wilderness, and Hells Canyon Wilderness.

In establishing the long-term strategy, DEQ must evaluate and determine emission reduction measures necessary to make reasonable progress for each Class I area within Oregon. Per 40 CFR 51.308(f)(2) this evaluation should consider major and minor stationary sources, mobile sources, and area sources.

Guidance provided by the U.S. Environmental Protection Agency (EPA) indicates DEQ must address 80% of the visibility impairment caused by in-state sources.[2] Data from the EPA and National Park Service Visibility (IMPROVE) Program monitoring sites for Oregon's 12 Class I Areas indicate that sulfates, nitrates, and coarse mass continue to be significant contributors to visibility impairment in these areas. The primary precursors of sulfates, nitrates, and coarse mass are emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM_{10}).

DEQ has identified your facility as a significant source of regional haze precursor emissions. Based on the information in the table below, DEQ selected your facility to provide additional information about emissions and current and potential controls based on a screening evaluation of haze-causing emissions relative to distance to Class I Areas in Oregon.

DEQ Facility ID:	08-0003
Federal Facility ID:	8416611
Facility name:	Pacific Wood Laminates, Inc.
Facility Address	815 N RAILROAD AVE
Facility City, State, Zip	BROOKINGS, OR 97415

Facility 2017 Emissions[3]

Actual (tons per year)				Potential to Emit (tons per year)			
NOx	SO2	PM-10	Total Q	NOx	SO2	PM-10	Total Q
52.5	3.27	139.1	194.9	76	29	189	294

Pursuant to OAR 340-214-0110, by this letter DEQ is requiring you to provide information that will help DEQ prepare its updated long-term strategy. Specifically, you must complete a four factor analysis of potential additional controls of haze precursor emissions, as described below. DEQ will review submissions for adequacy and may revise as necessary. DEQ will need to be able to verify the information submitted in your four factor analysis. In order for DEQ to be able to approve your submission, please be sure to provide all supporting documents that are not publicly available, including emissions factors and calculation methods. DEQ will consider

[2] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, (August 2019), EPA-457/B-19-003. pp. 31 – 34, https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period.

[3] Annual emissions data taken from the 2017NEIDRAFT data for stationary sources released August 2019 (https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data). Potential to emit information taken from facility permits in TRAACS.

submissions incomplete if submitted without supporting information. The analysis should be prepared using the EPA guidance referenced above as well as EPA's Air Pollution Control Cost Manual[4] and EPA's Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze.[5] Please complete the analysis for every emission point at your facility. If a unit is too small to control, please demonstrate that.

If you fail to submit your four factor analysis to DEQ by May 31, 2020, you may be subject to enforcement, including civil penalties.

Four Factor Analysis

Based on our evaluation, your facility warrants an analysis to be included in DEQ's SIP submittal, which could mean that additional emission controls will be required. As outlined in 40 CFR 51.308(f)(2), DEQ must evaluate four factors to determine whether specific control measures for your facility are reasonable and should be included in an updated long-term strategy. By this letter, DEQ is requiring you to provide information and analysis of the four factors. These four factors are:

1) The costs of compliance.
2) The time necessary for compliance.
3) The energy and non-air quality environmental impacts of compliance.
4) The remaining useful life of any potentially affected major or minor stationary source or group of sources.

DEQ looks forward to your submittal of a four factor analysis for these emission units and pollutants as soon as practicable, but no later than May 31, 2020. We encourages you to share drafts with us for comments and we are prepared to engage in consultation to ensure an approvable submittal before the deadline.

DEQ will host an **informational webinar on the Regional Haze Program and the four factor analysis** at 10:00 am on January 9, 2020. The conference call and webinar information is as follows: Call in number: 888-557-8511; Participant Code: 9544452; Web link: https://www.teleconference.att.com/servlet/AWMlogin

For more information, please see https://www.oregon.gov/deq/aq/Pages/Haze.aspx.

[4] EPA, "EPA Air Pollution Control Cost Manual." https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. Please refer to the most current finalized version of the relevant chapters.

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

APPENDIX B: SELECTIVE NON-CATALYTIC REDUCTION COST ANALYSIS CALCULATIONS

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

<u>Step 1</u>: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

<u>Step 2</u>: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

<u>Step 3</u>: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

<u>Step 4</u>: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

<u>Step 5</u>: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn?

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Factor not adjusted. Retrofit difficulty instead accounted for in additional Capital Costs evaluated by KH2A Engineering, Arctic Engineering, and PWL.

Complete all of the highlighted data fields:

		Note
What is the maximum heat input rate (QB)?	86 MMBtu/hour	a
What is the higher heating value (HHV) of the fuel?	17,480,000 Btu/BDT	b
What is the estimated actual annual fuel consumption?	27,883 BDT/Year	c
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	17.5 MMBtu/MW	d

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR	
Coal	10 MMBtu/MW	
Fuel Oil	11 MMBtu/MW	
Natural Gas	8.2 MMBtu/MW	
Biomass	1 BDT/MW	d

Provide the following information for coal-fired boilers: **NOT APPLICABLE**

Type of coal burned:

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate:

Ash content (%Ash): percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted

Enter the following design parameters for the proposed SNCR:

		Note		
Number of days the SNCR operates (t_{SNCR})	336 days	e	Plant Elevation	102 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.2458 lb/MMBtu	f	59.89	
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1450 lb/MMBtu	g	35.33	
Estimated Normalized Stoichiometric Ratio (NSR)	1.99 Must be <2.0, above that no eff. increase and ammonia slip	h	*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).	

Concentration of reagent as stored (C_{stored})	50 Percent
Density of reagent as stored (ρ_{stored})	71 lb/ft^3
Concentration of reagent injected (C_{inj})	10 percent
Number of days reagent is stored ($t_{storage}$)	14 days
Estimated equipment life	20 Years
Select the reagent used	Urea

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

				Note
Desired dollar-year	2019			
CEPCI for 2019	607.5 CEPCI Annual Avg. for 2019	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25 Percent	***Current Prime Rate - See note h***		i
Fuel ($Cost_{fuel}$)	2.00 $/MMBtu			j
Reagent ($Cost_{reag}$)	1.66 $/gallon for a 50 percent solution of urea*			
Water ($Cost_{water}$)	0.0042 $/gallon*			
Electricity ($Cost_{elect}$)	0.0676 $/kWh*			
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	$/ton			

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	-	Select fuel type	
Ash Disposal Cost ($/ton)	-	Select fuel type	
Percent sulfur content for Coal (% weight)	-	Select fuel type	
Percent ash content for Coal (% weight)	-	Select fuel type	
Higher Heating Value (HHV) (Btu/lb)	-	Select fuel type	
Interest Rate (%)	5.5	Default bank prime rate	

User Input Notes

a The rated capacity of the boiler is 86 MMBtu/hr per 08-0003-TV-01.

b HHV of hog fuel is 17.48 MMBtu/ton per GHG Baseline Emissions in 08-0003-TV-01.

c Four year average (2017 - 2019) of actual annual fuel production (BDT/year). See PWL Reference Values tab.

d NPHR value adjusted for Biomass fuel. http://www.ucanr.org/sites/WoodyBiomass/newsletters/InfoGuides43283.pdf
8000 - 10,000 BDT/year = 1 MW; over 8760 hours per year equates to approx. 1 BDT/MW
(17,480,000 btu/BDT) x (MMBtu/10^6 btu) x (1 BDT/MW) = 17.48 MMBtu/MW

e PH2 boiler maximum operating schedule is 8,064 hours per year per Current Plant Site Operating Limits (24.b.) in 08-0003-TV-01.

f Inlet NOx ratio based on source test data from June 11, 2019. Inlet NOx (lb/MMBtu) represented by average rate from test.

g Outlet NOx emissions based on requirement to keep Normalized Stoichiometric Ratio (NSR) below 2.0 to avoid ammoinia slip. Results in ~41% control efficiency.

h NSR calculated using Equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost manual.

$$NSR = \frac{[2\,NO_{X_{in}} + 0.7]\eta_{NO_x}}{NO_{X_{in}}}$$

i Current prime rate of 3.25%. The rate one year ago was at 5.5% which is considered default value in OAQPS spreadsheet.

j Fuel Cost is based on $35/BDT, delivered, and 17.5 MMBtu/BDT.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	86	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	43,098	BDT/Year	
Actual Annual fuel consumption (Mactual) =		27,883	BDT/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.75		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.60	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5217	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	41	percent	***NOTE: Limited to 41% to prevent ammonia slip as dictated by NSR***
NOx removed per hour =	NOx_{in} x EF x Q_B =	8.67	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	22.60	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 102 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	27	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	55	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	5.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	2,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0688

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)$/NPHR =	1.1	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	26	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x $((1/C_{inj})-1)$ =	0.22	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$800,000	in 2019 dollars	*Wellons Quote*
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars	*Spreadsheet Calculated*
Balance of Plant Costs (BOP_{cost}) =	$523,656	in 2019 dollars	
Civil and Structural Engineering	$600,000	in 2019 dollars	*KH2A, Arctic, and PWL Provided*
Building Costs, Site-Work, Concrete, Fire System	$1,800,000	in 2019 dollars	
Boiler Modification (ID Fan, F.D. Fan)	$3,150,000	in 2019 dollars	
CEMs System	$250,000	in 2019 dollars	
Total Capital Investment (TCI) =	$7,123,656	in 2019 dollars	*Total*

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$800,000	in 2019 dollars	**Vendor Quote (Wellons)**

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$523,656 in 2019 dollars	Spreadsheet Calculated

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$160,182 in 2019 dollars
Indirect Annual Costs (IDAC) =	$493,313 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$653,495 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash

Annual Maintenance Cost =	0.015 x TCI =	$106,855 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$50,039 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$398 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$572 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,317 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0 in 2019 dollars
Direct Annual Cost =		$160,182 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,206 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$490,108 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$493,313 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$653,495 per year in 2019 dollars
NOx Removed =	22.6 tons/year
Cost Effectiveness =	**$28,912 per ton of NOx removed in 2019 dollars**

Pacific Wood Laminates
PH2 Boiler Data

Fuel Consumption and Steam Production
Total Flow Per Year

Year	Steam Flow (lbs)	Fuel Input (BDT)	Fuel Efficiency (lbs Steam/BDT)
2019	281,997,260	24,924	11,314
2018	292,847,339	26,832	10,914
2017	303,542,239	31,200	9,729
2016	304,296,216	28,574	10,649
2016 - 2019 Avg.	*295,670,764*	*27,883*	*10,652*

Boiler operations continue to be refined and adjusted to accomplish higher operational efficiency.

Source Test Results - Inlet NOx Value
PH2 Boiler Controlled by Wet Scrubber 1 and 2
Compliance Source Test - June 11, 2019

APPENDIX C: ELECTROSTATIC PRECIPITATOR COST ANALYSIS CALCULATIONS

Pacific Wood Laminates (PWL) PH2 Hogged Fuel Boiler
Regional Haze Four-Factor Analysis

PM Control ***Replace Wet Scrubber(s) with Electrostatic Precipitator (ESP)***
The multiclone will remain upstream of the ESP

Key
Blue values are entered
Green values are referenced
Red values are calculated

Design Basis - PH2 Hogged Fuel Boiler			**Source**
Pollutant source	Wood-fired Boiler (Hogged Fuel and Sanderdust)		
Flow, max	53,903	ACFM	1
Temperature	490	deg. F	2
Basis of ton/yr calculations, boiler steam production	295,671	klb/yr	3

Year	Steam (klb)
2019	281,997
2018	292,847
2017	303,542
2016	304,296
Average	295,671

Hours of Operation of ESP for Calculations	8,064	hr/yr	4
Boiler Efficiency, MMBtu/Mlb Steam.	1.50	MMBtu/klb	5
Assumed equipment life	20	years	6
Data Used to Determine Tons of Emissions Controlled			
Steam Flow Rate Used for Calculations (referenced above)	295,671	klb/yr	
Current controlled PM10 emission factor (**Exiting wet scrubbers**)	0.198	lb/klb	7
ESP-controlled PM10 emission rate (**From Wellons**)	0.050	lb/MMBtu	8
ESP-controlled emission rate, converted units	0.075	lb/klb	
Current PM10 Wet Scrubber-Controlled Emissions (testing requirement)	29.3	ton/yr	
PM10 ESP-Controlled Emissions	11.1	ton/yr	
Additional PM10 removed (Wet scrubber to ESP)	18.2	ton/yr	

ESP Equipment for Control Cost Manual Calculations

https://www.in2013dollars.com/us/inflation/1999?endYear=2018&amount=100

From Figure 3.5: Plate area: 12,320 ft^2 **Wellons Proposal**

Flange-to-flange, field-erected, with standard options: $ 328,998 1987 dollars

Based on Wellons Plate Area

U.S. Bureau of Labor Statistics - Producer Price Index

Series ID: PCU33341333341311 Dust collection and other air purification equipment for industrial gas cleaning systems

Based on NAICS: 333413 Fan, blower, air purification equipment mfg

Base year: 1983 index = 100

Data available for 1989 through 2020 (1990 is the first year with full annual data)

Linearly interpolate between 1983 and 1990 to estimate index for 1987:

PPI for 1987 = 114.4 - (114.4-100)/(1990-1983)*(1990-1987) = 108.2

PPI for April 2020: 206.6 — Source 9

Adjustment ratio = Apr. 2020 PPI/1987 PPI = 1.91

Adjusted cost: $ 628,032 2020 dollars

COST ESTIMATE

Cost Item	Factor		Source
Total Capital Investment, TCI			
ESP + auxiliary equipment			
Flange-to-flange, field-erected, standard options, 2020 $		$ 628,032	
ESP + auxiliary equipment	A	$ 628,032	
(Used to calculate maintenance cost. Not included in total direct cost below. Already accounted for in Wellons quote.)			
Direct Costs			
Site preparation (Removal of Wet Scrubbers)		$ 400,000	12
Wellons Quote		$ 1,340,000	12
Direct installation costs (outside of Wellons quote)			
Foundation and supports (Additional earthquake design)		$ 950,000	12
Handling and erection		$ 320,000	12
Electrical (Boiler and adjacent infrastructure)		$ 200,000	12
Piping (New Duct Work to Unit, From I.D. Fan)		$ 50,000	12
Insulation for ductwork		$ 14,000	12
Painting		$ 14,000	12
Direct installation costs (subtotal)		$ 1,548,000	
Total Direct Costs, DC	**SP + Wellons Quote + Direct Installation**	**$ 3,288,000**	
Indirect Costs (Installation). Based on Contractor Input			
Engineering		$ 350,000	12
Cascadia earthquake design and certification			
Site design and re-arrangement due to space constraints			
Construction and field expenses		$ 750,000	12
Cascadia earthquake design and certification			
Site design and re-arrangement due to space constraints			
Contractor fees		$ 400,000	12
Project installation work			
Demolition of Old IWS Duct Work and Scrubber Tank			
Start-up		$ 15,000	12
Performance test		$ 15,000	12
Model study		$ 35,000	12
Contingencies	0.03*Wellons Quote	$ 40,200	12
Total Indirect Costs, IC		**$ 1,605,200**	
Total Capital Investment, TCI = DC + IC			
No retrofit factor applied.		**$ 4,893,200**	**2020 dollars**
Instead applied specific costs.			

Total Annual Costs, TAC									
Direct Annual Cost									
Operating labor, coordination						$	11,798		
Basis:	Annual mean wage	$		58,990					10
	Fraction of ESP time			0.2					11
	Fraction of ESP time * annual labor cost								
Operating labor, per shift						$	31,579		6
Basis:	Mean hourly wage	$		21.93	/hr				12
	Labor per shift			1	hr/shift				12
	Number of shifts			4	shift/day				12
	Operating days			360	day/year				12
Total operating labor						$	43,377		
Supervisory labor				0.15 L		$	6,507		6
					Total Annual Labor	**$**	**49,884**		
Maintenance labor						$	23,793		6
Basis:	Maintenance labor estimated at:								
				15	h/wk				6
				44	wk/yr				6
	Same wage as above	$		36.05	/hr				13
Maintenance materials				0.01 *	Equip cost	$	6,280		6
Basis:	Equip cost = A above	$		628,032					
					Total Annual Maintenance	**$**	**30,073**		6
Electricity (ESP)						$	7,812	Annual Avg Load	6
Basis:	Full load power use			14	kW				13
	Electricity ($Cost_{elect}$)			0.0692	$/kWh				14
Electricity (ID Fan)						$	2,722		6
Basis:	fan kWh/yr = 0.000181*ACFM*delta P*hr/yr								
	ACFM from above:			53,903	ACFM				12
	delta P, estimate:			0.5	in. H2O				11
				8,064	hr/yr				4
	additional fan kWh/yr =			39,338	kWh/yr				6
	Annual cost = fan kWh/yr * $/kWh (above)								
Do not include costs for compressed air and dust disposal.									
Direct Annual Costs Summary									
Total Annual Labor						$	49,884		
Total Annual Maintenance						$	30,073		
Electricity (ESP)						$	7,812		
Electricity (ID Fan)						$	2,722		
					Total Direct Annual Costs	**$**	**90,492**		

Indirect Annual Costs						
Capital recovery costs				$	336,652	6
Basis:	Capital Recovery Factor (CRF) * TCI					
	CRF = i $(1+ i)^n/((1+ i)^n - 1)$ =		0.0688			6
	Where n = Equipment Life and i= Interest Rate					
	Annual Interest Rate (i), percent		3.25			15
Administrative charges (includes taxes, insurance)				$	195,728	6
Basis:	0.04 * TCI					
Overhead				$	47,974	6
Basis:	60% * (operating + supervisory + coordination + maintenance labor + maintenance materials)					
From above:						
labor	operating	$ 31,579				
	supervisory	$ 6,507				
	coordination	$ 11,798				
	maintenance	$ 23,793				
materials	maintenance	$ 6,280				
		$ 79,957				
Indirect Annual Costs Summary						
Capital recovery costs				$	336,652	
Administrative charges (includes taxes, insurance)				$	195,728	
Overhead				$	47,974	
			Total Indirect Annual Costs	**$**	**580,354**	
Total Annual Costs Summary						
			Total Direct Annual Costs	$	90,492	
			Total Indirect Annual Costs	$	580,354	
			Total Annual Cost	**$**	**670,846**	
			Tons per year PM10 removed		18.2	
			Cost Effectiveness	**$**	**36,893**	**/ton PM_{10} removed**

*Sources:

1 Permit 08-0003, Review Report P. 7 of 43. Multiclone inlet Q, assume equals outlet Q.
2 Permit 08-0003, Review Report P. 7 of 43. Boiler outlet T, assume no ΔT in the multiclone.
3 Average boiler steam production (2016 - 2019). Representative actual production.
4 PH2 boiler maximum operating schedule is 8,064 hours per year per Current Plant Site Operating Limits (24.b.) in 08-0003-TV-01.
5 Boiler Efficiency conversion is 1500 Btu/lb steam (p. 90 of 94)
6 EPA Cost Control Manual, Section 6 Particulate Matter Controls, Chapter 3 Electrostatic Precipitators. September 1999. (20 years considered typical). See four-factor analysis report for more discussion.
7 Permit PM10 emission rate "Emission Factors and Verification Testing" reporting value, Table 10, page 22 of 94.
8 ESP guaranteed controlled emission rate, provided by Wellons.
9 PPI Apr 2020 - https://beta.bls.gov/dataViewer/view/timeseries/PCU33341333341311
10 May 2018 State Occupational Employment and Wage Estimates Oregon, U.S. Bureau of Labor Statistics https://www.bls.gov/oes/2018/may/oes_or.htm , occupation code 51-1011, Supervisors of Production and Operating Workers
11 Estimate
12 Provided by PWL, KH2A, and/or Arctic Engineering
13 Based on ESP Vendor information
14 Table 2.4 - 2018 Average Price of Electricity for industrial customers - https://www.eia.gov/electricity/annual/pdf/epa.pdf.
15 Prime Rate as of June 8, 2020: https://www.federalreserve.gov/releases/h15/

APPENDIX D: WELLONS COST QUOTE

From:	Brian Murphy
To:	Brian Murphy
Subject:	Rough budget estimates request
Date:	Thursday, June 11, 2020 4:19:27 PM

---------- Forwarded message ---------
From: **Ken Kinsley** <Ken.Kinsley@wellons.com>
Date: Fri, Apr 3, 2020 at 8:33 AM
Subject: rough budget estimates request
To: James De Hoog <polarbear.jd20@gmail.com>
Cc: nolanr@socomi.com <nolanr@socomi.com>, Andrew Israelson <Andrew.Israelson@wellons.com>, bob.vanwassen@gmail.com <bob.vanwassen@gmail.com>

James;

Wellons has been asked to provide some rough budget estimates for certain emissions control system possibilities for Pacific Wood Laminates existing, Riley, 50,000PPH capacity wood-fired boiler in Brookings.

SELECTIVE NON-CATALYTIC REDUCTION (urea injection) FOR NOX REDUCTION.
This technology injects a urea solution into an appropriate temperature zone of the boiler furnace for a chemical reaction that converts NOx to NO2 and water. Successful applications of this technology generally see a 50% reduction in NOx.
However, to be successful, the appropriate temperature zone must be identified and the furnace configuration analyzed to determine where the urea injection should occur, and to determine if there is enough residence time for the chemical reaction.
Additionally, the range of operating load must be evaluated. Injection optimized for full load operation may not be successful at partial loads.
Detailed engineering modeling of the boiler would be required to determine how to implement the addition of an SNCR systemj.

The following is a general description;

A urea-based selective non-catalytic reduction (SNCR) system to lower the NOx emissions in the flue gas from the boiler system. The SNCR system is designed to lower the uncontrolled NOx emissions in the stack flue gas by approximately 50%. The SNCR system injects an atomized urea solution (CO[NH2]2 + water) into the boiler combustion chamber. The urea injection will be controlled based on a signal from the flue gas NOx monitor in the exhaust stack (part of the Owner's CEMS system). The amount of urea required will depend on the amount of NOx to be removed from the flue gas.

Based upon an up-front engineering study, the injection locations inside the combustion chamber would be selected to have the proper flue gas temperatures, have good mixing of the urea with the flue gas, and have the proper residence time to convert the NOx and urea into nitrogen and water vapor.

Items to be determined during the engineering study:

-does the furnace configuration provide an adequate temperature window and residence time?

-will system adjustments for adequate urea injection result in increased CO emissions?

-how stable is the boiler operation, what is the required operating range?

-how would injection nozzles penetrate the furnace walls?

-is there adequate treated water and compressed air supplies?

-locations for tank, and system hardware?

-is there an "ammonia slip" limitation?

NOTE: in some applications the urea injection process creates additional non-condensable artifact compounds that increase the total system particulate level.

BUDGETARY INSTALLED COST ESTIMATE:..............................$800,000.00.

This estimate includes the urea storage tank, system piping, compressed air system, mixing, atomizing and injection skid, distribution manifolds and hoses, injection nozzles, control panels, controls logic and software, mechanical installation and field wiring, but does not include costs to modify the boiler, site work to accommodate the added equipment, equipment weather enclosures, upgrades to the existing boiler control system, or emissions monitoring and data acquisition equipment (CEMS) as needed to provide a stack NOx level signal to the injection controls.

DRY ELECTROSTATIC PRECIPITATOR (ESP) FOR FILTERABLE PARTICULATE REDUCTION

A multiple field, dry ESP could be added to the boiler system exhaust, although this would require the decommissioning of the existing wet scrubbers. Because these scrubbers also help remove HCl and VOCs it would be expected that these levels would increase.

Based upon available boiler information, and a target outlet emissions level of 0.05#/MMBtu (filterable particulate emissions level of 0.045#/MMBtu and an estimated 0.005 condensable outlet), a Wellons Size 6 ESP with an approximate collecting area of 12,320 square feet has been estimated. It has been assumed that the existing boiler system has an effective multiple cyclone collector for char removal upstream of the ESP.

Unfortunately, we cannot offer an effective ESP that has an overall height under 40 feet. This size #6 has a roof height of 45ft above grade, with rapper hardware on the roof extending another 7 feet. The ESP would discharge into a 4ft diameter grade mounted stack with a discharge height of 50 ft.

NOTE: the current installation of wet scrubbers can conceal the fact that significant char is being discharged by the furnace but quenched at the scrubbers. Introduction of char into the ESP will cause fires and potential ESP damage. Furnace tuning and control/operating modifications may be required if this is the case.

BUDGETARY INSTALLED COST ESTIMATE...$1,340,000.

Includes equipment, engineering & design, control system & software, continuous opacity monitor, standard foundations, mechanical installation & electrical wiring, start up support. You would need to add an allowance for ductwork from the existing boiler system to the ESP inlet (will depend on where the ESP is located). Electrical power, final ash handling & disposal provisions

Let us know if anything else is needed, or any questions.

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