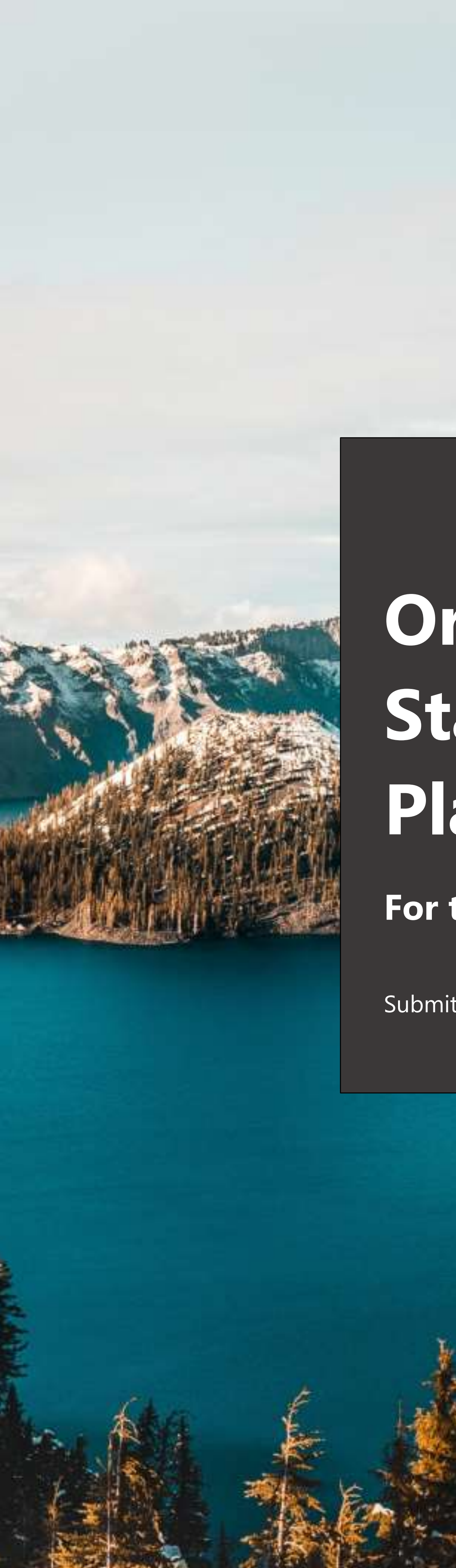

February 3, 2022

Oregon Regional Haze State Implementation Plan

For the period 2018 - 2028

Submitted for adoption: Oregon Environmental Quality Commission

Air Quality Planning

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Item C 000131

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Acknowledgments

The Western Regional Air Partnership provided significant assistance, much of the data and the technical support needed to meet the progress report requirements of Section 308(g)(h)(i) of the 2017 Regional Haze Rule. Special thanks to the following staff:

- Tom Moore, Western States Air Resources Council WESTAR, Western Governors' Association
- Bob Lebens, WESTAR
- Staff for WRAP Technical Support System, Cooperative Institute for Research in the Atmosphere (CIRA, Colorado State University) and Ramboll

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1. Introduction

EPA adopted the Regional Haze Rule in 1999 to improve and protect visibility in 156 national parks and wilderness areas across the country. This rule requires States to adopt regional haze plans and provide updates to these plans every 10 years. The Oregon Department of Environmental Quality adopted the first regional haze plan in 2009 and submitted a 5-year update in 2017. This document is the Regional Haze State Implementation Plan for the period from 2018 to 2028 and is submitted with the intention of fulfilling Oregon's requirements for the 1999 Regional Haze Rule, amended in 2017, under the Clean Air Act. DEQ refers to the 2017 Regional Haze rule throughout the rest of this document.

1.1. History of Regional Haze Planning in Oregon

The State of Oregon Environmental Quality Commission adopted the first Regional Haze plan in 2009. The plan included a comprehensive review of visibility conditions in each of Oregon's 12 Class 1 areas, with a projection of statewide emissions and visibility conditions in 2018, a summary of DEQ's BART, Best Available Retrofit Technology, evaluation of the PGE Boardman coal-fired power plant and other sources potentially subject to BART, and a reasonable progress demonstration for the best (clearest) and worst (haziest) visibility days, related to the 2018 milestone benchmark. In 2010, DEQ updated the Regional Haze Plan to incorporate rules that included new emission controls for PGE Boardman.

Under the federal 2017 Regional Haze Rule, states are required to develop five-year progress reports showing the latest visibility trends analysis and the current status for meeting reasonable progress milestones since the last submission of the plan. The 2017 progress report summarized changes in monitoring and emissions data since the plan was last adopted in 2010 and evaluated the adequacy of the current State Implementation Plan to meet the progress goals. The 2017 report concluded that visibility was continuing to show positive improvement, the plan was meeting the reasonable progress milestones, and no substantive revision was needed (**Error! Reference source not found.**).

This plan covers the period from 2018-2028 and includes the following chapters and sections. The following outline is based on Appendix D of the August 2019 *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*.[1]

Oregon DEQ commits to submitting the progress report by January 31, 2025 (cf. 40 CFR 51.308(f)).

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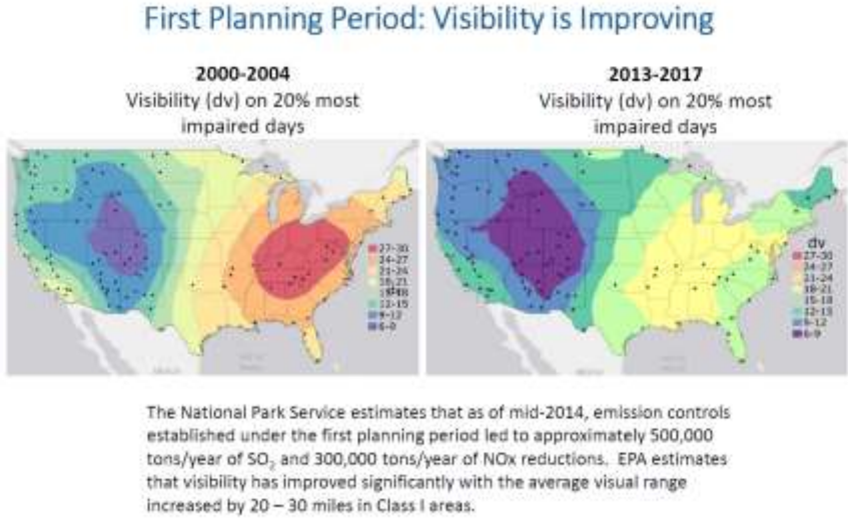
[1] US EPA. 2019. *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period.* *https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf* (Accessed January 13, 2021)

Figure 1-1: Visibility across the U.S. on the 20% most impaired days during the baseline period (2000-2004) to the most recent 5-year period (2013-2017). Source: EPA, September 2019.



1.2. Sections of this report

This document contains the following sections as required by the 2017 Regional Haze Rule for this period.

Table 1-1: Chapters and sections of this document, and the relevant 2017 Regional Haze Rule Provisions for each.

Step or Task	Relevant 2017 Regional Haze Rule Provision(s)
1) Introduction a) Short background on previous plans, including commitment to submit the 5-year progress report by January 31, 2025 b) This table	40 CFR 51.308(f)
c) Description of Class 1 areas and monitoring network	
d) Monitoring	
i) Submit a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all Class 1 areas within the state.	40 CFR 51.308(f)(6)
ii) Provide for the establishment of any additional monitoring sites or equipment needed to assess whether reasonable progress goals to address regional haze for all Class 1 areas within the state are being achieved.	40 CFR 51.308(f)(6)(i)
iii) Provide for procedures by which monitoring data and other information are used in determining the contribution of emissions from within the state to regional haze visibility impairment at Class 1 areas both within and outside the state.	40 CFR 51.308(f)(6)(ii)
iv) Provide for reporting of all visibility monitoring data to the Administrator at least annually for each Class 1 area in the state. To the extent possible, the state should report visibility monitoring data electronically.	40 CFR 51.308(f)(6)(iv)

Step or Task	Relevant 2017 Regional Haze Rule Provision(s)
v) Provide other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility.	CFR 51.308(f)(6)(vi)
2) An analysis of visibility monitoring data in Oregon's 12 Class 1 Areas and 5-year Progress Report a) Most Impaired Days i) Baseline and current visibility conditions for most impaired days for each Oregon Class 1 area ii) Natural visibility conditions for most impaired days for each Oregon Class 1 area iii) The difference between the baseline period visibility conditions and the current visibility conditions iv) The difference between the current visibility conditions and natural visibility conditions b) Clearest Days i) Baseline and current visibility conditions for clearest days for each Oregon Class 1 area ii) Natural visibility conditions for clearest days for each Oregon Class 1 area iii) The difference between the baseline period visibility conditions and the current visibility conditions iv) The difference between the current visibility conditions and natural visibility conditions	40 CFR 51.308(f)(1) 40 CFR 51.308(f)(5) 40 CFR 51.308(g)(1) through (5)
c) Emissions Inventory i) Provide for a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class 1 area. The inventory must include emissions for the most recent year for which data are available, and estimates of future projected emissions. The state must also include a commitment to update the inventory periodically.	40 CFR 51.308(f)(6)(v)
3) Stationary sources emissions analysis and controls	40 CFR 51.308(f)(2)(i)
a) An analysis of Class 1 Areas in other states that may be affected by emissions sources in Oregon	40 CFR 51.308(f)(2)
b) An analysis of sources in other states that may be reasonably anticipated to affect Class 1 Areas in Oregon	40 CFR 51.308(f)(2)(ii)
c) Select sources for analysis of control measures	40 CFR 51.308(f)(2)(i)
d) Identify emission control measures to be considered for these sources	40 CFR 51.308(f)(2)(i)
e) Characterize the four factors for these sources and measures	40 CFR 51.308(f)(2)(i)
f) Document the criteria used to determine the sources or groups of sources that have been evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in the long-term strategy (LTS).	40 CFR 51.308(f)(2)(i)
g) Document the technical basis, including information on the four factors and modeling, monitoring, and emissions information on which the state is relying to determine the emission reductions from anthropogenic sources in the state that are necessary for achieving reasonable progress towards natural visibility conditions in each Class 1 area it affects.	40 CFR 51.308(f)(2)(iii)
h) Identify the emissions information on which the state's strategies are based and explain how this information meets the Regional Haze Rule's requirements regarding the year(s) represented in	40 CFR 51.308(f)(2)(iii)

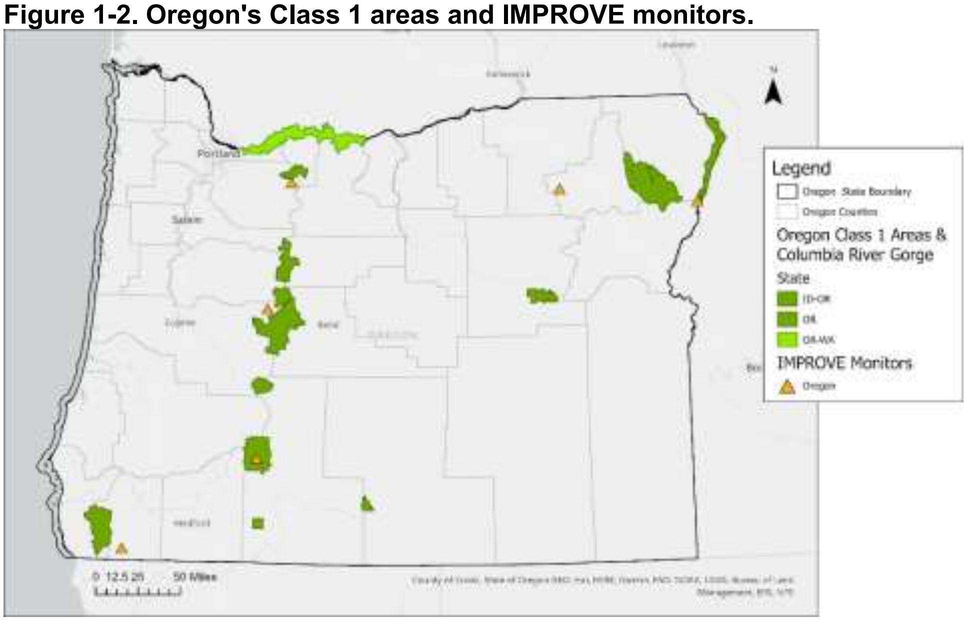
Step or Task			Relevant 2017 Regional Haze Rule Provision(s)
		the information, i.e., the tie to the submission of information to the NEI.	
	i)	Consider source retirement and replacement schedules.	40 CFR 51.308(f)(2)(iv)(C)
	j)	Set emission limits, averaging periods and monitoring and record keeping requirements.,	40 CFR 51.308(f)(2) – opening text
	k)	Set compliance deadlines.	40 CFR 51.308(f)(2) – opening text
4)	Long-term Strategy		40 CFR 51.308(f)(2)(i)
	a)	Consider emission reductions due to ongoing air pollution control programs, including measures to address RAVI.	40 CFR 51.308(f)(2)(iv)(A)
	b)	Consider measures to mitigate the impacts of construction activities.	40 CFR 51.308(f)(2)(iv)(B)
	c)	Consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs. After consideration of basic smoke management practices, states have the option to include the practices into their SIP submittal, but it is not required.	40 CFR 51.308(f)(2)(iv)(D)
	d)	An analysis of significant future trends in emissions	40 CFR 51.308(f)(2)(iv)(A)
	e)	Consider the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS.	40 CFR 51.308(f)(2)(iv)(E)
	f)	Select measures for inclusion in the LTS.	40 CFR 51.308(f)(2)
5)	Uniform Rate of Progress Glidepath Check		
	a)	Determine the URP using the baseline period visibility condition value and the natural visibility conditions value for the 20 percent most anthropogenically impaired days. The URP may be adjusted for impacts from anthropogenic sources outside the U.S. and from certain types of prescribed fires, subject to EPA approval as part of EPA's action on the SIP submission.	40 CFR 51.308(f)(1)(vi)
	b)	Compare 2028 RPG for the 20 percent most anthropogenically impaired days to the 2028 point on the URP glidepath. If the 2028 point is above the glidepath demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the state that may reasonably be anticipated to contribute to visibility impairment in the Class 1 area that would be reasonable to include in the LTS.	40 CFR 51.308(f)(3)(ii)
	c)	If the 2028 RPG for the 20 percent most anthropogenically impaired days is above the 2028 point on the URP glidepath, calculate the number of years it would take to reach natural conditions at the rate of progress provided by the SIP for the implementation period.	40 CFR 51.308(f)(3)(ii)(A)
	d)	Compare the 2028 RPG for the 20 percent clearest days to the 2000-2004 conditions for the same days, and strengthen the LTS if there is degradation. Also, compare the 2028 RPG for the 20 percent most anthropogenically impaired days to the 2000-2004 conditions for the same days, and strengthen the LTS if the RPG does not show an improvement.	40 CFR 51.308(f)(3)(i)
	e)	Project the 2028 RPGs for the 20 percent most anthropogenically impaired and 20 percent clearest days.	40 CFR 51.308(f)(3)
6)	Consultations with states through multi-state organizations and directly		40 CFR 51.308(f)(2)(ii)
	a)	Consult with those states that have emissions that are reasonably anticipated to contribute to visibility impairment in the	40 CFR 51.308(f)(2)(ii)

Step or Task	Relevant 2017 Regional Haze Rule Provision(s)
in-state Class 1 areas to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress. This consultation could include the exchange of relevant portions of analyses of control measures and associated technical information.	
b) Include in the SIP all measures agreed to during state to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.	40 CFR 51.308(f)(2)(ii)(A)
c) Consider the emission reduction measures identified by other states for their sources as being necessary to make reasonable progress in the Class 1 area.	40 CFR 51.308(f)(2)(ii)(B)
d) Include in the SIP a description of the actions taken to resolve any disagreements with other states regarding measures that are necessary to make reasonable progress at jointly affected Class 1 areas.	40 FR 51.308(f)(2)(ii)(C)
e) Consultations with Federal Land Managers for all Oregon Class 1 areas and affected out-of-state Class 1 areas on an ongoing basis	40 CFR 51.308(i)(4)
f) Offer an in-person consultation meeting with responsible FLMs at a point early enough in the state's policy analyses of its LTS emission reduction obligation so that information and recommendations provided by the Federal Land Manager can meaningfully inform the state's decisions on the LTS.	40 CFR 51.308(i)(2)
g) Include in the SIP submission a description of how the state addressed any comments provided by the FLMs.	40 CFR 51.308(i)(3)

1.3. Oregon Class 1 Areas

Oregon has 12 designated Class 1 areas, including Crater Lake National Park and 11 wilderness areas. These areas, the focus of Oregon Regional Haze Plan, are shown in **Error! Reference source not found.**.

Figure 1-2. Oregon's Class 1 areas and IMPROVE monitors.



1.3.1. Mt. Hood Wilderness Area

The Mt Hood Wilderness Area consists of 47,160 acres on the slopes of Mt Hood in the northern Oregon Cascades. Wilderness elevations range from 3,426 m (11,237 ft.) on the summit of Mt Hood down to almost 600 m (2,000 ft.) at the western boundary. It is almost adjacent to the Portland Oregon metropolitan area; the westernmost boundary is about 20 km east of the Portland Oregon suburb of Sandy and 40 km from the heavily populated metropolitan center, elevation 100 m (300 ft.). Visitation to the Mt. Hood Wilderness Area is approximately 50,000 visitors a year, primarily between May and October. Most visitors come from the Portland/Vancouver area that has a population of approximately 2 million.

1.3.2. Mt. Jefferson Wilderness Area

The Mt. Jefferson Wilderness Area consists of 107,008 acres on the crest of the Cascade Range in central Oregon. Its southern boundary is a few km north of the northern boundary of the Mt Washington Wilderness and it extends 40 to 50 km north along the Cascade crest. West of the crest, it consists primarily of the eastern side of the North Santiam River headwaters basin that connects to the Willamette Valley source region near Salem Oregon, 100 km (60 mi) to the west. East of the crest it occupies the western slopes of the Metolius River drainage that connects eastern slopes with Deschutes River in eastern Oregon. The highest Wilderness elevation is 3,200 m (10,497 ft.) at the summit of Mt Jefferson in the northern part of the Wilderness. Lowest Wilderness elevations are near 1,000 m (3,000 ft.) along the western boundary in the North Santiam headwaters basin and along the eastern boundary in the Metolius River basin.

1.3.3. Mt. Washington Wilderness Area

The Mt. Washington Wilderness Area consists of 52,516 acres on the crest of the Cascade Range in central Oregon. Like the Three Sisters Wilderness that it borders to the south, it includes headwaters tributaries of the McKenzie River that flow west into the Willamette Valley near Eugene and connect the Wilderness with that source region. On the east side eastern slopes of the Cascades descend to the Deschutes River near Bend. The highest Wilderness elevation is 2,376 m (7,794 ft.) at the summit of Mt Washington. Lowest elevations are near 900 m (3,000 ft.) in the upper headwaters basin of the McKenzie River.

1.3.4. Three Sisters Wilderness Area

The Three Sisters Wilderness Area consists of 285,202 acres abreast the crest of the Cascade Range in central Oregon. It includes headwaters tributaries of the McKenzie River that flow west into the Willamette Valley near Eugene and connect the Wilderness with that source region. On the east side streams flow east to the Deschutes River near Bend. The highest crest elevation is 3,158 m (10,358 ft.) at the summit of the South Sister. Lowest elevations are near 600 m (2,000 ft.) where the South Fork of the McKenzie River exits the Wilderness on the west boundary. This is about 500 m (1,600 ft.) above the Willamette Valley at Eugene 70 km (40 mi) west.

1.3.5. Diamond Peak Wilderness Area

The 52,337 acre Diamond Peak Wilderness Area straddles the Cascade Range 50 km (30 mi) north of Crater Lake National Park. The highest crest elevation in the Wilderness is 2,666 m (8,744 ft.) at Diamond Peak, which is also the highest summit in this region of the Cascade Range. Lowest elevations are near 1,450 m (5,000 ft.) where streams exit the Wilderness on the west side. On the east side the Wilderness is bordered by mountain lakes with elevations from 1,459 m to 1,693 m (4,786 to 5,553 ft.). The area includes headwaters of the Middle Fork of the

Willamette River that flows to the Willamette Valley near Eugene, elevation 100 m (300 ft.) and 90 km (60 mi) distant. Wilderness elevations are thus some 1,400 m (4,600 ft.) above the Willamette Valley floor. East of the Cascade crest, streams flow to the Deschutes River in eastern Oregon.

1.3.6. Crater Lake National Park

Crater Lake National Park is the only national park in Oregon. The park was established on May 22, 1902, and now consists of 183,315 acres. It is located in southwestern Oregon on the crest of the Cascade Mountain range, 100 miles east of the Pacific Ocean. Rim elevations range from about 900 to 1,873 ft. above lake level. The highest park elevation is 8,929 ft. at the peak of Mt. Scott, in the eastern Park area. The National Park includes headwaters of the Rogue River that flows southwest towards the Medford/Grants Pass area, and Sun Creek/Wood River that flows southeast to the Klamath Falls area.

1.3.7. Mountain Lakes Wilderness Area

The Mountain Lakes Wilderness Area is a relatively small Class 1 Area in southern Oregon of 23,071 acres, 50 km (30 mi) south of Crater Lake National Park. It consists of several peaks with a highest elevation of 2,502 m (8,208 ft.) at the crest of Aspen Butte. Lowest elevations are near 1,500 m (5,000 ft.). Primary drainages are Varney Creek and Moss Creek that flow into the Upper Klamath Lake, 3 km northeast of the Wilderness boundary.

1.3.8. Gearhart Mountain Wilderness Area

The Gearhart Mountain Wilderness Area consists of 22,809 acres on the flanks of Gearhart Mountain in south central Oregon, primarily the northern slope and eastern drainages of Gearhart Mountain, the dominant topographic feature. Elevations range from near 5,900 ft. at the North Fork of the Sprague River in the northern Wilderness to 8,364 ft. at the summit of Gearhart Mountain.

1.3.9. Kalmiopsis Wilderness Area

The Kalmiopsis Wilderness Area consists of 179,700 acres and is managed by the U.S. Forest Service. The Kalmiopsis Wilderness is located in the Klamath Mountains of southwestern Oregon, part of the coastal temperate rainforest zone that lies between the Pacific Ocean and the east side of the coast ranges in northwestern U.S. and Canada. Its western boundary is 20 to 25 km (12 to 15 mi) from the coast. Its easternmost extent is about 40 km (25 mi) from the coast. Elevations range from about 300 m (900 ft.) on the western boundary where the Chetco River exits the Wilderness towards the Pacific Ocean 25 to 30 miles further west, to 1,554 m (5,098 ft.) on Pearsoll Peak on the eastern Wilderness boundary. Terrain is steep canyons and long broad ridges. The Wilderness is mostly west of the general crest of the coast range, thus exposed to precipitation caused by lifting of eastward moving maritime air, primarily during the winter. Precipitation ranges from 150 to 350 cm (60 to 140 in) annually, depending on elevation.

1.3.10. Strawberry Mountain Wilderness Area

The Strawberry Mountain Wilderness Area consists of 69,350 acres in eastern Oregon, just east of John Day. The Wilderness comprises most of the Strawberry Mountain Range. Terrain is rugged, with elevations ranging from 1,220 m (4,000 ft.) to 2,755 m (9,038 ft.) at the summit of Strawberry Mountain. It borders the upper John Day River valley to the north.

1.3.11. Eagle Cap Wilderness Area

The Eagle Cap Wilderness Area consists of 360,275 acres in northeastern Oregon. Terrain is characterized by bare peaks and ridges and U-shaped glaciated valleys. Elevations range from 5,000 ft. in lower valleys to near 10,000 ft. at the highest mountain summits. The Lostine and Minam Rivers flow north from the center of the Wilderness towards Pendleton and the Columbia, 130 km northwest.

1.3.12. Hells Canyon Wilderness Area

The Hells Canyon Wilderness Area consists of 214,944 acres, and is located on the Oregon-Idaho border. The Snake River divides the wilderness, with 131,133 acres in Oregon, and 83,811 acres are in Idaho. It is managed by the Bureau of Land Management and the Forest Service. The Snake River canyon is the deepest river gorge in North America. The higher terrain is located on the Oregon side. Popular Oregon-side viewpoints are McGraw, Hat Point, and Somers Point.

1.4. Columbia River Gorge National Scenic Area

The 2017 Regional Haze Rule is applicable to federal Class 1 areas only (40 CFR 51.308(d)). While the Columbia River Gorge National Scenic Area is not a Class 1 area, it was designated a National Scenic Area by Congress in 1986. The area consists of 292,500 acres, running from the mouth of the Sandy River to the mouth of the Deschutes and spanning southern Washington and northern Oregon. The National Scenic Area Act of 1986 requires the protection and enhancement of the scenic, natural, cultural, and recreational resources of the Gorge, while at the same time supporting the local economy.

The Columbia River Gorge Commission has responsibility to administer the National Scenic Area Act. As part of a 2000 amendment to the National Scenic Area Management Plan, the CRGC recognized that a Class 1 designation is not appropriate for the Gorge. However, the CRGC did recognize that air quality degradation can jeopardize those resources, and that in order to protect air quality in the Gorge, the CRGC would have the state air quality agencies conduct a study, develop an air quality strategy for the Scenic Area, and provide annual reports regarding implementation of the strategy.

After a comprehensive study and extensive public process, the Oregon DEQ and Southwest Clean Air Agency completed the Columbia River Gorge Air Study and Strategy in 2011.[2] The Strategy proposed that Gorge visibility be monitored, evaluated and improved through the framework of the Regional Haze program. The goal for visibility in the Gorge is continued improvement, the same approach used in the federal Regional Haze Program. Additionally, the Gorge Visibility Study attributed most visibility impairment to regional, rather than local, sources of haze-forming pollutants. The rationale is that visibility improvement in the Gorge can be expected to mirror the visibility improvement in Class 1 areas such as Mt. Hood and Mt. Adams that will be achieved by emission reduction strategies adopted through the regional haze plans. The Gorge Commission approved the Strategy in 2011, and the agencies provide annual reports to the Commission as they implement the Strategy.

[2] https://www.swcleanair.gov/docs/ColumbiaRiverGorge/ColumbiaGorgeAirStrategyDocument-Final.pdf

1.5. Monitoring

1.5.1 Oregon IMPROVE Monitoring Network

In the mid-1980's, the Interagency Monitoring of PROtected Visual Environments (IMPROVE) program was established to measure visibility impairment in mandatory Class 1 Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, Western States Air Resources Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management.

The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class 1 federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the 2017 Regional Haze Rule by providing regional haze monitoring representing all visibility-protected federal Class 1 areas where practical.

In Oregon there are six IMPROVE monitors that are listed under the site name in Table 1-2. Three are located in the Oregon Cascades, two in Eastern Oregon, and one in the Coast Range. Since there are 12 Class 1 areas in Oregon, some monitors serve multiple Class 1 areas.

Table 1-2. Oregon IMPROVE Monitoring Network and Class 1 areas covered by each.

Site Code	Class 1 Area	Sponsor	Elevation MSL	Start Date
MOHO1	Mt. Hood Wilderness	USFS	1531 m (5022 ft.)	3/7/2000
THSI1	Mt. Jefferson Wilderness Mt. Washington Wilderness Three Sisters Wilderness	USFS	885 m (2903 ft.)	7/24/1993
CRLA1	Crater Lake National Park; Diamond Peak Wilderness Mountain Lakes Wilderness Gearhart Mountain Wilderness	NPS	1996 m (6548 ft.)	3/2/1988
KALM1	Kalmiopsis Wilderness	USFS	80 m (262 ft.)	3/7/2000
STAR1	Strawberry Mountain Wilderness Eagle Cap Wilderness	USFS	1259 m (4130 ft.)	3/7/2000
HECA1	Hells Canyon Wilderness Area	USFS	655 m (2148 ft.)	8/1/2000

1.5.2 Monitoring strategy

Oregon will continue to participate in the IMPROVE monitoring network to measure, characterize and report aerosol monitoring data for long-term reasonable progress tracking. DEQ commits a portion of Oregon's PM2.5 EPA funding to support the IMPROVE network. DEQ deems the IMPROVE network representative of conditions in all of Oregon's Class 1 areas and would rely on the IMPROVE Steering Committee to advise states if conditions changed such that additional monitors were necessary. DEQ also deploys two summer visibility nephelometers at Government Camp (Mt Hood) and Crater Lake July through September. DEQ and the nearby communities refer to the monitors for local information, particularly related to wildfire smoke.

Oregon's continued reliance on the IMPROVE network assumes the network's maintenance by Federal Land Management agencies and other Western Regional Air Partnership[3] members (states, tribes, and EPA). Oregon expects that operations and maintenance will continue to include data collection, analysis, quality assurance, and reporting. Oregon expects that FLMs will continue to make IMPROVE data available to the public through WRAP-supported web platforms such as the Technical Support System[4] and Federal Land Manager Environmental Database.[5]

2 Visibility Impairment in Oregon Class 1 areas and 5-year Progress Report

The federal 2017 Regional Haze Rule requires states to address visibility protection for regional haze in Class 1 Areas in each state. This chapter of the 2018 - 2028 Regional Haze Plan addresses the requirements for states to present calculations of baseline, current visibility, natural visibility conditions, progress to date, and a comparison to a uniform rate of progress [40 CFR 51.308(f)(1)]. Regional Haze is defined in EPA's August 2019 Guidance on Regional Haze as:

> "Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." This visibility impairment is a result of anthropogenic emissions of particles and gases in the atmosphere that scatter and absorb (i.e., extinguish) light, thus acting to reduce overall visibility.[6]

In Oregon there are 12 mandatory federal Class 1 areas, including Crater Lake National Park and 11 wilderness areas. DEQ includes the Columbia River Gorge National Scenic Area in Oregon's Regional Haze analyses (see **Error! Reference source not found.**). The U.S. EPA requires states to adopt regional haze plans that would improve Class 1 area visibility on the most impaired days – the worst 20 percent with some proportion of wildfire-impacted days removed; and ensure no degradation on the clearest days over the next 40 years. The goal of

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[3] The Western Regional Air Partnership (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/

[4] https://views.cira.colostate.edu/tssv2/

[5] https://views.cira.colostate.edu/fed/

[6] U.S. EPA. 2019. *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,* page 2. https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf (Accessed 1/20/21)

the 2017 Regional Haze Rule is to return visibility in Class 1 areas to natural background levels by the year 2064.

EPA provides guidance[7] for states to follow to establish baseline visibility and track visibility from baseline to 2018. The EPA guidance also outlines an adjustment process to distinguish the relative contributions from U.S. anthropogenic and natural sources. Because natural visibility can only be estimated, visibility impairment is calculated in units of daily light extinction, rather than directly measured. The first step in the haze analysis is to divide the daily light extinction into natural and anthropogenic fractions during days when visibility is poor, termed Most Impaired Days. A statistical method is used to estimate the fractions of natural and anthropogenic extinction for monitoring data. The EPA guidance cited below describes the current recommended methodology for determining the MID and the relative fractions of extinction (natural and anthropogenic) occurring on those days.

2.1 Five-year Progress Report

The 2017 Regional Haze Rule requires periodic reports that describe a state's progress toward reasonable progress goals. A state must submit progress reports every five years after submitting its first Regional Haze Plan [40 CFR Section 51.308(g)]. DEQ submitted the most recent 5-year Progress Report and Update to EPA in July 2017, which presented data analysis for the period 2010 – 2014 and 2018 Reasonable Progress Goals.

As this Round 2 Regional Haze Plan is a comprehensive revision to satisfy the requirements of 40 CFR Section 51.308(f), DEQ submits this Section 2.1 as the required 5-year progress report [40 CFR 51.308(f)(5)]. The Regional Haze Rule allows the plan revision to serve also as a progress report, as long as the plan revision addresses the requirements of 40 CFR 51.308 (g)(1) through (5). The period that the progress report should address for these elements shall be the period since the most recent progress report, in this case 2014 – 2018. Three of the required elements of a 5-year progress report are covered in other sections of this Round 2 Regional haze plan. The remaining two required elements of a 5-year progress report are described in the following sections.

Table 2-1 shows baseline monitored conditions (2000-04), 2018 Reasonable Progress Goals, current visibility (2014 – 2018), and estimated natural conditions in 2064 for the 20% worst and best days for Oregon's 12 Class I areas.

[7] Technical Guidance on Tracking Visibility Progress (2018); Memo and Technical Addendum on Ambient Data Usage (2020).

Table 2-1: Five-year progress report comparison of current visibility with 2018 Reasonable Progress Goals.

IMPROVE Monitor	Oregon Class I Area	20% Worst Days				20% Best Days		
		2000-04 Baseline (dv)	2018 Reasonable Progress Goal (dv)	Current Visibility (2014 – 2018) (dv)	2064 Natural Conditions (dv)	2000-04 Baseline (dv)	2018 Reasonable Progress Goal (dv)	Current Visibility (2014 – 2018) (dv)
MOHO	Mt. Hood Wilderness Area	14.9	13.8	9.27	8.4	2.2	2.0	1.39
THSI	Mt. Jefferson, Mt. Washington, and Three Sisters Wilderness Areas	15.3	14.3	11.46	8.8	3.0	2.9	2.61
CRLA	Crater Lake National Park; Diamond Peak, Mountain Lakes, and Gearhart Mountain Wilderness Areas	13.7	13.4	7.98	7.6	1.7	1.5	1.05
KALM	Kalmiopsis Wilderness Area	15.5	15.1	11.97	9.4	6.3	6.1	5.9
STAR	Strawberry Mountain and Eagle Cap Wilderness Areas	18.6	17.5	11.19	8.9	4.5	4.1	2.79
HECA	Hells Canyon Wilderness Area	18.6	16.6	12.33	8.3	5.5	4.7	4.00

2.1.1 Status of implementation of control measures included in the original regional haze SIP

The Regional Haze Rule requires 5-year progress reports to contain, "a description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State." [40 CFR.308 (g)(1)].

In Oregon's first Regional Haze Plan, submitted in 2010, DEQ determined that five sources were subject to Best Achievable Retrofit Technology. They were: the Portland General Electric plant in Boardman PGE Beaver Power Plant, Georgia Pacific Wauna Mill, International Paper in Springfield, and the Amalgamated Sugar Plant in Nyssa. DEQ amended the PGE Boardman Title V permit to include conditions requiring BART control installation and to permanently cease burning coal in the main boiler by December 31, 2020. The remaining four facilities opted for one or more federally enforceable permit limits to reduce visibility impacts below 0.5 dv (the evaluative method DEQ employed for Round 1 regional haze analysis).

In the 2017 5-year Progress Report, DEQ reported that in 2011, PGE Boardman installed low NO_x burners with a modified over-fire air system and in 2014, BART SO_2 controls, consisting of a dry sorbent injection (DSI) system. PGE Boardman was meeting BART NO_x and SO_2 emission limitations. A second BART SO_2 emission limit was required in 2018 and the coal-fired facility closed permanently in December 2020.

The PGE Beaver facility requested daily fuel oil limits for facility turbines based upon the daily quantity and the sulfur content of the fuel oil combusted, as well as a requirement that all future shipments of oil contain no more than 0.0015% sulfur (i.e. Ultra Low Sulfur Diesel). An equation was developed to determine a daily fuel oil quantity limit that is tied to the sulfur content of the fuel, so as not to exceed the visibility impact threshold level of 0.5 dv. The PGE Beaver facility still operates under these permit conditions. DEQ's Round 2 regional haze screening and four factor analysis processes included this facility.

The Amalgamated Sugar facility was shut down at the time of the 2017 5-year Progress Report. DEQ's BART rules in 340-223-0040(3) (now repealed) had specified that this facility must either modify its permit by adopting a federally enforceable permit limit or be subject to BART before resuming operation. The facility closed permanently in September 2016 and have no active permit.

DEQ renewed the Georgia Pacific Wauna mill Title V permit in June 2009, which incorporated FEPL requirements, revised the permit in December 2010 to reflect elimination of a non-condensable gas incinerator and a major BART-eligible emission unit, and revised the permit in March 2019 to incorporate a new wood chipping operation. The facility still operates under these permit conditions. In the 2017 5-year Progress Report, DEQ reported that the use of fuel oil in the power boiler had been permanently discontinued and the maximum pulp production rate was limited to 1,350 tons per day after completion of the non-condensable gas project. The facility still operates under these constraints. DEQ's Round 2 regional haze screening and four factor analysis processes included this facility.

The Lane Regional Air Protection Agency modified the International Paper Springfield Title V permit in April 2009 to incorporate FEPL requirements. Requirements included replacing the steam and mud drums on No. 4 Recovery by the end of 2010 and not burning No.6 Fuel Oil in the Power Boiler when the No.3 Recovery Furnace was operating. The permittee would demonstrate compliance through a formula, emission factors and continuous emissions monitoring data. The facility still operates under these conditions and reports compliance with the BART daily average limit in each monthly air report submitted to LRAPA. DEQ's Round 2 regional haze screening and four factor analysis processes included this facility.

In the 2017 5-year Progress Report also provided the implementation status of Oregon Smoke Management Plan. In 2013, DEQ evaluated the contribution of prescribed fire to Oregon Class I areas, showing impacts in at least two areas – Kalmiopsis Wilderness and Crater Lake National Park. The Oregon Department of Forestry modified the Smoke Management Plan to incorporate practices that DEQ recommended from that study, including:

- visibility evaluations of October – November prescribed burns within 50 miles of either area;
- assessing potential for a direct plume impact at ground level in Class I areas;
- employing additional emission reduction techniques in the event of an impact;
- rapid mop-up of residual smoke when necessary to prevent intrusion; and
- post-burn reporting and evaluation of smoke intrusion.

These changes were submitted to EPA in June 2014 as a revision to the State Implementation Plan but not approved into the SIP until May 2021 along with 2019 revisions to the Smoke Management Plan. The 2019 revisions were the most comprehensive in some time, including new air quality criteria for smoke intrusions and smoke incidents.

2.1.2 Emission Reductions Achieved by SIP Measures

The Regional Haze Rule requires 5-year progress reports to contain, "a summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (g)(1)." [40 CFR.308 (g)(2)]. The 2017 5-year Progress Report reported emission reductions measured or modeled for each of the Round 1 sources that reduced emissions through BART or FEPL. For the purposes of the 5-year progress report within this Round 2 Regional Haze Plan, DEQ reports emission reductions by citing actual emissions as reported to the 2017 National Emissions Inventory for the Round 1 facilities still actively operating in 2017. In Table 2-2, DEQ summarizes actual 2017 emissions for the four facilities regulated through Round 1 Regional Haze and still operating in 2017.

Table 2-2: Actual 2017 emissions for sources reducing emissions in Round 1 Regional Haze

Round 1 Source	NO_x (tons/year)	PM10 (tons/year)	SO_2 (tons/year)
PGE Boardman	1,768.12	387.75	3,297.87
PGE Beaver	359.22	62.19	9.85
Georgia Pacific Wauna	1,037.66	775.80	539.82
International Paper	724.02	181.39	67.64

DEQ reports on emission reductions attributable to the Smoke Management Plan with the same metrics reported in the 2017 5-year Progress Report. The first metric is acres of treated public and private forestland where land managers used alternatives to burning or employed emission reduction techniques instead of using prescribed fire. Alternatives to burning include biomass removal, scattering material, chipping, crushing, firewood removal, non-treatment, other techniques to reduce fire hazard and/or creating planting spots. Emission reduction techniques include piling clean piles instead of broadcast or underburning, use of rapid ignition techniques, covering piles to keep dry, other techniques to reduce particulate and gaseous emissions. Table

2-3 shows the number of alternatively treated acres in 2018, from the 2018 Oregon Smoke Management Annual Report[8].

The second metric is the number of acres burned in 2014 through 2018 and the number of intrusions into one or more of Smoke Sensitive Receptor Areas. Table 2-4 displays this information. The average number of intrusions per year is 12.2 and represents a small percentage of overall prescribed burning activity.

Table 2-3: Acres treated with prescribed burning and alternatives in 2018.

Treatment	Total Statewide Acres
Prescribed Burning	185,702
Alternatives to Burning	45
Emission Reduction Techniques	136,478

Table 2-4: Prescribed Forestry Burns and Intrusions 2014 - 2018

Year	Total No. Units	No. Units Burned	Acres Burned	Number Intrusions	Percentage of Units with Intrusion
2014	4,095	3,443	208,593	13	0.38%
2015	3,601	3,076	179,613	9	0.29%
2016	3,484	2,868	181,800	11	0.38%
2017	3,597	2,849	159,624	10	0.35%
2018	4,307	3,382	185,702	18	0.53%

In Table 2-5, DEQ provides cross references to sections in this Round 2 Plan that address the three elements required under 40 CFR.308 (g)(3), (g)(4), and (g)(5).

Table 2-5: Five-year progress report required elements cross references to Regional Haze Plan sections.

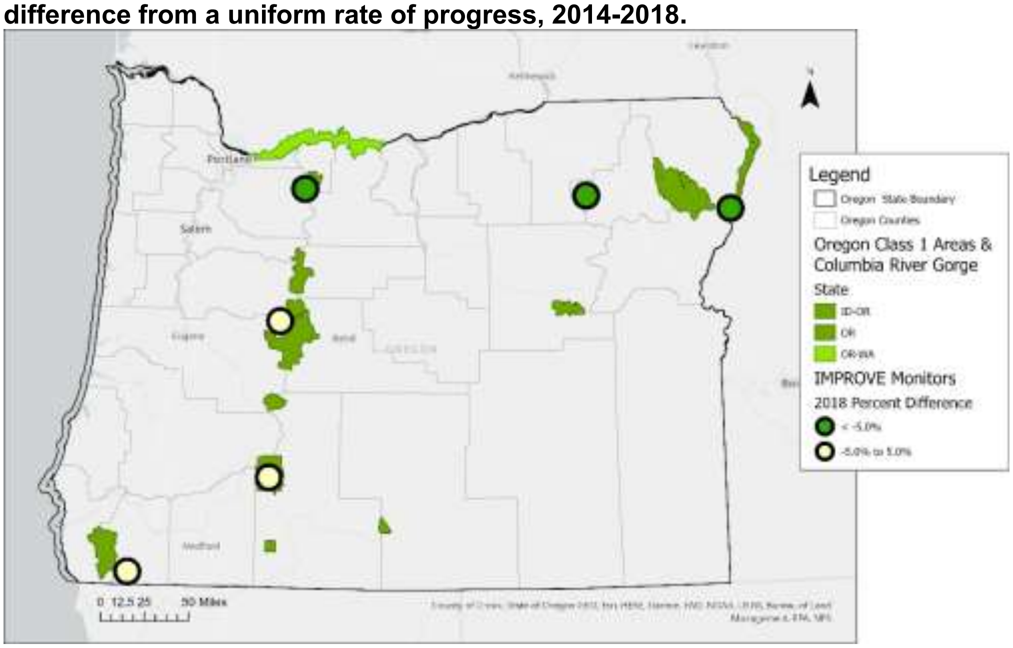
CFR Citation	Progress Report Element	Round 2 Plan Section
40 CFR 51.308 (g)(3)	"For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values" for the period since the most recent progress report	Sections 2.1 and 2.2
40 CFR 51.308 (g)(4)	"An analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the State."	Section 2.3
40 CFR 51.308 (g)(5)	"An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan…"	Section 2.4 and 2.5

[8] https://www.oregon.gov/odf/Documents/fire/SMR2018.pdf

2.1. Most Impaired Days

Based on the EPA's data released in September 2019,[9] and corrected data released in June 2020,[10] Figure 2-1Figure 2-1 shows the visibility at the 6 IMPROVE monitors that cover the 12 Class 1 Areas in Oregon for the period from 2014-2018, for the most impaired days, as a percent difference from a uniform rate of progress in 2018.

Figure 2-1: Visibility on most impaired days at the six Oregon IMPROVE monitors as a percent difference from a uniform rate of progress, 2014-2018.



In 2018, three monitors in light yellow (KALM1, CRLA1, and THSI1) in the southern part of the state are within 5 percent above or below a uniform rate of progress, or "on the glidepath." In 2018, all of these monitors are meeting the URP, but just barely. These three monitors cover 8 Class 1 Areas (Kalmiopsis Wilderness, Crater Lake National Park, Diamond Peak Wilderness, Mountain Lakes Wilderness, Gearhart Mountain Wilderness, Three Sisters Wilderness, Mount Jefferson Wilderness, and Mount Washington Wilderness).

The other three monitors in green (MOHO1, STAR1, and HECA1), are greater than 5% below the URP, or "below the glidepath." They cover 4 Class 1 Areas (Mount Hood Wilderness, Strawberry Mountain Wilderness, Eagle Cap Wilderness, and Hells Canyon Wilderness).

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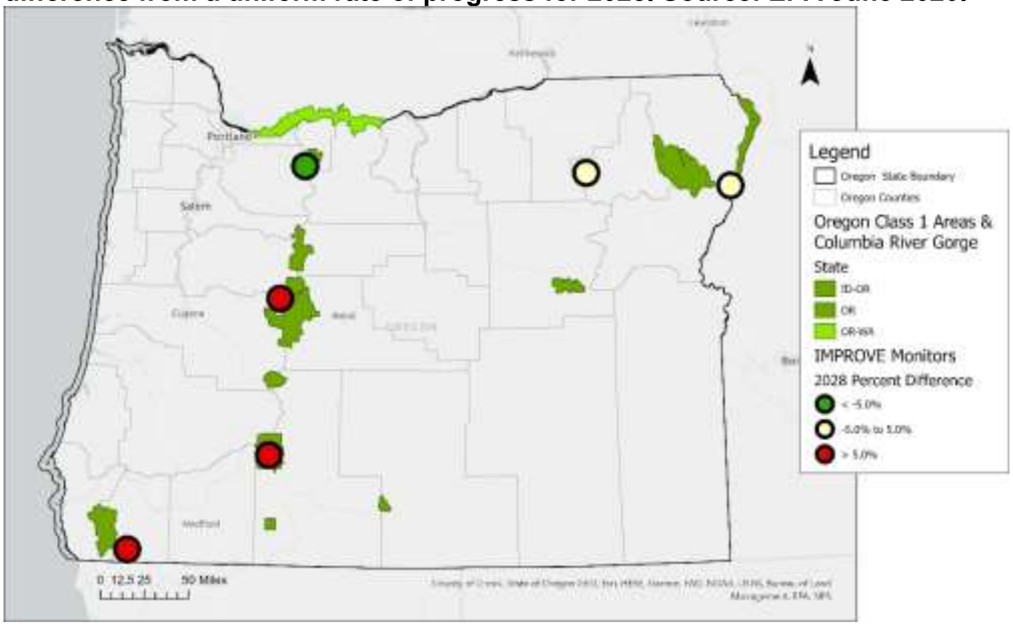
[9] U.S. EPA, 2019, *supra.*

[10] U.S. EPA. 2020. *Technical addendum including updated visibility data through 2018 for the memo titled "Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program."* https://www.epa.gov/sites/production/files/2020-06/documents/memo_data_for_regional_haze_technical_addendum.pdf (Accessed 12/22/20)

Figure 2-2 shows the 2028 projected visibility at the 6 IMPROVE monitors that cover the 12 Class 1 areas in Oregon, for the most impaired days, as a percent difference from the 2028 URP.

Figure 2-2: Projected visibility on most impaired days at the six IMPROVE monitors as a percent difference from a uniform rate of progress for 2028. Source: EPA June 2020.



Based on EPA's "on the books" 2028 projections (for Oregon, representing regulations in place as of May 2020), if no further reductions are realized, the eight Class 1 Areas covered by the Three Sisters, Crater Lake, and Kalmiopsis monitors will be more than 5% above the glidepath and no longer meeting a uniform rate of progress necessary to achieve natural conditions by 2064 (shown in red in **Error! Reference source not found.**). In addition, the STAR1 monitor and the HECA1 monitor in the eastern part of the state will be within 5% of URP (the two dots in light yellow in the map below). Mount Hood Wilderness is projected to be below the glidepath.

Based on the composition of regional haze forming pollutants at the IMPROVE monitors, the majority of U.S. anthropogenic contribution to regional haze in Oregon Class 1 Areas is from ammonium nitrate. This varies seasonally and by monitor. At some monitors, ammonium sulfate is a large contributor to regional haze formation, but that contribution seems to be significantly from international anthropogenic sources and is projected to decrease by 77%[11] as new standards for international marine shipping fuels take effect in 2020. In addition, sulfate performance in the regional model used by EPA over predicted sulfates and nitrates in the Northwest region, where Oregon is located.[12] A more detailed review of the EPA and WRAP 2028 modeled data is presented in more detail in Sections 2.4 and 2.5.

Based on EPA's published and corrected data for the IMPROVE monitoring network, Table 2-6 shows the monitoring information available for each of the 12 Oregon Class 1 areas on most impaired days:

- The baseline period of 2000-2004
- The projected natural conditions in 2064
- The observed visibility impairment in deciviews for current visibility (2014-2018)
- The calculated uniform rate of progress for 2018 (on the glidepath)

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[11] International Marine Organization. 2020. *A Breath of Fresh Air.* https://wwwcdn.imo.org/localresources/en/MediaCentre/HotTopics/Documents/Sulphur%202020%20infographic%202%20page.pdf (Accessed 1/20/21)

[12] U.S. EPA. 2019. *Op. cit.* p. 13.

- The difference in deciviews (observed minus expected) of the observed value from the URP for 2018
- The percent difference (observed minus expected) of the observed value from the URP for 2018
- The difference of 2018 observed visibility impairment to the calculated 2064 natural conditions (NC)
- The projected visibility impairment in deciviews for 2028
- The calculated URP 2028 (on the glidepath)
- The difference between the projected 2028 value and the 2028 URP value on the glidepath
- The percent difference (observed minus expected) of the 2028 projected value to the URP.

Table 2-6: Visibility in deciviews on most impaired days for Oregon's 12 Class 1 areas, showing baseline, current visibility (2014-2018), natural conditions, and comparisons to 2018 and 2028 glidepath (URP) values. [13]

CLASS 1 AREA NAME	IMPROVE SITE	2064 NC (DV)	2000-2004 OBS (DV)	OBS 2008-2012	2014-2018 OBS (DV)	2018 URP (DV)	2018 DIFF TO URP (DV)	2018 PCT DIFF URP	2018 OBS DIFF NC (DV)	2028 OTB PROJ (DV)	2028 URP (DV)	2028 DIFF (DV)	2028 PCT DIFF
Diamond Peak Wilderness	CRLA1	5.16	9.36	9.0	7.98	8.38	-0.40	-5%	2.82	8.09	7.7	0.39	5%
Gearhart Mountain Wilderness	CRLA1	5.16	9.36	9.0	7.98	8.38	-0.40	-5%	2.82	8.09	7.7	0.39	5%
Mountain Lakes Wilderness	CRLA1	5.16	9.36	9.0	7.98	8.38	-0.40	-5%	2.82	8.09	7.7	0.39	5%
Crater Lake NP	CRLA1	5.16	9.36	9.0	7.98	8.38	-0.40	-5%	2.82	8.09	7.7	0.39	5%
Hells Canyon Wilderness	HECA1	6.57	16.51	12.3	12.33	14.19	-1.86	-13%	9.94	12.21	12.53	-0.32	-3%
Kalmiopsis Wilderness	KALM1	7.78	13.34	12.8	11.97	12.04	-0.07	-1%	5.56	11.74	11.13	0.61	5%
Mount Hood Wilderness	MOHO1	6.59	12.1	10.3	9.27	10.81	-1.54	-14%	5.51	8.95	9.9	-0.95	-10%
Strawberry Mountain Wilderness	STAR1	6.58	14.53	11.7	11.19	12.68	-1.49	-12%	7.95	10.88	11.35	-0.47	-4%
Eagle Cap Wilderness	STAR1	6.58	14.53	11.7	11.19	12.68	-1.49	-12%	7.95	10.88	11.35	-0.47	-4%
Three Sisters Wilderness	THSI1	7.3	12.8	11.8	11.46	11.52	-0.06	0%	5.5	11.26	10.6	0.66	6%
Mount Jefferson Wilderness	THSI1	7.3	12.8	11.8	11.46	11.52	-0.06	0%	5.5	11.26	10.6	0.66	6%
Mount Washington Wilderness	THSI1	7.3	12.8	11.8	11.46	11.52	-0.06	0%	5.5	11.26	10.6	0.66	6%

[13] The data in this table are drawn from “Availability of Modeling Data and Associated Technical Support Document for the EPA’s Updated 2028 Visibility Air Quality Modeling” (EPA 2019). https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling; with corrected data as applicable from the June 2020 EPA Memo, “Technical addendum including updated visibility data through 2018 for the memo titled ‘Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.’” https://www.epa.gov/sites/production/files/2020-06/documents/memo_data_for_regional_haze_technical_addendum.pdf (Accessed 1/20/21)

2.2. Clearest Days

Table 2-7 presents the following data for clearest days for the 12 Class 1 areas in Oregon:

- The baseline period of 2000-2004
- The projected natural conditions in 2064
- The observed visibility impairment in deciviews for current visibility (2014-2018)
- The calculated URP for 2018 (on the glidepath)
- The difference (observed minus expected) of the observed value from the URP for 2018
- The difference of 2018 observed visibility impairment to the calculated 2064 NC
- The calculated URP for 2028 (on the glidepath)
- The difference between the projected 2028 value and the 2018 URP value on the glidepath
- The percent difference (observed minus expected) of the 2018 observed value to the URP.

Results listed in Table 2-7 indicate continued improvement in the clearest days at all of the IMPROVE monitors and Class 1 areas in Oregon.

Table 2-7. Visibility in deciviews on clearest days for Oregon's 12 Class 1 areas, showing baseline, current visibility (2014-2018), natural conditions, and comparisons to 2018 and 2028 glidepath (URP) values. [14]

CIA_NAME	IPROVE SITE	2064 NC	OBS 2000-2004	OBS 2008-2012	OBS 2014-2018	2018 URP	2018 OBS DIFF TO URP	2018 PCT DIFF	2018 DIFF FROM NC	2028 URP	2028 DIFF FR 2018 OBS
Diamond Peak Wilderness	CRLA1	0.1	1.69	1.4	1.05	1.32	-0.27	-20%	0.95	1.05	0.00
Gearhart Mountain Wilderness	CRLA1	0.1	1.69	1.4	1.05	1.32	-0.27	-20%	0.95	1.05	0.00
Mountain Lakes Wilderness	CRLA1	0.1	1.69	1.4	1.05	1.32	-0.27	-20%	0.95	1.05	0.00
Crater Lake NP	CRLA1	0.1	1.69	1.4	1.05	1.32	-0.27	-20%	0.95	1.05	0.00
Hells Canyon Wilderness	HECA1	2.52	5.50	4.2	4.00	4.80	-0.80	-17%	1.48	4.31	-0.31
Kalmiopsis Wilderness	KALM1	3.7	6.27	6.2	5.9	5.67	0.23	4%	2.2	5.24	0.66
Mount Hood Wilderness	MOHO1	0.88	2.17	1.4	1.39	1.87	-0.48	-26%	0.51	1.65	-0.26
Strawberry Mountain Wilderness	STAR1	1.48	4.49	3.1	2.79	3.79	-1.00	-26%	1.31	3.29	-0.50
Eagle Cap Wilderness	STAR1	1.48	4.49	3.1	2.79	3.79	-1.00	-26%	1.31	3.29	-0.50
Three Sisters Wilderness	THSI1	1.86	3.04	2.8	2.61	2.76	-0.15	-6%	0.75	2.57	0.04
Mount Jefferson Wilderness	THSI1	1.86	3.04	2.8	2.61	2.76	-0.15	-6%	0.75	2.57	0.04
Mount Washington Wilderness	THSI1	1.86	3.04	2.8	2.61	2.76	-0.15	-6%	0.75	2.57	0.04

[14] The data in this table are drawn from "Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling" (EPA 2019). https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling; with corrected data as applicable from the June 2020 EPA Memo, "Technical addendum including updated visibility data through 2018 for the memo titled 'Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.'" https://www.epa.gov/sites/production/files/2020-06/documents/memo_data_for_regional_haze_technical_addendum.pdf (Accessed 1/20/21)

2.3. Emissions Inventory Analysis

WRAP used data from the 2017 National Emissions Inventory to create statewide emissions inventories for all western states participating in Regional Haze Round 2. The inventory was used to model current and projected emission impacts on Class 1 area visibility. DEQ reviewed and provided corrections to the 2017 NEI data that WRAP incorporated into Oregon's inventory. DEQ commits to periodic updates to Oregon's statewide emissions inventory, at a minimum complying with requirements under EPA's Air Emission Reporting Requirements rule.

DEQ analyzed actual emissions (tons per year) from various NEI categories and sectors that contribute to Class 1 area visibility impairment. For this analysis, in order to focus on US anthropogenic emission sources or sectors, WRAP removed emissions for biogenic, wildfire, and dust emission sources for the state. Oregon anthropogenic emission sources in this inventory include, but are not limited to:

- Point sources that are federal or state air permitted facilities and airports (not necessarily permitted by Oregon DEQ). Permitted emissions activities mainly entail fuel combustion and process emissions from pulp and paper, wood products manufacturing, electricity generation and gas transmission, metal processing and fabrication, landfills, etc. in Oregon.
- Nonpoint and event source activities resulting in emissions from fuel combustion, agriculture, fugitive dust, marine shipping, oil and gas, prescribed fires, and railroads.
- Mobile sources such as nonroad vehicles (e.g. construction, agriculture, lawn and garden, recreational equipment) and onroad vehicles (e.g. commercial trucks, passenger cars and trucks).

Regional haze forming pollutants from US anthropogenic emission sources are largely composed of nitrogen oxide (NO_x) particulate matter with diameter of 2.5 and 10 microns (PM2.5 and PM10), sulfur dioxide (SO_2), and ammonia (NH_3). DEQ reviewed total regional haze forming pollutant emissions at the county level, shown in Table 2-8. Annual emissions are greatest in Multnomah County, which includes urban Portland, and in the higher-elevations of central Oregon (Deschutes County), which includes the city of Bend. The Interstate-5 corridor south of Portland connects Lane and Marion Counties through the Willamette Valley, and includes the cities of Eugene and Salem, respectively. The Portland metropolitan area includes the urbanized and suburbanized areas of Washington and Clackamas Counties, which also rank among the state's highest producers of regional haze pollutant emissions.

Table 2-8. Regional haze pollutants emissions in tons/year by county, U.S. Anthropogenic, 2017. Source: 2017 National Emission Inventory.

County	NO_x	PM10-PRI	SO_2	Total
Multnomah	17155	20428	840	38422
Deschutes	4140	33380	88	37608
Lane	9690	23280	513	33482
Washington	8466	21630	345	30441
Clackamas	7667	21786	263	29716
Marion	7820	18622	210	26652
Klamath	3815	20875	297	24987
Douglas	6264	17610	545	24419
Umatilla	3922	18430	85	22437
Linn	5317	13763	261	19341
Jackson	5064	11854	178	17096
Malheur	1456	14870	212	16538
Morrow	3145	8529	3340	15014
Clatsop	4587	6745	669	12001
Wasco	1949	9722	114	11785
Yamhill	2143	9084	157	11384
Coos	1933	8756	105	10794
Polk	1469	9190	60	10719
Jefferson	881	9643	57	10580
Lincoln	2207	7327	69	9603
Harney	604	8472	78	9154
Lake	757	8026	99	8882
Crook	719	8082	58	8859
Josephine	2163	6370	46	8579
Baker	2605	5816	81	8502
Tillamook	1189	7149	100	8439
Union	1897	5899	48	7844
Benton	1511	5588	58	7157
Columbia	2790	4248	60	7098
Curry	763	5275	23	6061
Sherman	539	5398	6	5943
Grant	515	5147	101	5762
Gilliam	1023	2977	59	4059
Hood River	1343	2416	16	3775
Wallowa	284	3098	9	3391
Wheeler	117	1596	23	1736

Table 2-9 through Table 2-11 show the major source sectors for particulate matter, nitrogen oxides, and sulfur dioxide emissions after wildfire, biogenics, and dust emission sources(so-called “natural sources”) were removed from the 2017 NEI. DEQ found that:

- For particulate matter, major source sectors are prescribed fire and agriculture, comprising 77% of the anthropogenic inventory (Table 2-9)
- Statewide, the NO_x emissions are primarily from mobile sources, at about 80% of the inventory, with another 13% of the inventory coming from fuel combustion (Table 2-10).
- The 2017 SO_2 inventory is largely overwhelmed by PGE Boardman’s coal-fired power plant in Morrow County. With the closing of the plant in October 2020, those emissions have largely been eliminated, and the remainder of the emissions come from fuel combustion and prescribed fires (Table 2-11).

Table 2-9. Major sectors contributing to PM10 emissions in tons/year by county, US Anthropogenic, 2017. Source: 2017 National Emissions Inventory.

County	Ag -PM10	Fires - PM10	Fuel Comb - PM10	Ind -PM10	Mobile - PM10	Total
Umatilla	8601	380	311	50	174	9515
Douglas	945	6047	718	588	208	8507
Klamath	2387	3718	414	184	152	6855
Lane	830	3196	1089	670	441	6238
Morrow	4978	87	461	18	47	5593
Malheur	4463	161	84	41	71	4821
Harney	3466	980	32	0	24	4503
Lake	2438	1385	38	64	31	3956
Marion	905	1447	663	177	469	3661
Wasco	1871	1417	80	15	75	3458
Clackamas	558	907	1062	252	563	3342
Multnomah	98	207	1247	475	1140	3208
Baker	2085	530	79	432	70	3196
Linn	750	1161	419	541	238	3110
Sherman	2940	15	13	0	21	2989
Washington	401	473	1124	136	646	2780
Jackson	551	774	643	321	282	2571
Grant	1030	1424	58	0	23	2535
Gilliam	2178	32	33	0	32	2275
Union	1684	292	109	64	64	2213
Clatsop	113	868	296	793	124	2193
Yamhill	572	864	269	163	124	1992
Tillamook	370	1295	157	77	54	1953
Crook	1038	660	93	22	36	1849
Coos	335	968	225	201	87	1816
Deschutes	388	184	699	208	253	1732
Polk	590	508	212	13	81	1403
Jefferson	618	630	96	16	41	1402
Wallowa	1224	67	50	0	23	1364
Lincoln	82	536	215	253	69	1155
Benton	257	265	239	86	102	948
Columbia	245	53	234	219	99	850
Josephine	123	93	297	34	119	671
Wheeler	373	276	10	0	4	663
Curry	81	150	143	95	41	510
Hood River	60	3	86	0	63	212
Total	49629	32056	11995	6212	6089	106040

Table 2-10. Major sectors contributing to NO_x emissions in tons/year by county, US Anthropogenic, 2017. Source: 2017 National Emissions Inventory.

County	Fires-NO_x	FuelComb-NO_x	Industrial-NO_x	Mobile-NO_x	Total
Multnomah	18	1998	603	14535	17155
Lane	292	1227	812	7359	9690
Washington	53	1530		6883	8466
Marion	148	578		7094	7820
Clackamas	90	1170	12	6395	7667
Douglas	584	1445	65	4169	6264
Linn	112	551	427	4227	5317
Jackson	81	863	76	4044	5064
Clatsop	76	582	603	3326	4587
Deschutes	24	392		3724	4140
Umatilla	78	452	1	3392	3922
Klamath	391	474	11	2938	3815
Morrow	16	2099	1	1030	3145
Columbia	5	656	134	1995	2790
Baker	60	198	788	1559	2605
Lincoln	47	542	463	1155	2207
Josephine	13	144	9	1996	2163
Yamhill	94	220	166	1663	2143
Wasco	188	30	7	1724	1949
Coos	87	154	1	1691	1933
Union	38	385	105	1369	1897
Benton	30	154	27	1301	1511
Polk	63	113		1293	1469
Malheur	24	68	44	1320	1456
Hood River	0	55		1287	1343
Tillamook	109	114	1	965	1189
Gilliam	8	176		840	1023
Jefferson	92	37		752	881
Curry	18	81	1	664	763
Lake	153	21		583	757
Crook	80	42	1	596	719
Harney	144	9		450	604
Sherman	5	39		496	539
Grant	155	76		284	515
Wallowa	9	14		261	284
Wheeler	45	2		70	117
Total	3,426	16,692	4,358	93,427	117,907

Table 2-11. Major sectors contributing to SO_2 emissions in tons/year by county, US Anthropogenic, 2017. Source: 2017 National Emissions Inventory.

County	Fires	Fuel Comb	Industrial Processes	Mobile	Total
Morrow	7	3330	1	2	3340
Multnomah	13	334	181	310	840
Clatsop	53	46	514	56	669
Douglas	384	142	4	13	545
Lane	198	165	111	39	513
Washington	31	279		34	345
Klamath	241	38	1	18	297
Clackamas	58	176	1	28	263
Linn	72	100	75	13	261
Malheur	11	15	182	4	212
Marion	86	94		29	210
Jackson	51	99	4	24	178
Yamhill	56	57	36	7	157
Wasco	104	5	1	4	114
Coos	60	34	0	11	105
Grant	95	5		1	101
Tillamook	78	18	1	3	100
Lake	93	4		1	99
Deschutes	13	53		22	88
Umatilla	31	42	1	10	85
Baker	36	8	33	4	81
Harney	75	2		1	78
Lincoln	33	17	12	7	69
Columbia	3	28	7	23	60
Polk	35	20		5	60
Gilliam	3	55		2	59
Crook	46	9	1	2	58
Benton	18	34	0	5	58
Jefferson	43	12		2	57
Union	18	25	2	4	48
Josephine	7	29	4	7	46
Curry	10	9	1	3	23
Wheeler	22	0		0	23
Hood River	0	13		4	16
Wallowa	5	3		1	9
Sherman	2	3		1	6
Total	2090	5304	1175	702	9273

2.4 Pollutant Components of Visibility Impairment

Identification of the significant components contributing to visibility impairment in Class 1 areas is important for 1) determining the glidepath to achieving natural conditions by 2064, 2) assessing projections of 2028 conditions against that glidepath (Sec. 2.5.1), 3) identifying the source categories that are majorly responsible for the impairment (2.5.2), 4) helping to identify sources for the Four Factor analysis (Sec. 3.5) and 5) informing Oregon's long-term strategy to control emissions and achieve natural conditions in Class 1 areas (Sec. 4).

DEQ first examined the IMPROVE monitoring data from the WRAP Technical Support System website for the period 2000 to 2018. The data for 2000-2004 sets the baseline. The slope of the glidepath, or URP, is based on two endpoints: the 2000 – 2004 baseline and the 2064 Natural Conditions. The data from 2000 to 2018 shows the changes in extinction over that period. **Error! Reference source not found.** to **Error! Reference source not found.** show the measured extinctions at the IMPROVE sites in Oregon. Although sources in Oregon influence extinction at IMPROVE sites in Washington and California, notably MORA (Mt. Rainier, WA), WHPA (White Pass, WA), REDW (Redwoods, CA), and LABE (Lava Beds, CA), their impacts are lower than for Oregon sites, and they are not shown in the figures below. The extinctions are based on monitoring data only; this information does not identify source categories contributing to extinction.

For the eastern Oregon IMPROVE sites (HECA and STAR), there is a noticeable reduction in extinction attributed to ammonium nitrate from 2000-2004 to the 2008-2012 period, but a small increase from 2008-2012 to 2014-2018. For the IMPROVE sites in the Cascades and Kalmiopsis, there is an important reduction in ammonium sulfate, although not as large as ammonium nitrate in the east. The levels of organic mass and elemental carbon, likely from wildfire, prescribed burning, and anthropogenic and biogenic sources of Volatile Organic Compounds vary at all IMPROVE sites from 2000 to 2018, but show no significant trend.

For the following figures, light extinction is expressed as *bext* in inverse million meters (Mm-1). Note that the vertical scale in Mm-1 varies between figures.

Figure 2-3: HECA IMPROVE monitor: Components to visibility impairment.

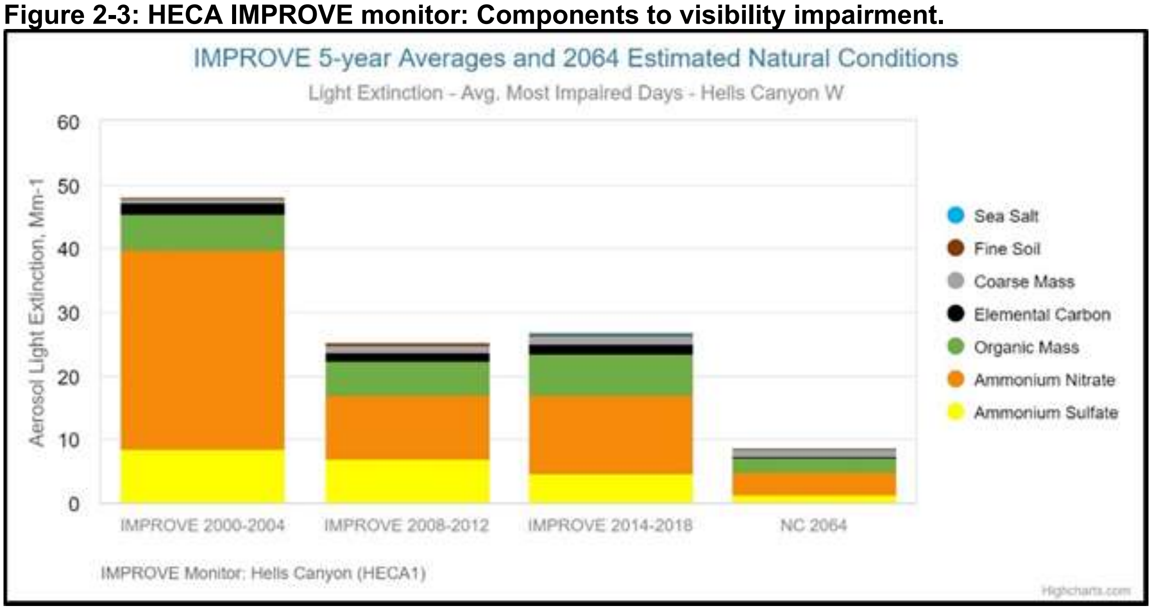


Figure 2-4: STAR IMPROVE monitor: Components to visibility impairment.

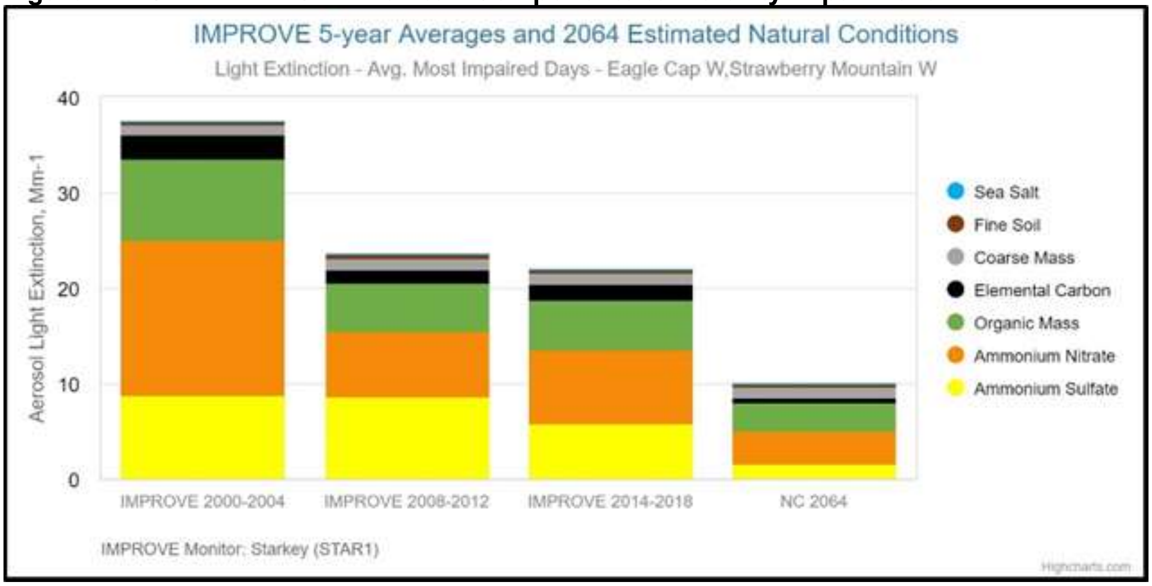


Figure 2-5: MOHO IMPROVE monitor: Components to visibility impairment

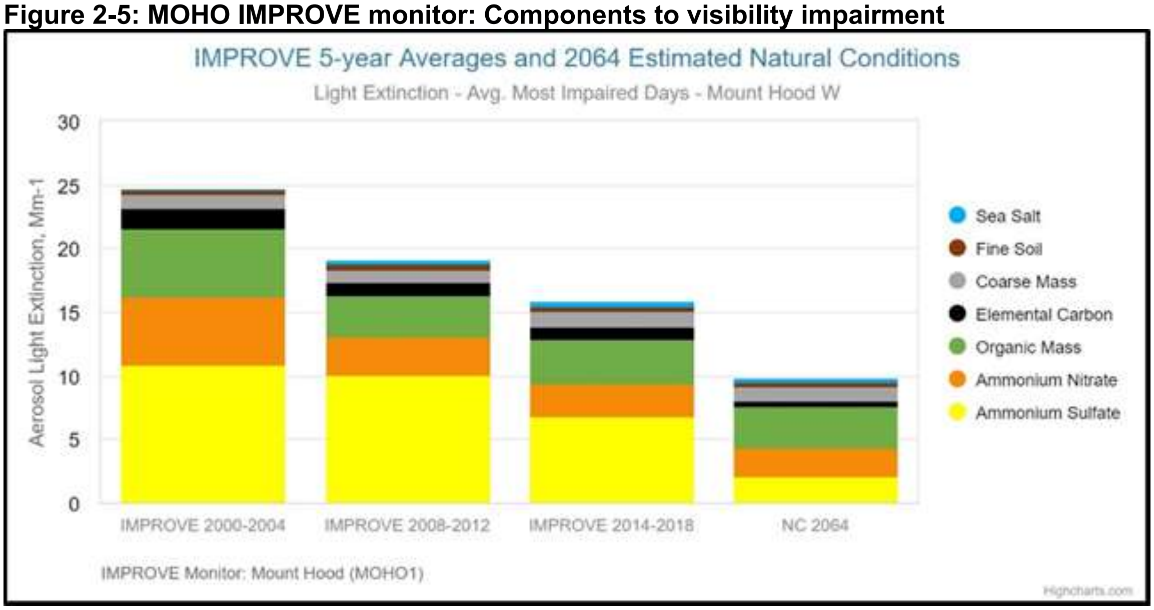


Figure 2-6: THSI IMPROVE monitor: Components to visibility impairment

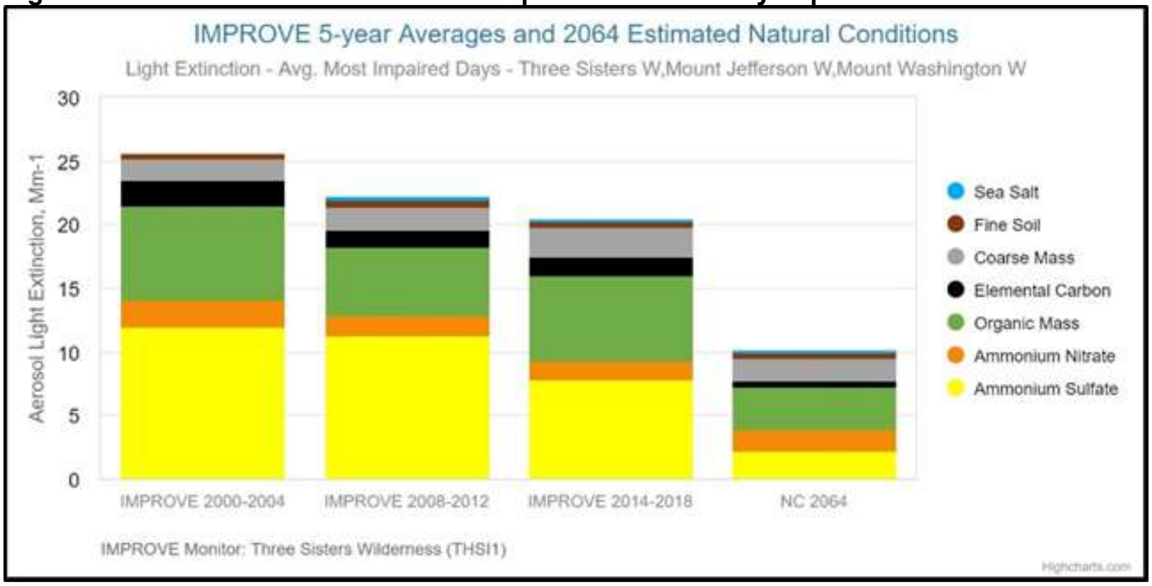


Figure 2-7: CRLA IMPROVE monitor: Components to visibility impairment

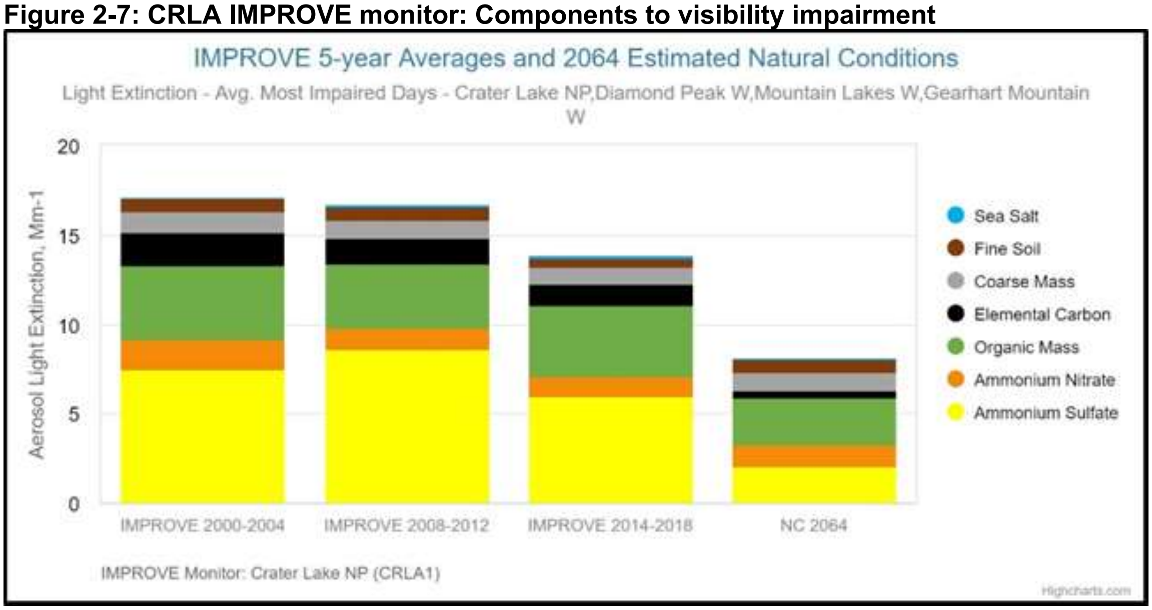
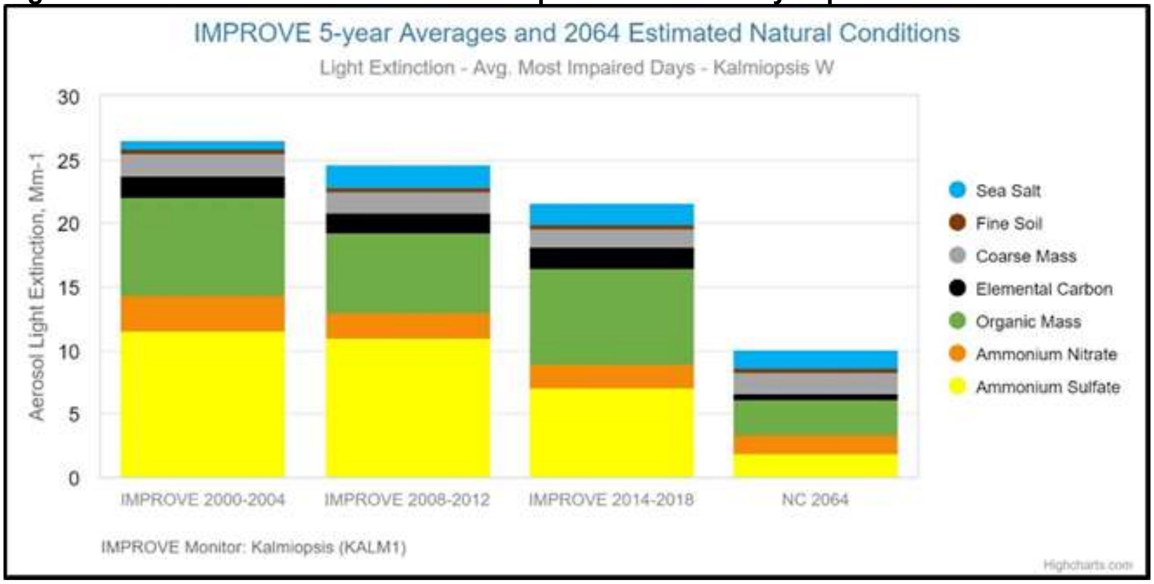


Figure 2-8: KALM IMPROVE monitor: Components to visibility impairment



2.5 Source Apportionment of Visibility Impairment and Weighted Emission Potential

The full suite of WRAP modeling of On the Books emissions includes a high level source apportionment (Region Source Apportionment), low-level source apportionment (State Source-Sector Source Apportionment) and 2028 extinctions based on the projected 2014 extinctions using the EPA Software for the Modeled Attainment Test program. The SMAT projected 2028 extinction is the subject of this section. Both levels of source apportionment modeling assessed extinction for sea salt, soil, coarse mass, organic mass carbon, elemental carbon, ammonium sulfate, and ammonium nitrate.

DEQ examined the WRAP source apportionment modeling and the Weighted Emission Potential analysis to help discern the degree to which different sectors affect visibility in each Class 1 area. The source apportionment and WEP analysis described in this section are based on data from WRAP's TSS website for the Round 2 regional haze analysis. DEQ consulted both the high and low level source apportionment results and WEP analysis to inform the Long-term Strategy (Section 4) and as part of a weight of evidence approach (Section 3.5) before making decisions about facility pollution control requirements. DEQ's pollution control decision methodology is described in Section 3. DEQ based pollution control decisions for particular facilities on source-specific characteristics (e.g. distance to Class 1 area, potential emissions) and a control-specific four-factor analysis.

2.5.1 Estimated future projected emissions

After examining the monitored visibility data, DEQ reviewed the WRAP CAMx modeling results projected to 2028, based on controls that were On The Books as of May 2020, referred to as 2028 OTB emissions.

The initial unadjusted 2028 source apportionment modeling provided information about the relative contributions to extinction from source categories, including US anthropogenic, international, natural, US wildfire, US prescribed wildland fire, and Mexico/Canada wildfire. In general, these model results, not shown here, suggest the three largest contributors to visibility impairment are ammonium nitrate, ammonium sulfate and organic carbon. Important sources of ammonium sulfate are from international and natural emissions and ammonium nitrate comes from mobile and industrial sources. Sources of organic carbon are from US wildfires, US prescribed fires, natural sources, and anthropogenic and biogenic sources of VOCs.

In order to estimate the 2028 RPGs for comparison to the glidepath, WRAP “normalized” the unadjusted 2014 modeled data using the 2014 measured data and the SMAT program. SMAT uses Relative Response Factors to project the measured IMPROVE values for each extinction component, such as ammonium nitrate, to 2028 using the relative changes in the WRAP 2014 and 2028 model results. Simply stated, SMAT takes the actual measured 2014 extinctions as a reference point and projects them to 2028 using the relationship between the 2014 and 2028 modeling. In addition, the 2028 projections included adjustments to certain emission categories. Using the 2014 measured extinction as the reference resolved modeled over predictions in the initial 2014 and 2028 “raw” model results, such as the contributions from wildfire.

Error! Reference source not found. through **Error! Reference source not found.** illustrate the 2014-2018 monitored and 2028 OTB projected modeled extinctions by components for each IMPROVE monitor in Oregon. The 2028 projected values in these bar charts are the result of the SMAT program using RRFs, as noted above, and are shown in comparison to the 2014 – 2018 monitored extinctions. In these figures, light extinction is expressed as *bext* in Mm-1. Abbreviations are: CM = course mass, EC = elemental carbon, OMC = organic mass carbon, AmmNO3 = ammonium nitrate, AmmSO4 = ammonium sulfate.

When comparing the charts for the six IMPROVE sites, note that the vertical scale of light extinction is different for different sites.

Figure 2-9: STAR1 monitor, Projected 2028 visibility using SMAT.

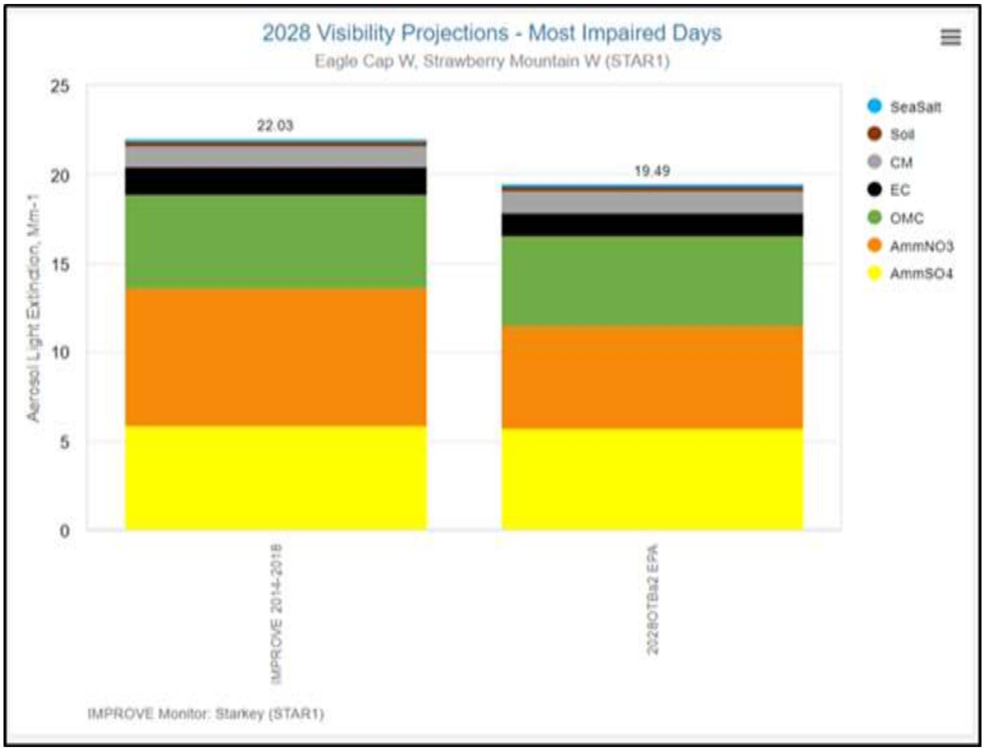


Figure 2-10: HECA monitor, Projected 2028 visibility using SMAT.

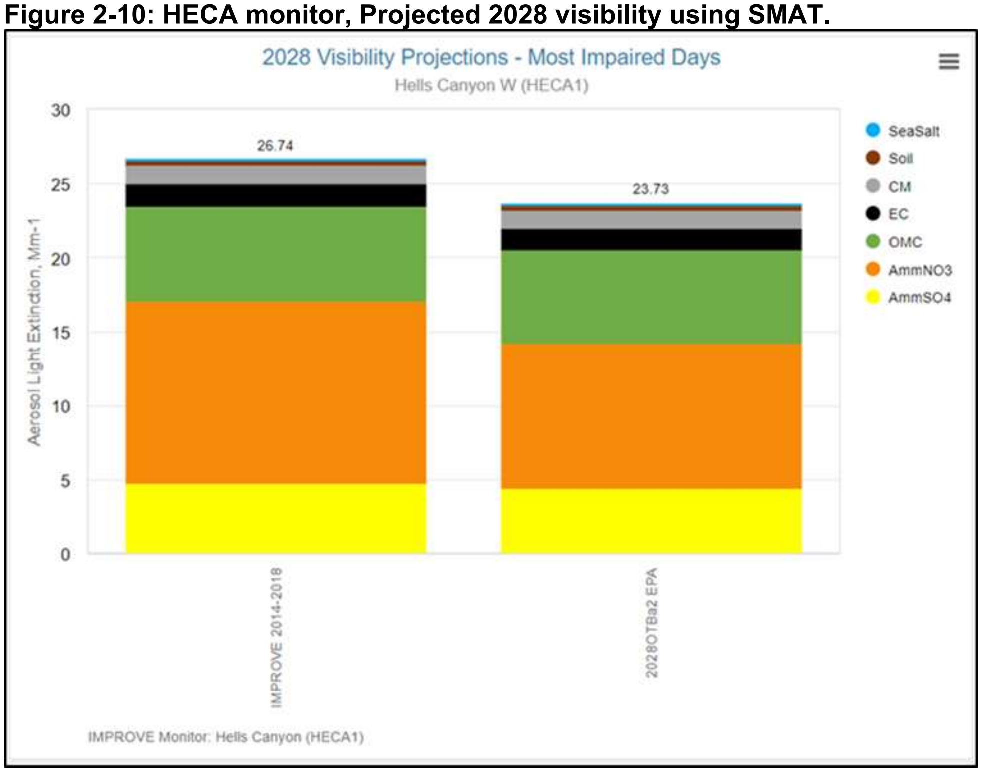


Figure 2-11: THIS monitor, Projected 2028 visibility using SMAT.

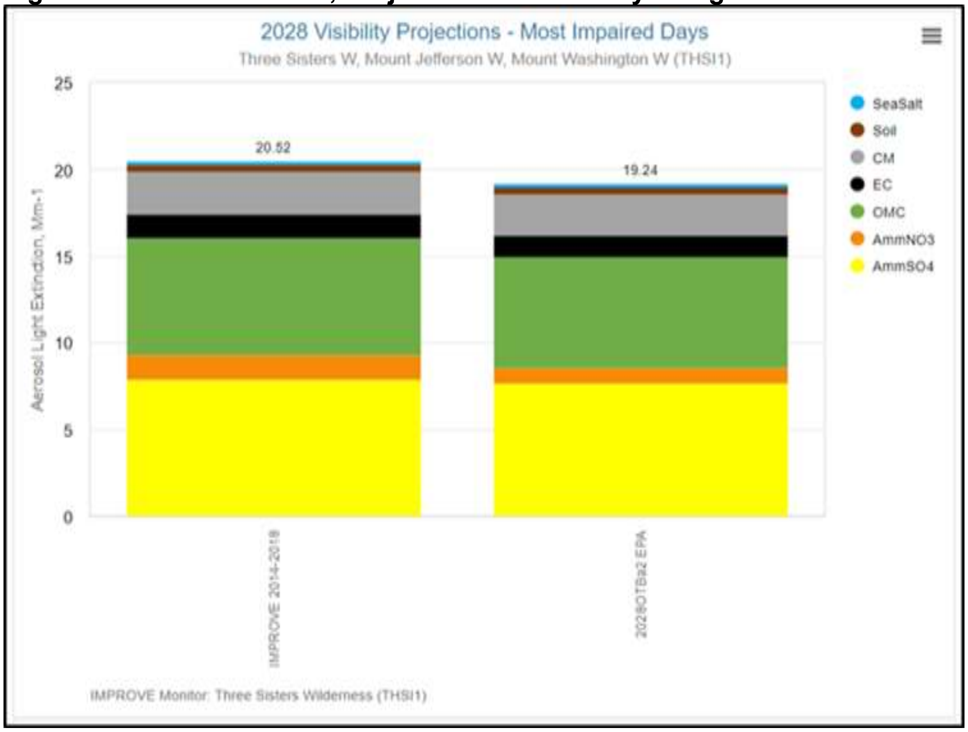


Figure 2-12: MOHO monitor, Projected 2028 visibility using SMAT.

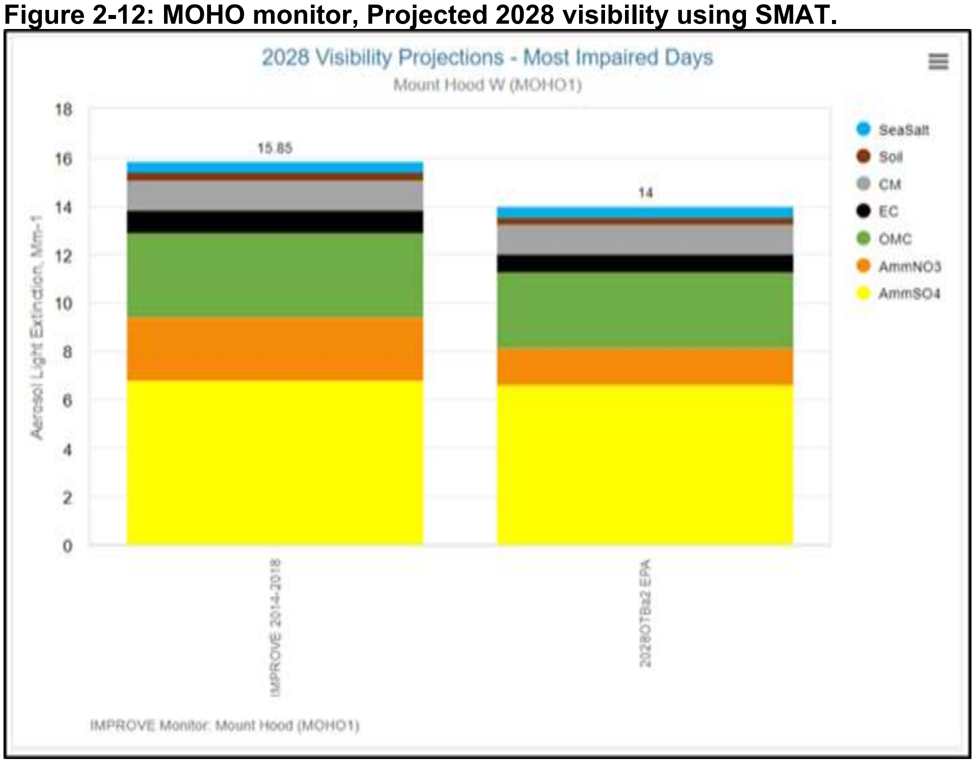


Figure 2-13: CRLA monitor, Projected 2028 visibility using SMAT.

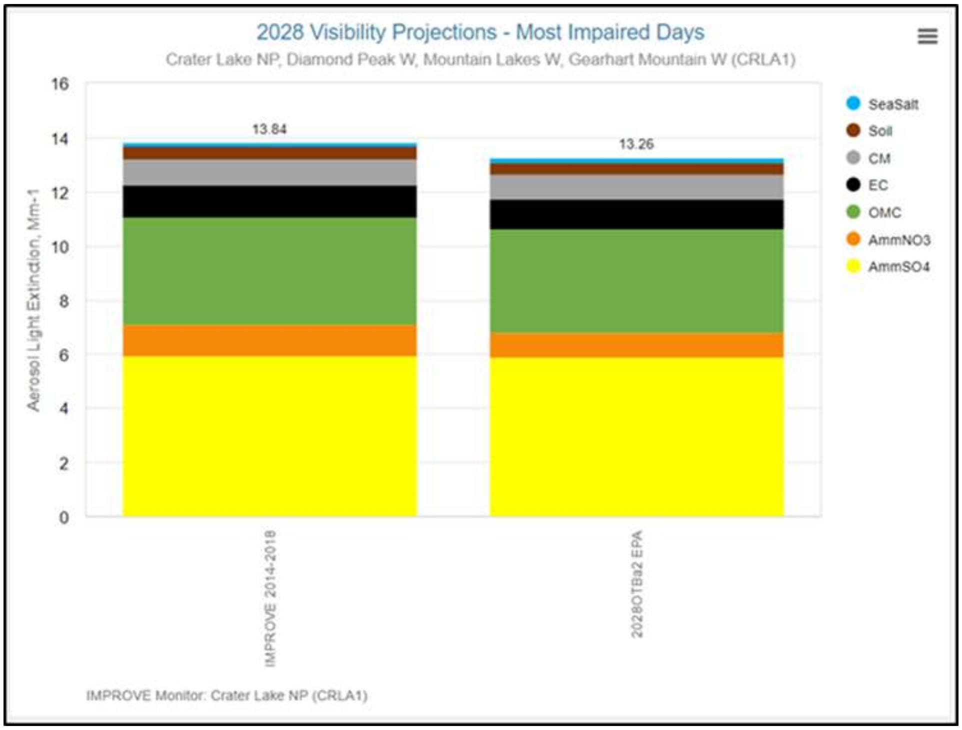
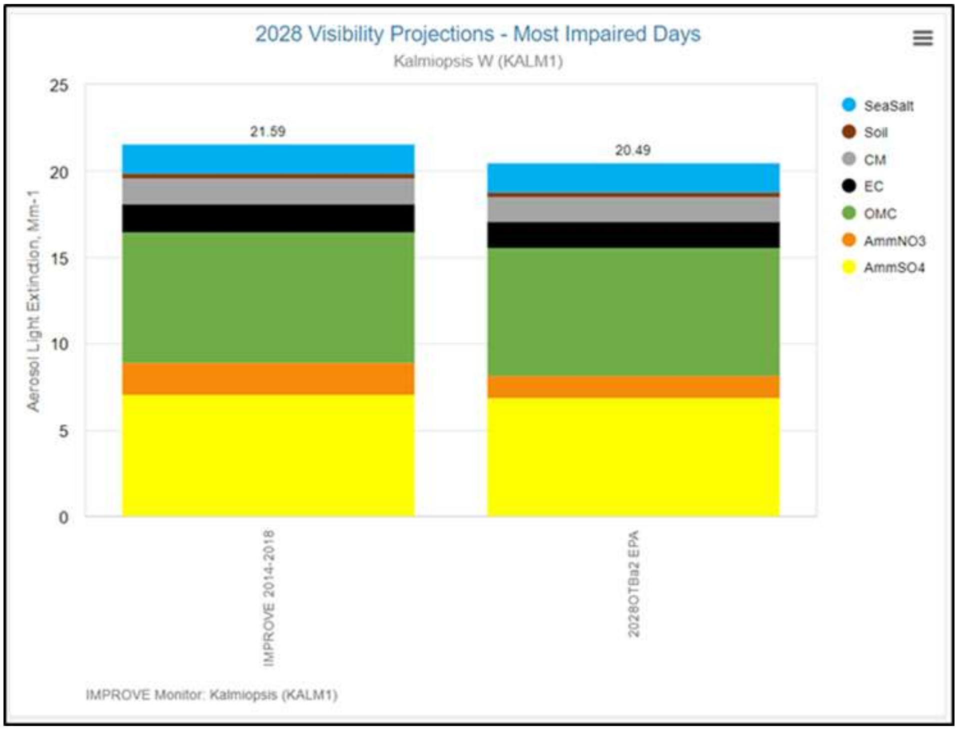

2028 Visibility Projections - Most Impaired Days
Crater Lake NP, Diamond Peak W, Mountain Lakes W, Gearhart Mountain W (CRLA1)
Aerosol Light Extinction, Mm-1
16
14
12
10
8
6
4
2
0
13.84
13.26
SeaSalt
Soil
CM
EC
OMC
AmmNO3
AmmSO4
IMPROVE 2014-2018
2028OTBa2 EPA
IMPROVE Monitor: Crater Lake NP (CRLA1)

Figure 2-14: KALM monitor, Projected 2028 visibility using SMAT.



2.5.2 Weighted Emission Potential and Source Apportionment

In addition to source apportionment modeling, DEQ relied on the WRAP weighted emission potential analysis for the development of this plan, using WEP to categorize anthropogenic sources into electric generating units, non-EGUs, oil and gas sources, mobile sources (onroad and nonroad) and nonpoint sources. The Nonpoint or area source category includes residential wood combustion, fugitive dust, agricultural sources and prescribed burning. The WEP methodology to identify source categories and sources contributing to visibility extinction at each IMPROVE monitor includes:

1) Monitored extinction data by component
2) Back trajectories using the HYSPLIT model with five years of wind data
3) Residence Time of the back trajectories passing over the 36 km grid cells in the trajectory domain for each IMPROVE monitor
4) The Extinction Weighted Residence Time
5) The calculation of the WEP that takes the EWRT and factors in emissions in the grid cell and the distance of the grid cell from the IMPROVE monitor.

Each grid cell in the model has its own unique RT and EWRT. These numbers are based on the number of HYSPLIT back trajectories that pass over that grid cell on its way to the IMPROVE monitor and the species extinction, such as NO_3, associated with each trajectory. The RT and EWRT for each cell applies to all sources in the grid cell. The WEP analysis can add refinement to the low-level State Source-Sector apportionment for assessing the relative contributions from different source categories. In contrast to the State Source-Sector apportionment, which is based on modeled predictions of 2028 OTB emissions, the WEP is based on 2017 emissions and back trajectories. DEQ assumes the emissions for 2017 and the predicted emissions for 2028 are roughly correlative between sources, and between source categories, and the winds and meteorology controlling the back trajectory analysis are good approximations of the meteorology used in the source apportionment modeling. Under these assumptions, data from the WEP analysis can supplement and expand on the source apportionment modeling of Regional Source and State Source Sector categories.

Table 2-12 through Table 2-17 show the WEP analysis of the major pollutant contributions at each IMPROVE site in Oregon, by source category. These results are based on 2028 OTB emissions in all of the 36 km grid cells in the back trajectory domain for each of the IMPROVE monitors. The WEP values in the tables are shown as unitless, but are the product of extinction in Mm-1, residence time in %, and Q/d as emissions in tons per year divided by distance in kilometers. The WEP emissions categories are NOx, SOx, primary organic aerosol (abbreviated POA) and primary elemental carbon (abbreviated PEC).

Table 2-12: STAR, Weighted emission potential values (unitless) by pollutant and source category.

		STAR 2028OTB WEP=Bext x RT x Q/d				
		wep_nox	wep_sox	wep_poa	wep_pec	Description
EGU Point	Sum =	298,716	37,850	29,243	8,022	Electric generating units
Non-EGU Point	Sum =	1,405,068	455,907	82,383	6,606	Industrial activities and airports
Non Point	Sum =	1,010,391	223,064	1,262,160	31,245	Low-level area: non-pt, ag., RWC, and fugitive dust
On-Road Mobile	Sum =	2,455,407	24,702	41,764	8,790	On-road mobile sources
Non-Road Mobile	Sum =	2,428,393	22,645	59,060	19,574	Off highway: non-road, commercial marine, and rail
Oil & Gas	Sum =	160,246	3,355	1,863	322.0	Oil & G area & pt sources (Upstream and Midstream)
Total Anthropogenic	Sum =	7,797,542	768,386	1,476,602	74,679	All anthropogenic emissions

Table 2-13: MOHO, Weighted emission potential values (unitless) by pollutant and source category.

		MOHO 2028OTB WEP=Bext x RT x Q/d				
		wep_nox	wep_sox	wep_poa	wep_pec	Description
EGU Point	Sum =	128,296	41,285	16,166	4,259	Electric generating units
Non-EGU Point	Sum =	4,036,820	1,845,007	197,764	20,672	Industrial activities and airports
Non Point	Sum =	3,596,444	1,892,050	4,074,635	103,622	Low-level area: non-pt, ag., RWC, and fugitive dust
On-Road Mobile	Sum =	5,674,369	159,074	145,813	24,009	On-road mobile sources
Non-Road Mobile	Sum =	5,689,775	127,862	216,713	55,332	Off highway: non-road, commercial marine, and rail
Oil & Gas	Sum =	190,037	3,862	2,134	319	Oil & G area & pt sources (Upstream and Midstream)
Total Anthropogenic	Sum =	19,317,985	4,069,436	4,653,242	208,235	All anthropogenic emissions

Table 2-14: THSI, Weighted emission potential values (unitless) by pollutant and source category.

		THSI 2028OTB WEP=Bext x RT x Q/d				
		wep_nox	wep_sox	wep_poa	wep_pec	Description
EGU Point	Sum =	49,406	48,479	19,393	2,416	Electric generating units
Non-EGU Point	Sum =	881,675	1,075,824	285,548	12,730	Industrial activities and airports
Non Point	Sum =	650,462	754,867	2,923,256	54,528	Low-level area: non-pt, ag., RWC, and fugitive dust
On-Road Mobile	Sum =	1,330,405	69,637	105,645	15,125	On-road mobile sources
Non-Road Mobile	Sum =	1,084,086	57,014	146,895	26,497	Off highway: non-road, commercial marine, and rail
Oil & Gas	Sum =	18,098	1,668	1,277	118	Oil & G area & pt sources (Upstream and Midstream)
Total Anthropogenic	Sum =	4,017,950	2,008,019	3,482,087	111,492	All anthropogenic emissions

Table 2-15: CRLA, Weighted emission potential values (unitless) by pollutant and source category.

CRLA 2028OTB WEP=Bext x RT x Q/d		wep_nox	wep_sox	wep_poa	wep_pec	Description
EGU Point	Sum =	67,952	39,601	26,825	1,942	Electric generating units
Non-EGU Point	Sum =	308,397	290,281	139,118	7,173	Industrial activities and airports
Non Point	Sum =	213,919	225,548	756,550	22,927	Low-level area: non-pt, ag., RWC, and fugitive dust
On-Road Mobile	Sum =	530,724	26,054	29,724	6,179	On-road mobile sources
Non-Road Mobile	Sum =	425,200	19,095	37,364	9,359	Off highway: non-road, commercial marine, and rail
Oil & Gas	Sum =	14,646	2,188	1,204	96	Oil & G area & pt sources (Upstream and Midstream)
Total Anthropogenic	Sum =	1,580,550	604,131	990,929	47,934	All anthropogenic emissions

Table 2-16: KALM, Weighted emission potential values (unitless) by pollutant and source category.

KALM 2028OTB		wep_nox	wep_sox	wep_poa	wep_pec	Description
EGU Point	Sum =	152,457	50,084	75,929	1,880	Electric generating units
Non-EGU Point	Sum =	428,089	271,641	349,602	9,570	Industrial activities and airports
Non Point	Sum =	240,685	194,022	1,147,387	28,050	Low-level area: non-pt, ag., RWC, and fugitive dust
On-Road Mobile	Sum =	595,223	19,517	38,238	6,042	On-road mobile sources
Non-Road Mobile	Sum =	524,119	30,285	60,728	10,773	Off highway: non-road, commercial marine, and rail
Oil & Gas	Sum =	4,364	385	355	23.1	Oil & G area & pt sources (Upstream and Midstream)
Total Anthropogenic	Sum =	1,951,754	566,481	1,672,425	56,537	All anthropogenic emissions

Table 2-17 HECA, Weighted emission potential values (unitless) by pollutant and source category.

HECA 2028OTB WEP=Bext x RT x Q/d		wep_nox	wep_sox	wep_poa	wep_pec	Description
EGU Point	Sum =	834,659	38,816	45,585	2,990	Electric generating units
Non-EGU Point	Sum =	2,273,748	278,698	75,265	4,746	Industrial activities and airports
Non Point	Sum =	2,036,044	131,473	1,254,935	27,318	Low-level area: non-pt, ag., RWC, and fugitive dust
On-Road Mobile	Sum =	5,140,591	15,582	37,663	7,396	On-road mobile sources
Non-Road Mobile	Sum =	3,666,368	7,281	50,091	12,591	Off highway: non-road, commercial marine, and rail
Oil & Gas	Sum =	169,449	1,465	1,094	121	Oil & G area & pt sources (Upstream and Midstream)
Total Anthropogenic	Sum =	14,168,399	473,909	1,464,713	55,250	All anthropogenic emissions

3. Stationary source emissions and controls analysis

EPA guidance from August 2019 states that a Class 1 Area meeting its reasonable progress goals is not a "safe harbor," and that a state must still determine the emission reduction measures that are necessary to make reasonable progress based on the four statutory factors and include such measures in the regional haze Long-term Strategy [40 CFR 51.308(f)(2)].

Based on the 2017 Regional Haze Rule, EPA's August 2019 Technical Guidance, and in alignment with other states in the WRAP, DEQ conducted source screening for stationary sources based on the "Q/d" index, where Q is the total tons per year of haze-forming pollutants for a facility (NO_x, PM10, and SO_2), and d is the distance in kilometers from the facility to the edge of a Class 1 Area. DEQ consulted with states in the WRAP partnership regarding the effects of sources outside of Oregon on Oregon Class 1 areas, as well as the effect of Oregon sources on Class 1 areas in adjacent states.

Additional information that DEQ consulted in selecting sources for the Four Factor Analysis, and in the determination of feasible controls and emission reductions, are data and analyses provided on the WRAP TSS website. These include:

1) Analyzing IMPROVE visibility data,

2) Performing a back trajectory analyses using 2014 – 2017 meteorological data

3) Calculating the Residence Time that the trajectories have over each 36 km grid cell centered on each IMPROVE site.

4) Weighting each grid cell RT by the extinction of each component (e.g. ammonium nitrate) at the IMPROVE site when the trajectory passes over the grid cell. The result is an Extinction Weighted Residence Time for each grid cell.

5) Multiplying the EWRT of each component (e.g. nitrate) by the grid cell emissions/distance (Q/d) value for the precursor (e.g. NOx). The resulting value is the Weighted Emission Potential for the grid cell.

DEQ considered 31 facilities where Q/d exceeded 5.00 as initially required to go through an FFA process. The FFA process derives from 40 CFR 51.308(f)(2)(i) where the 2017 Regional Haze Rule lays out the factors that states must consider in establishing reasonable progress goals. Those factors are: costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources.

DEQ presented an option for facilities where actual emissions were below the Q/d threshold; if those sources agreed to lower Plant Site Emission Limits such that Q/d was less than 5, those facilities could “screen out” and DEQ would not require further analysis from those facilities.

DEQ worked with the remaining facilities that did not screen out of further analysis as they proceeded through the FFA process. DEQ, in consultation with EPA and other states, developed criteria by which to assess the cost effectiveness of pollution controls. DEQ considered the results of the initial cost effectiveness analysis and additional information facilities submitted. In addition, DEQ employed a weight of evidence approach to better understand regional model results.

EPA’s 2019 Guidance describes several elements a state may wish to consider in assessing “energy and other non-air environmental effects” of source controls, including effects on energy consumption, waste disposal and water quality, as well as beneficial effects. In assessing potentially beneficial non-air environmental effects of source controls, DEQ completed an environmental justice analysis which presents preliminary vulnerability indices of populations living near subject facilities. DEQ did not analyze potential public health benefits on these populations but is confident that public health benefits will arise from PM and NO_x controls, in particular.

DEQ did not analyze environmental co-benefits of reducing haze forming pollutants; however, DEQ is aware of the ecological importance of reducing nitrogen and sulfur deposition in sensitive areas, such as high elevation lakes and streams. The National Park Service has studied and published on acidification effects of sulfur and nitrogen deposition and the nutrient enrichment effects of nitrogen deposition. The effects of excess sulfur and nitrogen deposition include acidification of water and soils, eutrophication and toxic algal blooms in lakes and general disruption of nutrient cycling, which adversely affects plant and animal communities.[15]

NPS published studies in 2011, based in part on 2002 National Emissions Inventory data and projections from EPA's Community Multi-scale Air Quality model. Sullivan *et al.* (2011a,b) [16,17] found Crater Lake National Park to be at high risk of acidification and nutrient enrichment, although nitrogen and sulfur pollutant loading in that region was relatively low. Sullivan, *et al*. (2011c)[18] found nitrogen deposition (expressed as kilograms/hectare/year) in the Columbia River Gorge to be in the low to mid-range nationally (5 – 15 kg-N/ha/yr), but higher than surrounding areas in the North Coast and Cascades Network. While DEQ did not quantitatively assess other environmental co-benefits of haze forming pollutant emission reductions, potential co-benefits have informed DEQ's Long-term Strategy for the 2018 - 2028 implementation period.

3.1. Q/d screening process

DEQ screened sources for four factor analysis using the Q/d metric, as recommended in EPA's 2019 guidance Step 3: Selection of sources for analysis and the Western Regional Air Partnership Methodology.[19] Q/d is a measurement of the ratio of facility-level emissions (Q) to the distance from the facility to a Class 1 Area (d), and can serve as a surrogate for the baseline visibility impact of the facility's emissions on that Class 1 Area. EPA's 2019 guidance describes the Q/d metric as:

> A state may use a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts, along with a reasonably selected threshold for this metric. This metric is a less reliable indicator of actual visibility impact because it does not consider transport direction/pathway, dispersion and photochemical processes, or the particular days that have the most anthropogenic impairment due to all sources. Therefore, it is recommended that use of this technique be limited to source selection for the purpose of developing a list of sources for which a state may conduct a four-factor analysis.

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[15] Nitrogen and Sulfur Pollution in Parks. https://www.nps.gov/subjects/air/nature-nitrogensulfur.htm#critical, accessed 01/20/22.

[16] Sullivan *et al.,* (2011a): Sullivan, T. J., G. T. McPherson, T. C. McDonnell, S. D. Mackey, and D. Moore. 2011. Evaluation of the sensitivity of inventory and monitoring national parks to acidification effects from atmospheric sulfur and nitrogen deposition: Klamath Network (KLMN). Natural Resource Report NPS/NRPC/ARD/NRR—2011/360. National Park Service, Denver, Colorado.

[17] Sullivan *et al*. (2011b): Sullivan, T. J., T. C. McDonnell, G. T. McPherson, S. D. Mackey, and D. Moore. 2011.Evaluation of the sensitivity of inventory and monitoring national parks to nutrient enrichment effects from atmospheric nitrogen deposition: Klamath Network (KLMN). Natural Resource Report NPS/NRPC/ARD/NRR—2011/312. National Park Service, Denver, Colorado.

[18] Sullivan, et al. (2011c): Sullivan, T. J., G. T. McPherson, T. C. McDonnell, S. D. Mackey, and D. Moore. 2011. Evaluation of the sensitivity of inventory and monitoring national parks to acidification effects from atmospheric sulfur and nitrogen deposition: North Coast and Cascades Network (NCCN). Natural Resource Report NPS/NRPC/ARD/NRR—2011/365. National Park Service, Denver, Colorado.

[19] Western Regional Air Partnership Technical Support System V2. "Methodology For Development Of The Q/D Analysis For Screening Sources Of Regional Haze-Forming Emissions." **http://views.cira.colostate.edu/tssv2/emissions/qdanalysis.aspx** (accessed 1/10/2020)

WRAP's methodology also recommends that states target sources with larger Q/d values that will account for a reasonably large fraction of all the in-state major, minor and area stationary source emissions contributing to regional haze. WRAP also refers to EPA draft Regional Haze guidance that states that 80 percent could be considered a reasonably large fraction of the extinction budget to be captured.

WRAP defined Q/d as:

- Q = $NO_x + SO_2 + PM_{10}$ (tons per year)
- d = distance from a source to the boundary of a Class 1 Area (km)

The parameter *d* was calculated by the GenerateNear function using the Oregon Geolocator in ArcGISPro for all Class 1 Areas within 400 km of the Oregon state boundary only.

In alignment with the methods and criteria developed by the WRAP, the Q/d was calculated for each facility and each Class 1 Area if

- d < 400 km
- Q > 25 tpy

For both Q_{PSEL} and Q_{Actual}.

Table 3-1 shows the data and sources for each of the files used to calculate Q/D. **Error! Reference source not found.** shows a map of facilities and Class 1 Areas within 400 km of the Oregon state boundary.

Table 3-1. Data sources used to calculate Q/d.

Data	Source
Title V facility location & emission information	Oregon TRAACS – Title V Plant Site Emission Limits and 2017 NEI draft (released 9/3/2019)
ACDP facility location & emission information	Oregon TRAACS – ACDP Plant Site Emission Limits
Mandatory Class 1 Areas shapefile	EPA OAR OAQPS: https://edg.epa.gov/data/public/OAR/OAQPS/Class1/
Oregon State boundary shapefile	US Bureau of Land Management
Columbia River Gorge National Scenic Area shapefile	Columbia River Gorge Commission website

The goal of selecting sources for analysis was to capture 80% of total Q for major sources (Title V) sources. For this round of the Regional Haze Planning and Implementation Period, a Q_{PSEL} /d greater than or equal to 5 captures 80% of the total Q from major sources for all Oregon CIAs, including sources not located in Oregon.

DEQ used the Plant Site Emissions Limits for a facility in 2017 to calculate Q, and calculated d for all facilities and Class 1 Areas within a 400 km radius of Oregon state boundaries in ArcGIS. DEQ assessed facilities permitted under the Title V program and the Air Contaminant Discharge Permit program. Table 3-2 and Appendix A contain the results of the Q/d screening.

Figure 3-1: Class 1 areas and Title V facilities within 400 km of the Oregon state boundary.

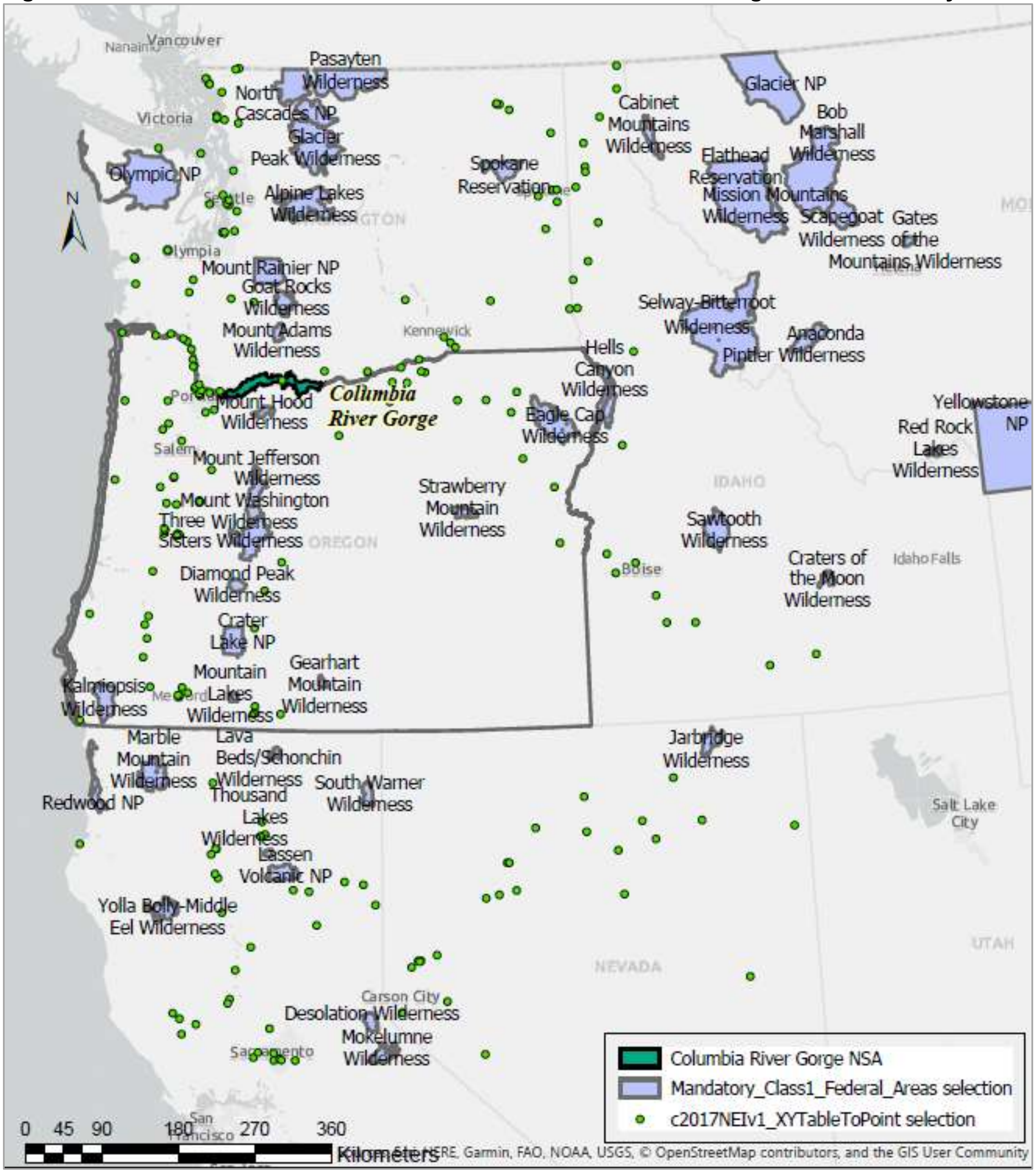

Table 3-2. Oregon facilities with Q/d greater than 5.00 that screened into four factor analysis.

Agency Facility ID	Facility Name	Permit	Fac State	Operating Status	EIS Facility ID	CIA Name	Distance (km)	Actual Emissions (tons per year)					PSEL (tons per year)					EmissYear
								NOX	PM10	SO2	Q	Q/d	NOX	PM10	SO2	Q(tpy)	Q/d	
25-0016	PGE Boardman	TV	OR	Active	8171111	Mount Hood Wilderness	142.6	1768.12	387.75	3297.87	5454	38.24	5961	1086	9525	16572	116.21	2017
208850	INTERNATIONAL PAPER	TV	OR	Active		Three Sisters Wilderness	58.9	724.02	181.39	67.64	973	16.51	1692	750	1521	3963	67.24	
05-1849	A Division of Cascades Holding US Inc.	TV	OR	Active	7219311	Mount Hood Wilderness	87.7	244.40	14.53	6.10	265	3.02	1449	738	3400	5587	63.72	2017
01-0029	Ash Grove Cement Company	TV	OR	Active	7219011	Eagle Cap Wilderness	51.9	788.00	140.82	33.10	962	18.54	1778	176	42	1996	38.47	2017
05-2520	Beaver Plant/Port Westward I Plant	TV	OR	Active	7393911	Mount Hood Wilderness	133.3	359.22	62.19	9.85	431	3.24	3776	241	595	4612	34.60	2017
10-0025	Roseburg Forest Products - Dillard	TV	OR	Active	8219211	Kalmiopsis Wilderness	81.8	1006.94	479.24	73.52	1560	19.07	1655	743	110	2508	30.67	2017
04-0004	Georgia Pacific- Wauna Mill	TV	OR	Active	8055711	Mount Hood Wilderness	145.5	1037.66	775.80	539.82	2353	16.18	2139	1077	913	4129	28.38	2017
03-2145	West Linn Paper Company	TV	OR	Active	8417511	Mount Hood Wilderness	53.7	186.13	14.99	2.72	204	3.79	597	82	743	1422	26.46	2017
22-3501	Halsey Pulp Mill	TV	OR	Active	7394911	Three Sisters Wilderness	80.4	352.06	278.81	80.92	712	8.86	687	366	851	1904	23.69	2017
26-1876	Owens-Brockway Glass Container Inc.	TV	OR	Active	8520811	Mount Hood Wilderness	55.1	403.65	76.15	118.07	598	10.86	711	132	313	1156	21.00	2017
21-0005	Georgia-Pacific- Toledo	TV	OR	Active	8418611	Three Sisters Wilderness	147.0	939.11	195.76	16.07	1151	7.83	1351	799	839	2989	20.33	2017
18-0096	Gas Transmission NW - Compressor Station #13	TV	OR	Active	7393311	Crater Lake NP	14.1	29.40	2.08	1.47	33	2.34	224	14	39	277	19.68	2017
31-0002	Particleboard	TV	OR	Active	7298311	Eagle Cap Wilderness	25.0	305.10	25.49	2.38	333	13.32	379	42	39	460	18.41	2017
18-0003	Klamath Cogeneration Proj	TV	OR	Active	9223711	Mountain Lakes Wilderness	24.4	143.00	19.56	6.40	169	6.91	314	48	39	401	16.40	2017
18-0005	Interfor Gilchrist	TV	OR	Active	8518711	Diamond Peak Wilderness	22.3	60.15	125.28	2.31	188	8.42	104	208	39	351	15.74	2017
31-0006	Elgin Complex	TV	OR	Active	8170611	Eagle Cap Wilderness	18.1	128.15	41.10	13.01	182	10.08	171	62	39	272	15.04	2017
01-0038	Baker Compressor Station	TV	OR	Active	7219111	Eagle Cap Wilderness	40.2	158.48	1.97	1.17	162	4.02	542	14	39	595	14.81	2017
12-0032	Ochoco Lumber Company	ACDP - Standard	OR	Active		Strawberry Mountain Wilderness	8.5						50	31	39	120	14.19	PSEL
09-0084	Compressor Station 12	TV	OR	Active	7410011	Three Sisters Wilderness	30.4	63.60	4.62	2.56	71	2.33	377	14	39	430	14.13	2017
302847	Oregon City Compressor Station	TV	OR	Active	8417911	Mount Hood Wilderness	43.8	156.66	1.72	1.02	159	3.64	536	16	39	591	13.49	2017
08-0003	Pacific Wood Laminates, Inc.	TV	OR	Active	8416611	Kalmiopsis Wilderness	23.5	52.50	139.12	3.27	195	8.29	76	189	29	294	12.50	2017
26-1865	EVRAZ Inc. NA	TV	OR	Active	8521611	Mount Hood Wilderness	73.1	139.40	118.74	3.27	261	3.57	493	340	39	872	11.92	2017
18-0013	Collins Products, L.L.C.	TV	OR	Active	7219711	Mountain Lakes Wilderness	23.6	6.85	105.89	0.03	113	4.78	39	166	50	255	10.82	2017
15-0159	Biomass One, L.P.	TV	OR	Active	8056211	Mountain Lakes Wilderness	56.4	239.00	15.57	14.32	269	4.77	469	48	39	556	9.86	2017
15-0073	Roseburg Forest Products- Medford MDF	TV	OR	Active	8056111	Mountain Lakes Wilderness	59.5	131.16	36.24	5.94	173	2.91	272	215	39	526	8.84	2017
18-0014	Columbia Forest Products, Inc.	TV	OR	Active	8186211	Mountain Lakes Wilderness	24.6	43.19	57.16	0.73	101	4.10	65	87	39	191	7.75	2017
15-0004	Boise Cascade- Medford	TV	OR	Active	8418111	Mountain Lakes Wilderness	60.6	113.42	125.26	15.00	254	4.19	227	167	31	425	7.02	2017
10-0045	Swanson Group Mfg. LLC	TV	OR	Active	8004811	Kalmiopsis Wilderness	48.8	55.24	144.76	2.99	203	4.16	80	193	39	312	6.39	2017
18-0006	dba JELD-WEN	TV	OR	Active	7219611	Mountain Lakes Wilderness	21.1	26.59	16.78	1.58	45	2.13	67	27	39	133	6.30	2017
15-0025	Timber Products Co. Limited Partnership	TV	OR	Active	8054711	Mountain Lakes Wilderness	59.4	69.18	25.21	2.43	97	1.63	162	159	39	360	6.07	2017
10-0078	Roseburg Forest Products- Riddle Plywood	TV	OR	Active	8005011	Kalmiopsis Wilderness	68.9	79.49	50.16	15.13	145	2.10	199	127	39	365	5.29	2017
204402	KINGSFORD MANUFACTURING COMPANY	TV	OR	Active		Three Sisters Wilderness	61.0	289.12	177.59	44.1	511	8.38						

Last updated 1/10/2020

3.2. Impact of Oregon facilities on other states' Class 1 areas

Table 3-3 shows the list of Oregon facilities that had a Q/d of greater than 5.00 for a non-Oregon Class 1 area, and the closest Class 1 area. The full list of potentially impacted Class 1 areas for each facility is located in Appendix B. Oregon facilities with potential visibility impacts in other states. Unless they screened out by reducing Plant Site Emission Limits to Q/d < 5.00, all of the facilities in Table 3-3 underwent four factor analysis for their impact on at least one Oregon Class 1 area.

Table 3-3. Oregon facilities with potential visibility impacts on other states.

Agency Facility ID	Facility Name	Fac State	Closest non-Oregon Class 1 area	CIA State	Distance (km)	Q/d Actual	Q/d PSEL
05-1849	A Division of Cascades Holding US Inc.	OR	Mount Adams Wilderness	WA	98.41	2.69	56.77
01-0029	Ash Grove Cement Company	OR	Sawtooth Wilderness	ID	181.25	5.31	11.01
05-2520	Beaver Plant/Port Westward I Plant	OR	Mount Rainier NP	WA	114.86	3.75	40.15
15-0159	Biomass One, L.P.	OR	Marble Mountain Wilderness	CA	87.83	3.06	6.33
15-0004	Boise Cascade-Medford	OR	Marble Mountain Wilderness	CA	78.01	3.25	5.45
18-0013	Collins Products, L.L.C.	OR	Lava Beds/Schonchin Wilderness	CA	46.50	2.43	5.48
26-1865	EVRAZ Inc. NA	OR	Mount Adams Wilderness	WA	107.17	2.44	8.14
04-0004	Georgia Pacific-Wauna Mill	OR	Mount Rainier NP	WA	131.17	17.94	31.48
21-0005	Georgia-Pacific-Toledo	OR	Mount Adams Wilderness	WA	248.27	4.64	12.04
22-3501	Halsey Pulp Mill	OR	Mount Adams Wilderness	WA	228.78	3.11	8.32
18-0003	Klamath Cogeneration Project	OR	Lava Beds/Schonchin Wilderness	CA	46.14	3.66	8.69
03-2729	Oregon City Compressor Station	OR	Mount Adams Wilderness	WA	106.80	1.49	5.53
26-1876	Owens-Brockway Glass Container Inc.	OR	Mount Adams Wilderness	WA	97.54	6.13	11.85
25-0016	PGE Boardman	OR	Mount Adams Wilderness	WA	137.66	39.62	120.38
10-0025	Roseburg Forest Products - Dillard	OR	Redwood NP	CA	150.14	10.39	16.70
03-2145	Willamette Falls Paper Company	OR	Mount Adams Wilderness	WA	116.25	1.75	12.23

3.3. Impact of facilities in other states on Oregon Class 1 areas

The 2017 Regional Haze Rule requires states to investigate and plan for out-of-state facility emissions that affect visibility in that state's Class 1 areas (40 CFR 51.308(f)(2)(ii)). Specifically, "the State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class 1 Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress." Through state consultations during 2019 and 2020 (described in Section 6.2), Q/d calculations, and the regional model available through WRAP, DEQ identified the facilities listed in Table 3-4 as being reasonably likely to contribute to visibility impairment in Oregon Class 1 areas. DEQ's high level analysis did not quantify meteorological characteristics, such as predominant wind direction between points, other than by considering WRAP model results that included those inputs. All of these facilities were on the four factor analysis lists for their respective states.

Eleven facilities located in Washington may impair visibility in the Mt. Hood Wilderness area in Oregon. According to draft documents posted on Washington Ecology's Regional Haze webpage, Ecology relied on the 2014 National Emissions Inventory for Regional Haze Round 2 input. Ecology used a Q/d ratio of 10 as the threshold for facilities to screen into FFA.[20] For oil refinery facilities where Ecology found pollution controls reasonable, Ecology will implement those decisions through state rules governing Reasonably Available Control Technology, with controls installed in the next Regional Haze implementation period. As, well, Ecology will issue orders and consent decrees to several facilities during this implementation period. The Agreed Orders include NO_x reductions at TransAlta until that facility ceases coal-fired power generation in 2025, and AOs with two Alcoa Intalco smelters to do an FFA prior to start-up and implement identified controls approved by Ecology within three years of startup. Ecology also currently has a consent decree with Cardinal Glass for NO_x reductions.

According to written communications between Idaho Department of Environmental Quality and Oregon DEQ, Idaho screened 10 facilities into FFA based on a Q/d threshold of 2. As of this writing, Idaho DEQ had not reached final decisions regarding facility controls, but shared the Clearwater facility FFA with Oregon DEQ.

According to notes from the Nevada – Oregon state consultation meeting and subsequent electronic mail communications, Nevada Division of Environmental Protection screened in 8 facilities based on a Q/d > 4 and required five of the largest emitting facilities to go through FFA. The owners of one of these facilities, the North Valmy power plant, determined to affect visibility in an Oregon Class 1 area, may close the plant by 2028. The FFA for this facility showed all control technology to exceed a cost effectiveness threshold of $8,000/ton for NO_x and SO_2. Nevada will pursue regulatory emissions limits for the North Valmy plant based on the reduced generating capacity of the plant due to the departure of an operating partner. Idaho Power will no longer exercise its 50% ownership in the North Valmy generating station and will cease obtaining any power from the plant in 2021. Nevada will continue discussions with the plant operator, NV Energy, concerning possible closure scenarios, the timing of which may or may not factor into Nevada's regional haze planning.

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[20] Regional Haze SIP Revision – DRAFT Second 10-Year Plan, Chapter 11: Four Factor Analysis. https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/docs/RhSIPCh11202101.pdf and March 31, personal communications.

Table 3-4. Facilities in other states reasonably likely to cause visibility impairment in Oregon Class 1 areas.

Facility Name	Fac State	OR CIA Name	d (km)	Q-act (tpy)	Q/d Act	NO_X Act	PM10-PRI Act	SO_2 Act	FFA Decision[21]
TransAlta Centralia Generation, LLC	WA	Mount Hood	169.98	8,323.32	48.97	6,214.37	419.33	1,689.62	• Will cease coal-fired power generation by 12/31/25. • reduced NOX emission standard for remaining facility life.
Nippon Dynawave Packaging Co.	WA	Mount Hood	118.70	2,463.94	20.76	1,949.43	124.30	390.21	• Control measures do not appear necessary to meet the reasonable progress goals and would not provide meaningful visibility improvement. • Ecology will reevaluate these sources during the next implementation period.
Georgia-Pacific Consumer Operations LLC	WA	Mount Hood	45.45	689.00	15.16	486.00	163.00	40.00	
Boise Paper	WA	Eagle Cap	114.04	1,656.24	14.52	637.27	133.56	885.41	
Longview Fibre Paper and Packaging, Inc. dba KapStone Kraft Paper Corporation	WA	Mount Hood	113.46	1,449.26	12.77	1,040.95	210.33	197.98	
WestRock Tacoma Mill	WA	Mount Hood	210.43	1,532.36	7.28	1,120.90	221.74	189.72	
Alcoa Primary Metals Intalco Works	WA	Mount Hood	386.45	4,776.22	12.36	190.17	598.71	3,987.34	• Not cost reasonable to add emission control devices. • Currently in curtailment.
BP Cherry Point Refinery	WA	Mount Hood	391.39	2,808.00	7.17	1,918.00	82.00	808.00	• Additional controls are cost-effective. • Ecology recommends RACT rule development
Tesoro Northwest Company	WA	Mount Hood	347.26	2,194.33	6.32	1,970.78	143.83	79.72	
Ash Grove Cement Company	WA	Mount Hood	241.76	1,466.47	6.07	1,367.89	29.15	69.42	• Unreasonable cost to install equipment. • Recent upgrade of PM controls. • Recent consent decree addressed SO_2, NO_X, and PM emissions.

[21] From Washington Regional Haze website: https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze;

Facility Name	Fac State	OR CIA Name	d (km)	Q-act (tpy)	Q/d Act	NO_X Act	PM10-PRI Act	SO_2 Act	FFA Decision[21]
Cardinal FG Winlock	WA	Mount Hood	151.89	881.83	5.81	809.14	16.47	56.22	• Installation SCR in 2021; large decrease in NO_X; minor increase in PM and SO_2. • New permit limit for ammonia of 10 ppm and 9.5 tpy is reasonable.
Clearwater Paper Corp. - PPD & CPD	ID	Hells Canyon	70.62	1,614.27	22.86	1,372.03	191.14	51.09	• Awaiting information on FFA decision.
Valmy Cooling Tower #2	NV	Gearhart Mountain	348.95	2,858.07	8.19	1,218.79	51.01	1,588.27	• Best case scenario – close by 2028. • Second option – modify permit per FFA.

3.4. Four factor analysis

The four factors that the 2017 Regional Haze Rule and guidance require facilities and DEQ to consider for this planning period are: (1) cost of controls; (2) time necessary to install controls; (3) remaining useful life; and (4) energy and other non-air environmental impacts.

DEQ sent 31 facilities letters in December 2019, notifying those sources that DEQ had found their potential emissions to exceed a Q/d = 5 threshold, and that DEQ was requesting information to begin the FFA process. Facilities initially had until May 31, 2020, to conduct those analyses. DEQ extended the deadline until June 15, 2020, upon request from some facilities to accommodate challenges arising from COVID-19.

If a facility's actual emissions were below the screening threshold and potential emissions above the screening threshold, DEQ provided the source an opportunity to reduce Plant Site Emission Limits to a point where Q/d would be less than 5.00. If a facility chose the option to reduce PSELs, DEQ exempted the source from further control analysis. Seven facilities took this option by June 2020. In the following months, one facility found the controls to be cost effective and a second had recently completed a controls analysis, so DEQ did not required additional analysis.

DEQ received FFA information from those facilities that had not opted for PSEL reductions or were otherwise exempt from FFA by June 15, 2020. DEQ reviewed the submitted FFA information and consulted with other states to strive for consistency, where appropriate, in identifying criteria and screening levels used in assessing presumed cost-effectiveness of pollution controls. The process and criteria that DEQ used to identify the emission units for additional review and information were:

- Step 1: Divide emissions units for each facility into three bins:
    - Bin 1. Likely cost-effective candidates. Control devices with cost less than $10,000/ton, or those that appear to be technically feasible but for which no cost analysis was provided.
    - Bin 2. Retain for further analysis. Control devices with cost more than $10,000/ton but less than $30,000/ton.
    - Bin 3. Cost is unlikely to be reasonable. Above $30,000/ton.
- Step 2: Adjust cost estimates for consistency among emissions units.
    - Bins 1 & 2. Adjust for basic factors (PSEL, interest rate, useful life).
    - Bin 3. No further analysis. Unlikely to be cost effective.

After initial review, DEQ ruled out control devices that:

- Cost of control was greater than $10,000 per ton, after adjustment to current prime rate (3.25%),[22] 30 year lifetime, and emissions at PSEL, or
- Provided an emissions reduction (using emissions at PSEL) of less than 20 tons/year.

DEQ then selected 43 emissions units at 17 facilities for additional review for a total of 62 control devices. In August 2020, DEQ notified those 17 facilities of one or more facility emissions units for which DEQ would require additional analysis. DEQ requested that facilities submit additional or more detailed information about control costs by mid-September 2020. DEQ extended

[22] Per EPA Cost Control Manual, pages 14-17: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

the deadline until the end of September due to extreme weather events, including fire and wind events, across the West in early September.

Between September 2020 and January 2021, DEQ reviewed the additional cost estimate information and sent facilities letters notifying them of DEQ's decisions about the cost effectiveness of controls. During that period and continuing through March 2021, DEQ met with facility representatives to discuss options for facilities to achieve and track the emission reductions that would be required. Figure 3.2 illustrates the timelines and decision points DEQ followed throughout the FFA process.

Figure 3-2: Four factor analysis process and timeline.

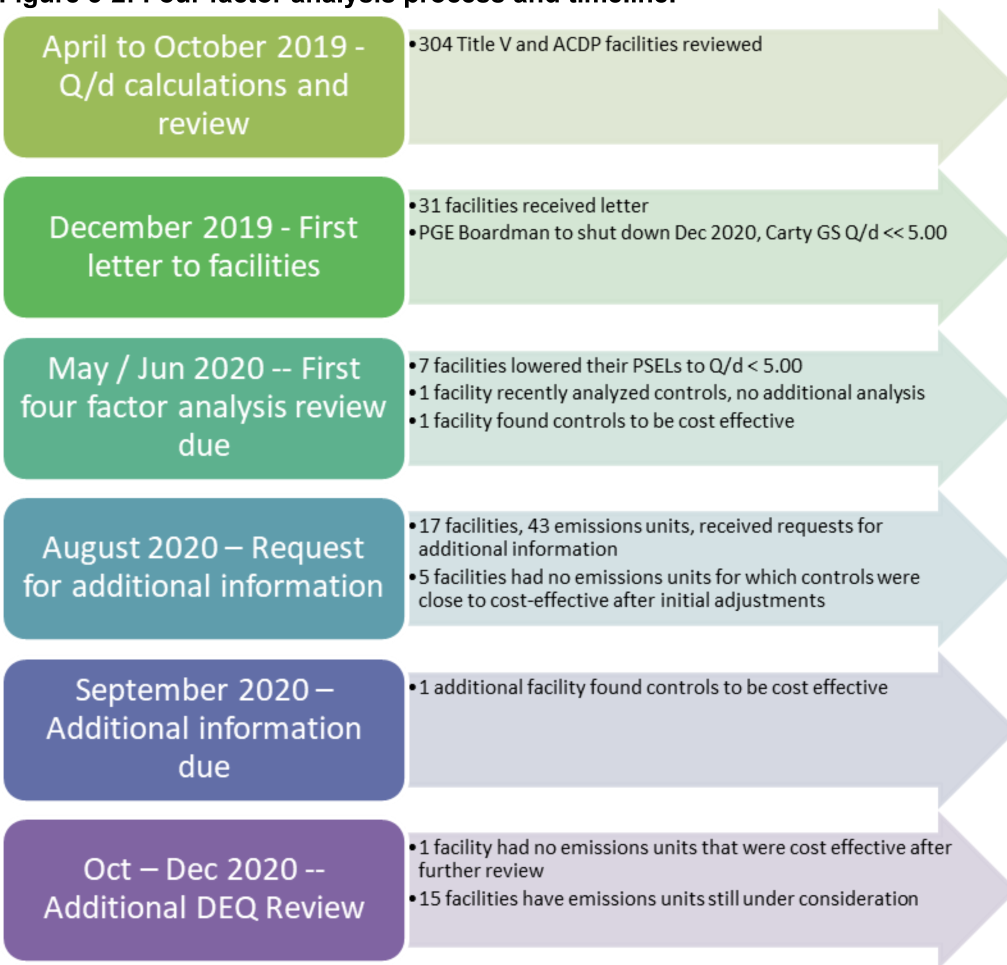
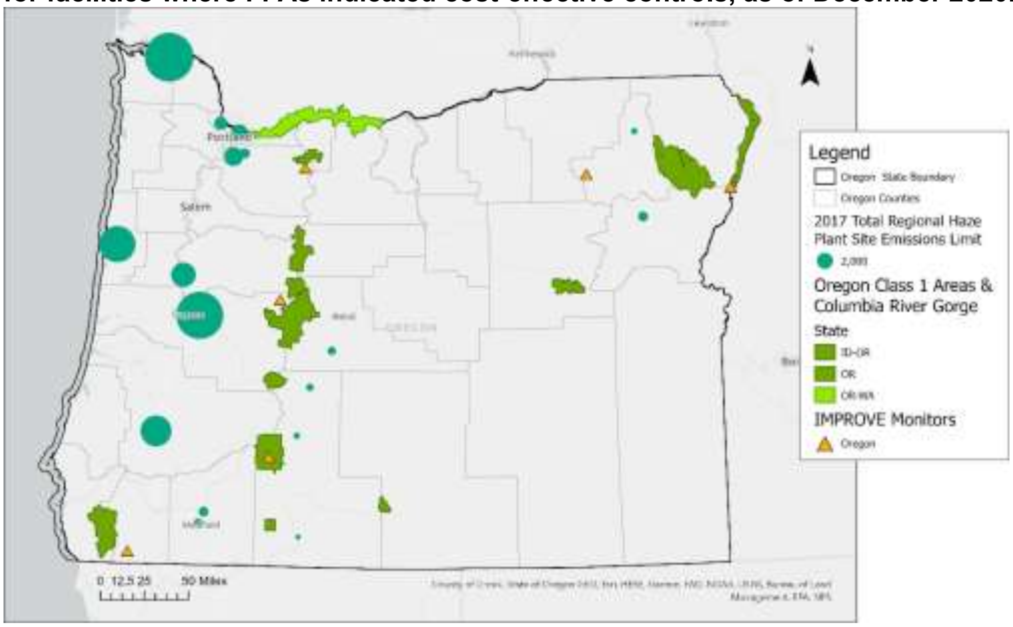


Figure 3-3 shows the total permitted emissions of regional haze-forming pollutants for the facilities where FFAs indicated cost-effective controls.

Figure 3-3: Total Plant Site Emissions Limits (tons per year) of Regional Haze Forming Pollutants for facilities where FFAs indicated cost-effective controls, as of December 2020.



3.5. Division 223 Rulemaking

In July 2021, the Oregon Environmental Quality Commission, DEQ's rulemaking board, adopted rules in Oregon Administrative Rules Chapter 340 Division 223 that codified the Q/d screening procedure, establishing what sources DEQ would require to take action under Regional Haze Round 2, and the four factor analysis process. DEQ had existing authority under OAR 340-214-0110 to request information from facilities related to the four factor analysis, but the revised Division 223 rules gave DEQ additional authority to establish requirements and compliance options for facilities regulated under Regional Haze Round 2. The July 2021 revisions to Division 223 also repealed rules that implemented the first round of Regional Haze requirements for the Portland General Electric coal-fired facility in Boardman, OR and which were no longer relevant because that facility closed in December 2020. DEQ includes the Division 223 rules, as filed with the Oregon Secretary of State in July 2021, in Appendix D.

DEQ's authority under Division 223 allowed DEQ to fulfill the requirement under the federal 2017 Regional Haze Rule that Regional Haze Plans include enforceable emission reductions of haze-forming pollutants. In Section 3.7 of this plan, DEQ documents the agency's FFA findings, facilities' compliance decisions and resulting orders issued to stationary sources under DEQ's Division 223 authority.

3.6. Weight of evidence approach

DEQ first assessed the four factors as required 40 CFR 51.308 (d)(1)(i)(A) to determine reasonable progress goals. Following the FFA process, DEQ applied a weight of evidence approach to qualitatively assess potential connections between a facility's emissions and visibility impairment in Class 1 areas, as well as co-benefits to surrounding communities potentially associated with emission reduction. Weight of evidence approaches are commonly used in ecological assessment and health risk assessment. They are used when an inference needs to be drawn from various and heterogeneous pieces of evidence.

DEQ followed the methodology described in Suter, *et al.* (2017) for qualitative assessments.[23] **Error! Reference source not found.** shows the factors and relative weighting that DEQ considered to assess environmental impacts and potential connection between a facility's emissions and visibility impairment on a most impaired day.

The factors DEQ weighted the most were the Q/d value, the Weighted Emission Potential analysis (described in Section 2.5.2), and the Extinction Weighted Residence Times. The Q/d, WEP and EWRT provide the strongest evidence that emissions from the facilities contribute to visibility impairment in Class 1 areas. Facilities that rank high among these four pieces of evidence indicate that reasonable controls on the facility are likely to improve visibility at Class 1 areas. DEQ relied on the WEP and EWRT analysis found on the WRAP TSS[24] for each Class 1 area.

Factors weighted in a second tier include indices representing population vulnerability and a prototype of a cumulative burden – or environmental justice - score for people residing near each source. By considering an EJ score and vulnerable population rank, DEQ can identify locations where facility controls will have the co-benefit of not only improving visibility, but also reducing environmental burden on vulnerable communities. DEQ believes that emission reductions in Oregon should be targeted towards those communities that experience the greatest burden.

Table 3-5: Scoring table for DEQ's Weight of Evidence approach, after Table 1 in Suter et al., 2017.

Statutory factor	Piece of Evidence	Relevance	Strength	Reliability	Overall weight
Facility emissions can be reasonably attributed/anticipated to cause visibility impairment on most impaired days for at least one Class 1 area in Oregon (PSEL and actual)					
	Q/d	+++	+	+	+++
	EWRT	+++	++	+++	+++
	WEP	+++	++	++	+++
Local environmental impacts					
	Vulnerable populations (0-5)	+	+	+++	++
	EJ Score (cumulative burden, 1-10)	++	++	++	++

3.6.1 Environmental Justice Analysis

The 2017 Regional Haze Rule requires states to consider what beneficial effects controls for visibility improvement are likely to have on other factors, such as public health. Environmental advocacy stakeholders have also raised the question of environmental justice benefits of Regional Haze Program reductions in pollutants to states. To better understand the potential co-benefits of pollutant controls, DEQ undertook an environmental justice analysis of communities surrounding the facilities that DEQ's Regional Haze decisions will affect.

[23] Suter et al. 2019. "A Weight of Evidence Framework for Environmental Assessments: Inferring Qualities." Integrated Environmental Assessment and Management — Volume 13, Number 6—pp. 1038–1044. http://index.osl.state.or.us/illiad/pdf/197992.pdf (Accessed 1/27/21)
[24] https://views.cira.colostate.edu/tssv2/

EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies."

Executive Order 12898 (1994) focused federal attention on the environmental and human health conditions of minority and low-income populations with the goal of achieving environmental protection for all communities. The Executive Order established an Interagency Working Group on Environmental Justice. Additionally, the Executive Order directed federal agencies to develop strategies on how to identify and address the disproportionately adverse human health and environmental effects of programs, policies, and activities on minority and low-income populations.

3.6.1.1 Vulnerable Populations Score

DEQ first identified the demographic profiles of the communities immediately surrounding the facilities for which DEQ considered controls.[25]

DEQ used data provided in the 2019 version of EJSCREEN to calculate the following measures of potentially vulnerable communities for each census block group in the state. This version of EJSCREEN uses the 2013-2017 5-year American Community Survey data for demographic indicators.

- Percent minority (percent population identifying as + percent of the population identified as Hispanic/Latino white)
- Percent low income (percent of population living in households making less than 200% of the federal income poverty level)
- Educational attainment (percent of the population over the age of 25 without a high school diploma)
- Linguistic isolation (percent of the population self-identified as speaking English "less than well")
- Percent of population under 5
- Percent of population over 64

These indicators, or variations thereof, are the standard demographic indicators used in dozens, if not hundreds of studies since the publication of *Toxic Wastes and Race* (United Church of Christ, 1987) for examining potential patterns of disproportionate burden of environmental pollution on communities of color and/or low-income communities.

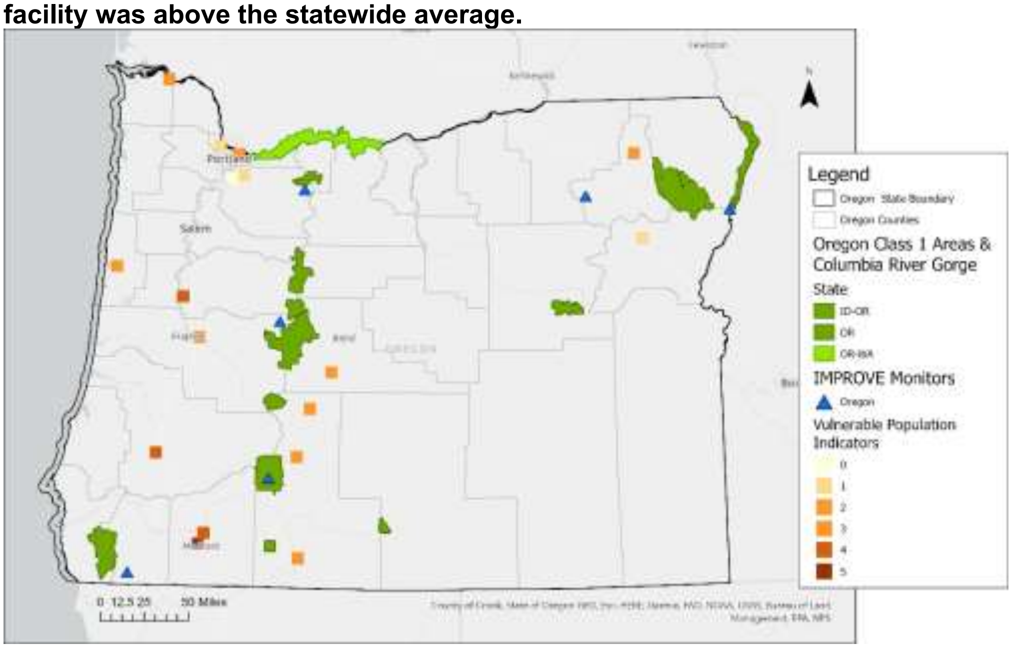
For each facility, DEQ tallied a "1" if the value of that indicator was above the statewide average, or a "0" if the value was below the statewide average. The figure below shows the number of indicators for which the community within 2.5 miles of a facility was above the statewide average in 2017 (**Error! Reference source not found.**). The maximum was 6 and the minimum was 0. If a census block group was only partially contained within the 2.5 mile radius of the facility, then the value for that census block group was scaled to the proportion of the block group within the circle.

Figure 3-4 illustrates the outcome of DEQ's vulnerable populations analysis. The analysis shows that most communities surrounding the affected Title V facilities are above the state

[25] Wu et al. 2020. Towards an assessment of cumulative environmental burden and disproportionate impact for Oregon communities. Poster presented virtually at American Geophysical Union Annual Meeting 2020.

average vulnerability score. Areas with the highest vulnerability scores were Medford, Roseburg and southeastern Linn County. Income indicators in these areas most influenced the vulnerability scores while percent minority indicators and linguistic isolation indicators most influence overall vulnerability scores in Portland and eastern Oregon counties.

Figure 3-4: Number of socioeconomic indicators for which the community within 2.5 km of a facility was above the statewide average.



DEQ completed a preliminary analysis to improve understanding about the location of particularly vulnerable communities relative to the stationary sources for which DEQ considered pollution controls to improve visibility in Class 1 areas and the Columbia Gorge[26].

3.6.1.2 Towards an Environmental Justice “Score” Methodology for Oregon

A review of the published literature shows that as of January 2021, California, Washington State, and Maryland have published their own state-specific versions of EPA EJSCREEN. In addition, DEQ is aware that Minnesota, North Carolina, and some local jurisdictions have done some work to make EPA EJSCREEN applicable to a specific geography.

[26] This EJ analysis also illustrates a method DEQ could develop further to identify “environmental justice communities” across the state. In future EJ analyses, DEQ would need to establish criteria and definitions around environmental justice. In the absence of an Oregon-specific definition of “environmental justice communities,” or a standard process for analyzing disproportionate effects, DEQ relied on best professional judgment and the academic literature to indicate where pollution reductions might have benefits (in addition to visibility improvement) to communities that experience disproportionate socioeconomic, health and environmental burdens.

The figures below are taken from the Washington Environmental Health Disparities Map Project[27] and Driver's et al. (2019) work on Maryland EJSCREEN.[28] The table below shows a high level comparison of the data inputs into CalEnviroScreen, Washington Environmental health Disparities map, and MD EJSCREEN. A detailed table in Appendix C lists the data sources used in each application, along with the inputs DEQ used in its preliminary examination of environmental justice "scores" in Oregon. DEQ attempted to identify areas of the state with higher cumulative environmental burden.

As shown in Figure 3-5, and summarized in Table 3-6Table 3-6, all the methods DEQ reviewed for calculating an EJ Score multiplied a pollution burden by a population characteristics score. Pollution burden was calculated by some averaging function of the rank percentiles of environmental exposures and environmental effects, where environmental exposures are largely air-based exposures while environmental effects were related to land and water variables. Washington's method double weighted environmental exposures over environmental effects, while Maryland's method takes an average of the rank percentiles in each category.

All methods calculate an index for population characteristics by averaging the average percentile ranks of sensitive populations and socioeconomic factors, where sensitive populations are health-based indicators, and socioeconomic factors were census-based demographic data.

Common to California, Washington, and Maryland methods was the process used to develop both the list of indicators to be shown in the tool and used in score calculations, weighting, and review of other methodological considerations. All of them involved multi-year efforts (a minimum of two years) to conduct meaningful community outreach and input into developing the tool, as well as some customization of indicators available based on health outcomes as well as environmental indicators.

If DEQ were to develop an Oregon-specific EJSCORE, the literature and other states' methods suggest the following actions would be important:

- Conduct extensive community outreach to gain input and feedback, following the Washington process;
- Partner with environmental and occupational health agency staff, and/or other sections of relevant public health agencies;
- Identify additional potentially relevant environmental data from all DEQ programs;
- Conduct additional statistical analysis of the various factors to better understand and establish meaningful thresholds (or ranges of thresholds) for scoring based on factor analysis, and the propagation of probability distributions and uncertainty throughout the various steps of the model.
    - For instance, DEQ learned that the score is sensitive to the inclusion (MD) or exclusion (WA) of the age factors (under 5, over 64).

[27] University of Washington Department of Environmental & Occupational Health Sciences. Washington Environmental Health Disparities Map: technical report. Seattle; 2019. https://deohs.washington.edu/sites/default/files/images/Washington_Environmental_Health_Disparities_Map.pdf (Accessed 12/17/20)

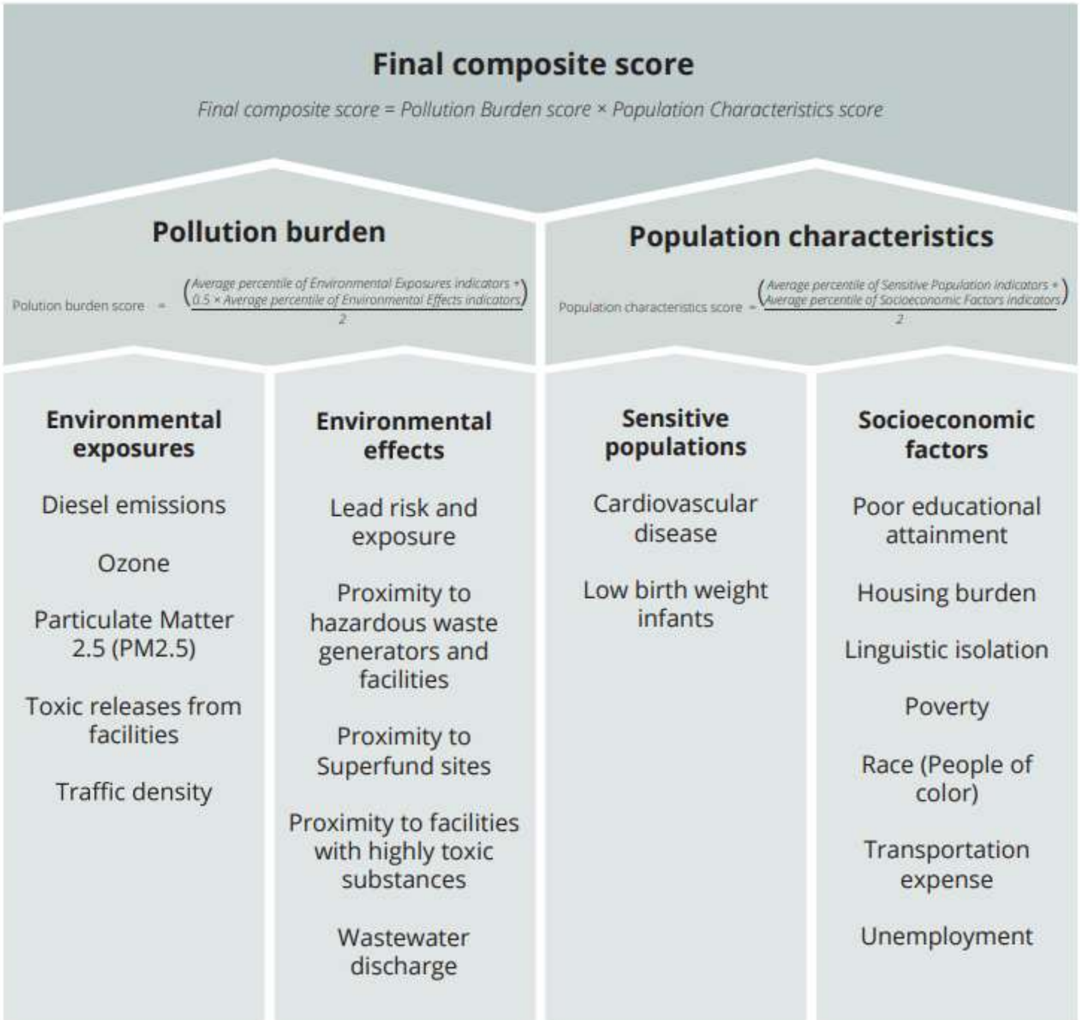
[28] Driver et al. 2019. "Utilization of the Maryland Environmental Justice Screening Tool: A Bladensburg, Maryland Case Study." **Int. J. Environ. Res. Public Health 2019**, **16**(3), 348. https://www.mdpi.com/1660-4601/16/3/348 (Accessed 12/17/20)

- However, when significance thresholds are above 60% or above 70%, that only made a difference in 2 sites out of approximately 30 locations analyzed.
- Refer to Zapata et al. (2017)[29] for an example of this methodology.

Figure 3-6 illustrates the results of DEQ's preliminary environmental justice analysis as cumulative burden scores for the populations residing within 2.5 miles of the stationary sources to be regulated under Regional Haze Round 2.

[29] Zapata et al. 2017. Findings Brief for Equity Considerations for Greenhouse Gas Emissions Cap and Trade Legislation in Oregon. https://www.oregonlegislature.gov/helm/workgroup_materials/WG%204%20-%20Marisa%20A.%20Zapata%20Findings%20Brief.pdf (Accessed June 2020)

Figure 3-5: A comparison of Washington Environmental Health Disparities map and Maryland's MD EJSCREEN.



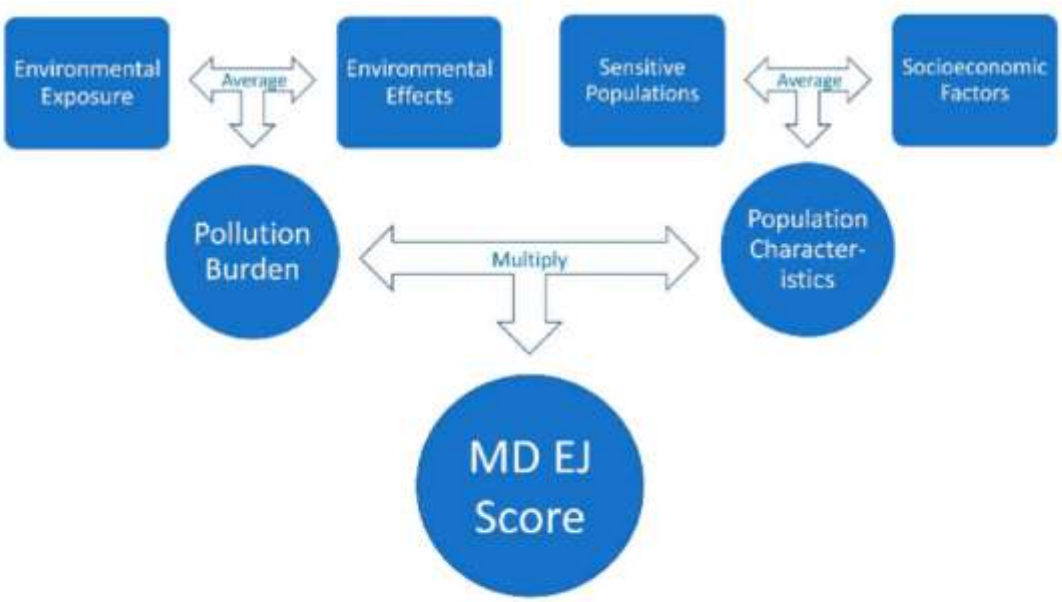
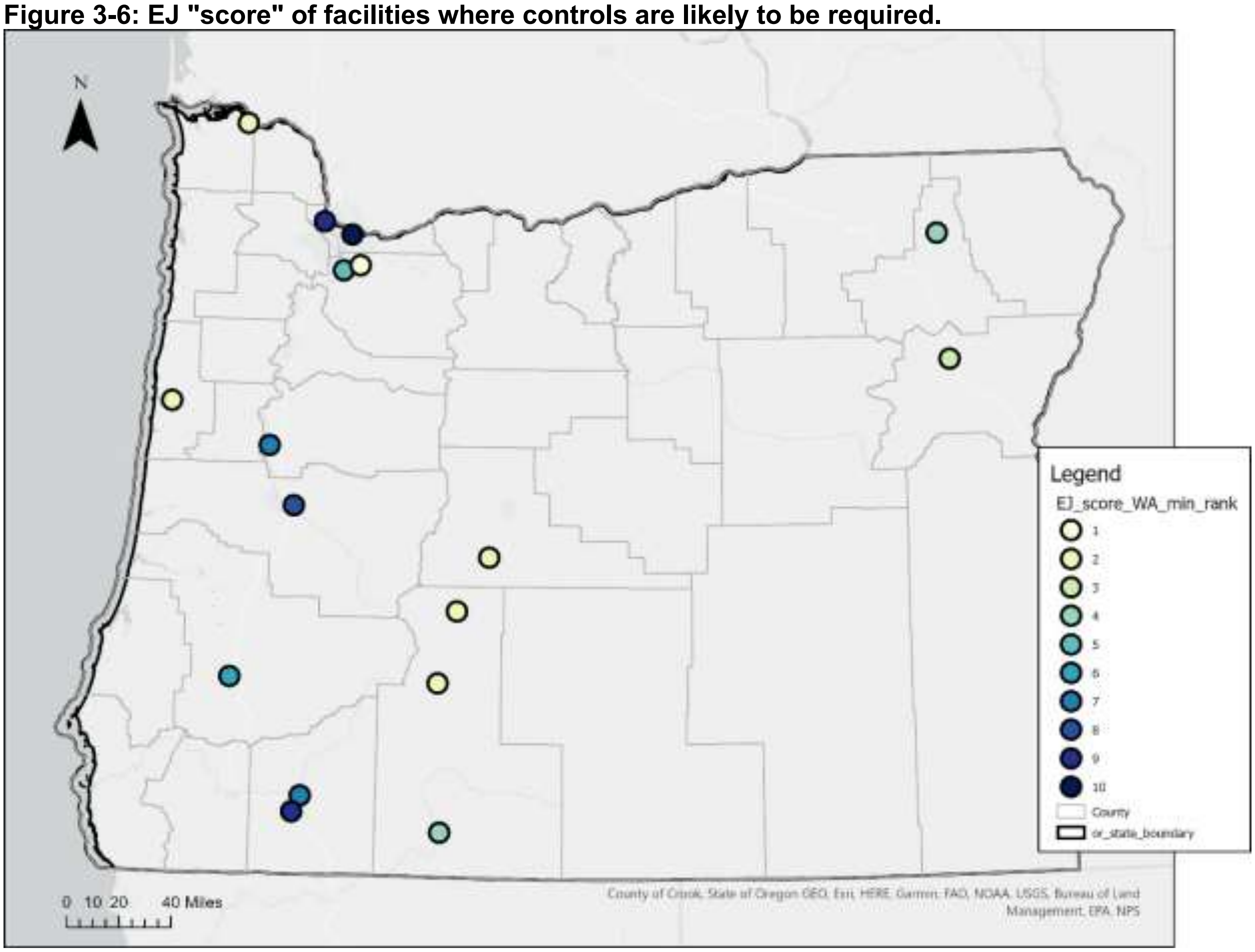


Table 3-6. Comparison of data inputs into CalEnviroScreen, WA Environmental Health Disparity Map, and MD EJSCREEN.

Similarities	Differences

• Calculate an **EJ Score** based on pollution burden x population characteristics
• **Pollution burden** is calculated from environmental exposures and environmental effects
• **Population characteristics** are calculated from sensitive populations and socioeconomic factors
• **Sensitive populations** = health-based data
• **Socioeconomic factors** = population data (mostly census based, may also come from other data sets)
	• **Specific data used in each category (see Appendix C)**
	• **Formula for calculating pollution burden and population characteristics**
	    • MD EJSCREEN: Uses average of factors (not weighted)
	    • WA EHDMP: Uses weighted averages
	• **How EJ Score is assigned after the composite score is calculated**
	    • MD EJSCREEN: Uses a score from 1-5 based on percentile rank (1 = 0-50%; 2 = 50-80%; 3 = 80-90%; 4 = 90-95%; 5 = 95-100%)
	    • WA EHDMP: Uses a score from 1-10 based on decile rank.

Figure 3-6: EJ "score" of facilities where controls are likely to be required.



3.6.2 Weight of Evidence Results

This weight of evidence approach indicated that controls are both environmentally beneficial and cost effective at many facilities evaluated by DEQ. Section 3.7 details the considerations made for each facility and what controls are required.

3.7 Facility-specific findings and results

This section summarizes the control analyses and the outcomes for each facility evaluated in Regional Haze Round 2. Table 3-7 lists the 32 facilities that DEQ initially determined exceeded the Q/d = 5 threshold. For each facility, DEQ has categorized its findings with a key. Keys 0 and 1 indicate facilities that did not undergo the FFA process because the facilities shut down or had recently undergone a control analysis, unrelated to the 2017 Regional Haze Rule. Key 2 Facilities did not need to undergo FFA because they agreed to lower their PSELs such that potential emissions would be lower than the Q/d threshold. For Key 3 facilities, the FFA outcome did not find any controls deemed cost effective, i.e. <$10,000/ton pollutant reduced. Key 4 facilities were those where DEQ's review of the FFAs found controls cost effective. The 17 Key 5 facilities are those for which DEQ requested a second round of more detailed FFA analysis and found controls to be cost effective.

Table 3-6 does not reflect final outcomes, but rather DEQ's findings based on FFA review. DEQ continued to accept information from and confer with facilities through August 9, 2021. In August 2021, using the authority provided by EQC's adoption of the revised Division 223 rules, DEQ issued orders to facilities to install pollution controls or otherwise reduce emissions of Round 2 Regional Haze pollutants. In some cases, DEQ determined that facilities had taken appropriate action to reduce their permitted emissions below the thresholds identified in Division 223 rules. In Appendix E, DEQ includes the orders and permits that document DEQ's Round 2 Regional Haze determinations for each regulated facility, with exceptions noted in the text of the following sections.

Table 3-7. Summary of DEQ findings for 32 facilities that initially screened into consideration for Round 2 emissions controls.

Facility ID	Facility Name	Actual Q/d	2017 PSEL Q/d	FFA key	Description
25-0016	PGE Boardman	38.24	116.21	0	No FFA. Facility shut down coal-fired operations, Carty GS, Q/d << 5.00
01-0029	Ash Grove Cement Company	18.54	38.47	1	No FFA, 2013 consent decree with EPA = max controls.
204402	Kingsford Manufacturing Company	8.38		2	No FFA - lowered PSEL to Q/d < 5.00
05-1849	Cascades Tissue Group: A Division of Cascades Holding US Inc.	3.02	63.72	2	No FFA - lowered PSEL to Q/d < 5.00.
15-0025	Timber Products Co. Limited Partnership	1.63	6.07	2	No FFA - lowered PSEL to Q/d < 5.00.
05-2520	PGE Beaver Plant/Port Westward I Plant	3.24	34.6	2	No FFA - Will lower PSEL to Q/d < 5.00 by 2025.
10-0078	Roseburg Forest Products - Riddle Plywood	2.1	5.29	2	No FFA, PSEL Q/d < 5.00
15-0073	Roseburg Forest Products - Medford MDF	2.91	8.84	2	No FFA, Q/d < 5.00

Facility ID	Facility Name	Actual Q/d	2017 PSEL Q/d	FFA key	Description
18-0003	Klamath Energy LLC – Klamath Cogeneration Proj	6.91	16.4	2	No FFA - lowered PSEL to Q/d < 5.00
08-0003	Pacific Wood Laminates, Inc.	8.29	12.5	3	FFA - no controls <$10K, no further action.
10-0045	Swanson Group Mfg. LLC	4.16	6.39	3	FFA - no controls <$10K, no further action.
12-0032	Ochoco Lumber Company	4.60	14.19	3	FFA - no controls <$10K, no further action.
18-0014	Columbia Forest Products, Inc.	4.1	7.75	3	FFA - no controls <$10K, no further action
18-0013	Collins Products, L.L.C.	4.78	10.82	3	FFA - no controls <$10K, no further action.
31-0002	Woodgrain Millwork LLC - Particleboard	13.32	18.41	3	FFA - no controls <$10K, no further action.
26-1876	Owens-Brockway Glass Container Inc.	10.86	21	4	FFA – controls cost effective.
18-0005	Gilchrist Forest Products	8.42	15.74	4	FFA – controls cost effective.
31-0006	Boise Cascade Wood Products, LLC - Elgin Complex	10.08	15.04	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
04-0004	Georgia Pacific - Wauna Mill	16.18	28.38	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
22-3501	Cascade Pacific Pulp, LLC - Halsey Pulp Mill	8.86	23.69	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
15-0004	Boise Cascade Wood Products, LLC - Medford	4.19	7.02	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
09-0084	Gas Transmission Northwest LLC - Compressor Station 12	2.33	14.13	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
18-0096	Gas Transmission Northwest LLC - Compressor Station 13	2.34	19.68	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
208850	International Paper - Springfield	16.51	67.24	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
21-0005	Georgia-Pacific – Toledo LLC	7.83	20.33	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
01-0038	Northwest Pipeline LLC - Baker Compressor Station	4.02	14.81	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
03-2729	Northwest Pipeline LLC - Oregon City Compressor Station	3.64	13.49	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
26-1865	EVRAZ Inc. NA	3.57	11.92	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
15-0159	Biomass One, L.P.	4.77	9.86	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
10-0025	Roseburg Forest Products - Dillard	19.07	30.67	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
18-0006	JELD-WEN	2.13	6.3	5	FFA - Step 2. More detailed controls analysis; controls cost effective.
03-2145	Willamette Falls Paper Company	3.79	26.46	5	FFA - Step 2. More detailed controls analysis; controls cost effective.

3.7.1 PGE Boardman (25-0016)

While PGE Boardman's emissions in 2017 would have screened the facility into four factor analysis based on the facility PSELs, and actual emissions, early communication in January 2020, confirmed that the facility was still on track to close operations by December 31, 2020. The closure of this facility, the last coal-fired power plant in Oregon, was a product of the first round of Regional Haze planning that took place in 2009-2010.

The facility officially closed its doors on October 15, 2020.[30] The remaining operations onsite are known as Carty Generating Station, and DEQ expects emissions to have a maximum Q/d of slightly over 1.00.

3.7.2 Ash Grove Cement Co, Durkee (01-0029)

Ash Grove Cement, Durkee plant (01-0029) recently underwent a stringent control analysis and DEQ determined that no additional controls required through Regional Haze Round 2 were likely to be effective or reasonable. To reach this determination, DEQ reviewed information the facility sent in early 2020, the facility's construction ACDP permit from 2017 (Permit No. 01-0029-CS-01), and the 2017 administrative amendment to the permit (Permit No. 01-0029-TV-01). In addition, DEQ took into account the actions that EPA took on Portland Cement companies.[31]

DEQ requires Ash Grove Cement to maintain existing controls to minimize visibility impairment and comply with this Regional Haze SIP. DEQ enforces existing controls through the facility's Title V permit and National Emission Standards for Hazardous Air Pollutants requirements. The provisions of the permit on which DEQ relies to enforce emission limits are described below.

Permit location: https://www.deq.state.or.us/AQPermitsonline/01-0029-TV-01_P_2020.PDF.

The facility's particulate matter emissions are controlled by a recently installed baghouse system in accordance with the 2018 Portland Cement NESHAP revisions for particulate matter for the kilns and the clinker cooler. The particulate limit is 0.07 lbs./ton clinker for the kiln and the clinker cooler, both continuously monitored by Continuous Parametric Monitoring Systems. Limits are based on a 30-day rolling average. Annual stack tests indicate compliance with the PM limit and the facility has passed all audits to ensure the PM CPMS is functioning.

The permit also limits SO_2 emissions to 0.4 lb./ton clinker on a 3-hour average. Compliance is determined by stack testing for SO_2 at least once every 2 years. NO_x emissions and emission factors have undergone recent substantive control reviews with EPA and are controlled by selective non-catalytic reaction with ammonia injection. The NO_x limit is 2.0 lb./ton clinker from the kiln monitored by Continuous Emission Monitoring System. All limits are on a 30-day rolling average. The 2.0 lb./ton clinker permit limit is being used as the emission factor to establish the PSEL in the draft permit. The permit requires the NO_x CEMS be operated and maintained in accordance with 40 CFR 60, Appendices B and F and DEQ's Continuous Monitoring Manual.

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[30] DEQ press release. October 15, 2020. "Closure of Boardman coal-fired plant a major milestone in reducing greenhouse gas emissions."
https://www.oregon.gov/newsroom/Pages/NewsDetail.aspx?newsid=53598 (Accessed 2/1/2021)
[31] U.S.A. vs. Ash Grove Cement Co. 2013. Consent Decree.
https://www.epa.gov/sites/production/files/documents/ashgrove-cd.pdf (Accessed 3/18/20)

These documents require quarterly audits which are performed by the permittee. The results of the audits are submitted to DEQ for review. No exceedances have been reported for a NO_x limit since the SNCR was installed. Per Permit No. 01-0029-CS-01, emissions reductions in PM, NO_x, and SO_2 resulting from compliance with the standards in that construction permit shall not be considered as a creditable contemporaneous emission decrease for the purposes of obtaining a netting credit under DEQ's PSD program.

Given the reasons outlined above, the unique circumstances of the facility of having recently gone through a control technology review through the NESHAPs and the global enforcement process, and per the Regional Haze guidelines issued by EPA, DEQ found that no further controls or analysis was necessary.

3.7.3 Facilities that lowered PSELs

DEQ offered facilities an option when their actual emissions had a screening value (Q/d) of less than the threshold of 5.00, but the screening value of the PSELs was greater than 5.00. Those facilities could lower PSELs and screen out of the FFA process. In some cases, facilities entered stipulated agreements and orders with DEQ that document PSEL reduction; in others PSEL reductions were documented in permit modifications or applications.

During consultation, the National Park Service expressed concern that these facilities might propose increasing PSELs under a future permitting action that would cause the facility to exceed the initial Q/d screening criteria. NPS stated that "facilities going through a permitting action may be allowed to focus only on the affected units and not required to take a facility-wide look at control options. This could, in effect, allow the source to piecemeal control technology determinations and restrict FLM opportunities for engagement." In response to that concern, DEQ asserts that under circumstances where a source proposes to increase emissions, including this scenario that NPS suggested, DEQ may reopen the issued permit to include requirements consistent with Oregon Regional Haze regulations and sources may be subject to reexamination of visibility impacts.

3.7.3.1 Kingsford Manufacturing Company (LRAPA #204402)

In a January 24, 2020 letter, Kingsford requested DEQ reevaluate the visibility impacts from the Springfield facility based on the PSELs contained in the Title V Operating Permit issued in August 2019 and confirm that the Springfield facility is not required to perform FFA for the Regional Haze program. In subsequent conversations with Kingsford and Lane Regional Air Protection Agency (LRAPA), DEQ stated that the Springfield facility could be excluded from conducting a four factor analysis for this round of the Regional Haze program if the Springfield facility was willing to accept a combined limitation on regional haze precursor PSELs and unassigned emissions such that a Q/d analysis based on the combined limitation resulted in a value of less than 5 at all Class 1 areas (see Table 3-8). In an April 16, 2020, email to DEQ and LRAPA, Kingsford agreed to a combined limitation on regional haze precursor PSELs and unassigned emissions of no more than 304 tons per year. Based on this agreement, DEQ concurred that Kingsford was not required to undergo FFA for their Springfield facility during this round of the Regional Haze program. DEQ required that Kingsford submit a permit modification application for the updated PSELs to LRAPA by August 1, 2020. The modified permit, reflecting the PSEL reduction is located here: https://www.lrapa.org/DocumentCenter/View/6032/Kingsford-204402---Permit-and-Addendums-No-1-and-2.

Table 3-8. Reduced PSELs for Kingsford Manufacturing (LRAPA #204402) to Q/d < 5.00.

	NO_x	SO_2	PM10	Total (Q)	d (km)	Q/d
PSEL (Aug 2019 Permit)	103	39	103	245	61.0	4.02
PSEL + Unassigned Emissions (Aug 2019 Permit)		549		549	61.0	9.00
PSEL + Unassigned Emissions (Proposed)		304		304	61.0	4.98

3.7.3.2 Cascade Tissue Group: A Division of Cascades Holding US, Inc. (05-1849)

Cascades Tissue Group communicated via a May 14, 2020, letter to DEQ that the facility had voluntarily agreed to lower PSELs for the St. Helens facility in April 2018, resulting in a Q/d value of 1.78. The facility stated they expected reduction of unassigned emissions and netting basis to occur in June 2021, rather than at the next permit renewal, which would take place in 2023 or 2024. In a stipulated agreement and final order signed August 18, 2021, included in Appendix E, the facility agreed that DEQ will set the PSEL for SO_2, PM10 and NO_x to 39, 14 and 103 tons per year, respectively, and set the unassigned emissions for each regional haze pollutant to zero.

3.7.3.3 Timber Products Co. (15-0025)

In a letter dated August 13, 2020, DEQ confirmed that the Timber Products Co. April 2020 permit renewal application had requested reduced PSELs below the screening threshold of Q/d = 5.00 (Q/d = 4.68; Table 3-9). Given the total emissions of the facility will be below the screening threshold of 5.00, DEQ agreed that this facility did not need to undergo FFA for Regional Haze Round 2. DEQ is drafting the permit renewal to reflect this PSEL reduction but the permit renewal was not complete at the time of this Regional Haze SIP submission.

Table 3-9. 2020 PSELs for Timber Products Co (15-0025)

	2016 PSEL	2020 PSEL
NO_x	162	154
PM10	159	85
SO_2	39	39 (PTE = 5)
Total (Q)	360	278
d	59.4 km	59.4 km
Q/d	6.07	4.68

3.7.3.4 PGE Beaver / Port Westward I (05-2520)

As PGE stated in their June 15, 2020, letter to DEQ, PGE committed to voluntarily reduce the PSELs of Regional Haze pollutants for the facility below the screening threshold of Q/d = 5.00. Given that the total emissions of the facility would be below the screening threshold of 5.00, and the facility's voluntary acceptance of lower limitation of their unassigned emissions, DEQ agreed that the facility did not need to undergo FFA for Regional Haze Round 2. In a Stipulated Agreement and Final Order signed August 10, 2021, included in Appendix E, PGE committed to reducing the PSELs for the facility on the following schedule:

- From August 1, 2021, to July 31, 2022, the Permittee's PSELs for the following pollutants are: 99 tons for PM10; 1,900 tons for NOx; and 99 tons for SO_2.

- From August 1, 2022, to July 31, 2023, the Permittee's PSELs for the following pollutants are: 99 tons for PM10; 1,542 tons for NOx; and 99 tons for SO_2.
- From August 1, 2023, to July 31, 2024, the Permittee's PSELs for the following pollutants are: 99 tons for PM10; 1,184 tons for NOx; and 99 tons for SO_2.
- From August 1, 2024, to July 31, 2025, the Permittee's PSELs for the following pollutants are: 99 tons for PM10; 826 tons for NOx; and 99 tons for SO_2.
- On August 1, 2025, the Permittee's PSELs for the following pollutants are: 99 tons for PM10; 436 tons for NOx; and 39 tons for SO_2.

3.7.3.5 Roseburg Forest Products – Riddle Plywood (10-0078)

Based on the letter from Roseburg Forest Products dated February 19, 2020, DEQ concurred that FFA was not required for this facility based on lowered PSELs in the July 2019 permit renewal (Table 3-10). The Title V permit sets federally enforceable permit limits. In addition, the 2019 permit renewal reduced unassigned emissions, so any increases in emissions above the netting basis by more than the Significant Emission Rates would trigger New Source Review or Prevention of Significant Deterioration permitting and analyses. DEQ has posted air quality permits on its webpage and Permit #10-0078-TV-01 may be accessed here: https://www.deq.state.or.us/AQPermitsonline/10-0078-TV-01_P_2019.PDF.

Table 3-10: Roseburg Forest Products - Riddle Plywood (10-0078) PSELs, July 2019 permit renewal Plant Site Emission Limits.

NO_x (tons/year)	SO_2 (tons/year)	PM10 (tons/year)	Total (Q) (tons/year)	d (km)	Q/d
144	39	108	291	68.9	4.2

3.7.3.6 Roseburg Forest Products – Medford MDF (15-0073)

In a letter dated June 2, 2020, DEQ concurred that FFA was not required for this facility based on lowered PSELs in the June 2017 permit renewal that reduced the Q/d to less than 5.

3.7.3.7 Klamath Energy LLC – Klamath Cogeneration Project (18-0003)

In a May 18, 2020, letter to DEQ, Klamath Energy LLC proposed that the Klamath Energy facility (18-0003) screen out of the Round 2 Regional Haze FFA process based on planned installations of ultra low-NO_x burners to combustors on the facility's combined cycle combustion turbines (emissions units CT1 and CT2) by May 2021 for CT2 and May 2022 for CT1. These upgrades would reduce the facility PSEL to 122 tons/year for PM10, SO_2, and NO_x combined, and reduce the Q/d to less than 5.00. Table 3-11 shows the Klamath Energy proposal below the 2017 PSELs DEQ used for initial Q/d screening and the 2017 actual emissions from the National Emissions Inventory.

DEQ agreed with the emissions reductions achievable through the installations of ultra low NO_x burners at the Klamath Energy facility and that the facility would not be required to go through the FFA process. Klamath Energy LLC submitted a permit modification application for the updated PSELs, as agreed, before August 1, 2020. DEQ issued the permit modification in December 2020, which now requires annual reporting of the combined rolling 12-month annual emissions for PM10, SO_2, and NOx, as tons per year. DEQ has posted air quality permits on its webpage and Permit #18-0003-TV-01 modification may be accessed here:

https://www.deq.state.or.us/AQPermitsonline/18-0003-TV-01_PM_2020_1.PDF. An administrative amendment to correct a typographical error is located here: https://www.deq.state.or.us/AQPermitsonline/18-0003-TV-01_AA_2021_1.PDF.

Table 3-11. Klamath Energy LLC's proposed PSEL reductions for Regional Haze.

Facility Emissions	NO_x	PM10	SO_2	Q	d	Q/d
2017 PSEL	314	48	39	401	24.45 km	16.4
2017 NEI Actual	143.0	19.6	6.4	169	24.45 km	6.91
Klamath Energy proposal				122 combined	24.45 km	4.99

3.7.4 Facilities for which no controls were cost-effective

Six facilities completed the FFA and after adjustment for interest rate and remaining useful life, the costs of control were significantly above $10,000/ton. DEQ's review found no emissions units and control devices at these facilities met the criteria for further analysis. The FFAs are included in Appendix F.

DEQ requires each of these facilities to maintain existing controls to minimize visibility impairment and comply with this Regional Haze SIP. DEQ enforces existing controls through each facility's Title V or Air Contaminant Discharge permit and National Emission Standards for Hazardous Air Pollutants. For each facility listed below, DEQ provides the permit number, where to find that permit and the provisions of the permit on which DEQ relies to enforce emission limits.

Collins Products, L.L.C.
Permit number: 18-0013-TV-01
Permit location: https://www.deq.state.or.us/AQPermitsonline/18-0013-TV-01_P_2015.PDF

Controls to maintain: biofilter, bag filter, fugitive control plan (see Permit Condition 3 Table – Emissions Unit and Pollution Control Device Identification)

Emission Limits and Standards. Testing, Monitoring and Recordkeeping Requirements: Table 3-12 to Table 3-16 summarize the emission limits, standards, testing, monitoring and recordkeeping requirements within permit number 18-0013-TV-01. Permit sections 71 – 77 contain general reporting requirements.

Table 3-12: Facility wide emission limits, standards and monitoring requirements for Collins Products

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Monitoring Requirement	Monitoring Condition
340-208-0210(2)	4	Fugitive emissions	Fugitive Control Plan/Minimize Emissions	Visual Survey	8
340-240-0520	6				
340-234-0520(1)(a) & 234-0530(1)(a)]	5				
ACDP Condition 16	7				
340-240-0530	9	Operation and Maintenance	O&M Plan	Review plan periodically	10
340-208-0300	11	Air contaminants	Not cause a nuisance	Complaint investigation	13
340-208-0450	12	PM >250µ	No observable deposition off site	Complaint investigation	13
340-228-0110(1)	14	ASTM Grade 1 distillate fuel oil	<0.3% Sulfur by weight	Vendor certificate or analysis	15 & 16
340-228-0110(2)		ASTM Grade 2 distillate fuel oil and used oil	<0.5% Sulfur by weight		
40 CFR Part 68	17	Risk management	Risk management plan	NA	17
40 CFR Part 63, Ssubpart DDDD	18	General compliance provisions			

Table 3-13: Particle board emission limits, standards and monitoring requirements for Collins Products

Emission Unit	Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Monitoring Condition
PB01-PB10, PB12	340-208-0110(2) and 340-240-0510 (1)	19	Visible Emissions	20% opacity, 3 min. aggregate in 60 minutes	20
PB01-PB10, PB12	340-226-0210(1)(b)	21	PM	0.1 gr/dscf, avg. of 3 test runs	20 and 22
PB01-PB04, PB06-PB10, PB12	340-234-0520(2)(a)	23	PM	3 lbs/1,000 ft^2, 3/4"	24
PB01 and PB02	40 CFR 63.2240	25	HAP	Compliance options	28
	40 CFR 63.2240(b)	26	HAP	Capture efficiency	28
	40 CFR 63.2240	29	HAP	Biofilter temperature operating limit	32
PB05	40 CFR 63.2241(a)	30	HAP	Dryer inlet temperature and furnish moisture content work practice requirements	32
PB06	40 CFR 63.2240(a)	27	HAP	0.26 lb/ODT	31-33

Table 3-14: Particle board test methods for Collins Products.

Emissions Unit	Test Method	Frequency
PB01/PB45 Biofilter (press area and unloader)	Modified EPA Method 9	Weekly
PB03 (board side and end trim saws), PB04 (board cooler vents), PB05 (core dryers), PB06 (surface dryers), PB07 (cyclone PB22), PB08 (cyclone PB24), PB09 (cyclones with primary filters), PB10 (cyclones with secondary filters), PB12 (secondary screen with primary filter)	Modified EPA Method 9	At least once during each semi-annual compliance certification period with at least 30 days between observations

Table 3-15: Hard board emission limits, standards and monitoring requirements for Collins Products

EU ID	Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Monitoring Condition
HB01-HB04, HB08-HB17	340-208-0110(2) and 340-240-0510(1)	34	Visible Emissions	20% opacity, 3 min. aggregate in 60 minutes	35
HB01-HB04, HB08-HB17	340-226-0210(1)(b)	36	PM	0.1 gr/dscf, avg. of 3 test runs	35, 37, 38, 39, 40
HB01-HB16	340-234-0530(2)(b)(B)	41	PM	1.4 lbs/1,000 ft2, 1/8"	42
HB01-HB04 and HB16	40 CFR 63.2240	43	HAP	Compliance options	45
	40 CFR 63.2240(b)	44	HAP	Capture efficiency	45
	40 CFR 63-2240	46	HAP	Biofilter temperature operating limit	49
HB08	40 CFR 63.2240	43	HAP	Compliance options	45
	40 CFR 63-2240	47	HAP	RCO minimum operating temperature	49

Table 3-16: Hard board test methods for Collins Products

Emissions Unit	Test Method	Frequency
HB01 – HB04 and HB16 (HB50 biofilter - existing and future defibrators, press, loader, and unloader)	Modified EPA Method 9	Weekly
HB09 (bake oven/dehumidifier roof vents), HB10 (Cyclone HB7), HB12 (cyclones HB8-12, 16, 18), HB14 (cyclones HB23, 31, 32, 44), HB15 (cyclone HB27), HB17 (coating ovens)	Modified EPA Method 9	At least once during each semi-annual compliance certification period with at least 30 days between observations

<u>Columbia Forest Products, Inc.</u>
Permit number: 18-0014-RV-01
Permit location: https://www.deq.state.or.us/AQPermitsonline/18-0014-TV-01_P_2017.PDF

Controls to maintain: multiclone, baghouse (see Permit Condition 3 Table 1 – Emissions Unit and Pollution Control Device Identification)

Emission Limits and Standards. Testing, Monitoring and Recordkeeping Requirements: **Error! Reference source not found.** to Table 3-19 summarize the emission limits, standards, testing, monitoring and recordkeeping requirements within permit number 18-0014-TV-01. Permit sections 58 – 66 contain additional recordkeeping and reporting requirements.

Table 3-17: Summary of facility wide emission limits and standards for Columbia Forest Products

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Monitoring Requirement	Monitoring Condition
340-208-0210(2)	4	Fugitive Emissions	Minimize	Fugitive Dust Control Plan, observations, and recordkeeping	40 & 41
340-208-0300	5	Air Contaminants	Not cause a nuisance	Complaint investigation	42
340-208-0450	6	PM >250µ	No observable deposition off site	Complaint investigation	42
40 CFR Part 68	7	Risk Management	Risk management plan	NA	NA

Table 3-18: Emission unit specific emission limits and standards for Columbia Forest Products.

EU ID	Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Monitoring Requirement	Monitoring Condition
BLR-S and BLR-N	340-208-0110(2)(a) and (5)	8	Visible Emissions	40% opacity, 6-minute block average through 12/31/2019[a]	VE periodic monitoring	43
	340-228-0210(2)(a)(B) and (C)	9	PM	0.24 gr/dscf @ 12% CO_2 through 12/31/2019[b]	Periodic VE observations and O&M	43, 44 and 45
	40 CFR Part 63, Subpart JJJJJJ	10 - 13	HAPs	Biennial Tune-up	Biennial Tune-up Records	12
V-N	340-234-0510(1)(b)	14	VE and PM	10% daily average operating opacity	VE periodic monitoring	46
	340-234-0510(1)(e)	15	VE and PM	Highest and Best	Periodic VE observations and O&M	47
	340-234-0510(1)(f)	16	PM	Concealing Emissions	Periodic VE observations and O&M	47
	340-226-0210(2)(b)(B)	17	PM	0.14 gr/dscf	ST periodic monitoring	46 and 47
PV	340-208-0110(2)(a) and (4)	18	Visible Emissions	20% opacity, 6-minute block average	VE periodic monitoring	48
	340-226-0210(2)(b)(A)	19	PM	0.10 gr/dscf	ST periodic monitoring	48
MH	340-208-0110(2)(a) and (4)	18	Visible Emissions	20% opacity, 6-minute block average	VE periodic monitoring	49
	340-226-0210(2)(b)(B)	19	PM	0.14 gr/dscf	ST periodic monitoring	49 and 50
PV and MH	340-234-0510(2)(a)	19	PM	56.25 lb/hr	Periodic VE observations, equipment I&M and material throughput	48, 49, 50 and 51
EU ID	**Applicable Requirement**	**Condition Number**	**Pollutant/ Parameter**	**Limit/Standard**	**Monitoring Requirement**	**Monitoring Condition**
NG1	340-208-0110(5)	22	Visible Emissions	20% opacity, 6-minute block average	VE periodic monitoring	52
	340-226-0210(2)(b)(B)	23	PM	0.14 gr/dscf avg. of 3 test runs	Periodic VE observations and O&M	52

(a) Boiler limits (BLR-S & BLR-N) becomes 20% opacity on and after January 1, 2020.

(b) Boiler limit (BLR-S) becomes 0.15 gr/dscf on and after January 1, 2020. Boiler limit (BLR-N) becomes 0.20 gr/dscf on and after January 1, 2020, if operated 870 hours or less in a calendar year.

Table 3-19: Compliance source testing methods for Columbia Forest Products.

Emissions Unit	Pollutant	Test Method
V-N	PM	Oregon Method 7
PV	PM	Oregon Method 7
MH	PM	Oregon Method 5 or 8
NG1	Visible Emissions (opacity)	EPA Method 9
NG1	PM	Oregon Method 5

Ochoco Lumber Company (12-0032)
Permit number: 12-0032-ST-01
Permit location https://www.deq.state.or.us/AQPermitsonline/12-0032-ST-01_P_2019.PDF:

Controls to maintain: multiclone on boilers 1 and 2, electrostatic precipitator on boiler 3.

Emission Limits and Standards, Testing, Monitoring, Recordkeeping and Reporting Requirements:
Within permit number 12-0032-ST-01, Section 1.0 sets general emission standards and limits for visible, PM, fugitive and nuisance emissions. Section 1.6 specifies that the permittee must operate and maintain air pollution controls devices and emission reduction processes at the highest reasonable efficiency and effectiveness to minimize emissions. Section 2.0 sets specific performance and emission standards for the boilers, including associated reporting. Section 4.0 establishes required compliance demonstration at source testing, including monitoring requirements. Sections 5.0 and 6.0 establish recordkeeping and reporting requirements, respectively.

Pacific Wood Laminates, Inc.
Permit number: 08-0003-TV-01
Permit location: https://www.deq.state.or.us/AQPermitsonline/08-0003-TV-01_P_2019.PDF.

Controls to maintain: wet scrubber, baghouses 1 – 4 (see Permit Condition 3, Table 1)

Emission Limits and Standards, Testing, Monitoring, Recordkeeping and Reporting Requirements:
Table 3-20 through Table 3-27 summarize the emission limits, standards, testing, monitoring and recordkeeping requirements within permit number 08-0003-TV-01. Permit section 57 establishes requirements for visible emissions monitoring for boiler PH2, veneer dryers, plywood presses and conveyors. Sections 58 - 69 contain additional monitoring, recordkeeping and reporting requirements.

Table 3-20: Facility wide emission limits and standards for Pacific Wood Laminates, Inc.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Monitoring Requirement	Monitoring Condition
340-208-0210(1-2)	4	Fugitive emissions	Minimize	Fugitive emission survey	5
340-208-0300	6	Air contaminants	No nuisance	Complaint Investigation	8
340-208-0450	7	PM >250μ	No fallout	Complaint Investigation	8
340-234-0510(2)	9	Particulate Matter	34.7 pounds/hour, daily basis	Recordkeeping	10
40 CFR Part 68	11	Risk management	Risk management plan	NA – below threshold	NA

Table 3-21: Summary of requirements for emission unit boiler PH2 at Pacific Wood Laminates, Inc.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(6)	12	Visible emissions	20% opacity	6-minute block average	NA	13
340-228-0210(2)(b)(A)	14	PM	0.10 gr/dscf @ 12% CO_2	Avg. of 3 test runs	19	15-18
40 CFR Part 63 Subpart JJJJJJ	20	HAPs	Tune-up & one time energy assessment	Biennial tune-up	20.a, 20.b	21-25

Table 3-22: Emission test methods for emission unit boiler PH@ at Pacific Wood Laminates, Inc.

PM	ODEQ Methods 1-5
NOx	EPA Method 7E
CO	EPA Method 10
Opacity	EPA Method 9

Table 3-23: Summary of requirements for emission units veneer dryers A, B and C and Pacific Wood Laminates, Inc.

Applicable Requirement	Requirement Condition Number	Pollutant/Parameter	Limit/Standard	Monitoring Requirement	Monitoring Condition Number
340-234-0510(1)	26	Visible emissions	10% average, opacity 20% maximum opacity as 6 min. block average	VE, I & M	27, 32
340-226-0210(2)(b)	28	PM	0.10 gr/dscf (avg. of 3 test runs)	Monthly I & M, source test, CAM	32-37
340-226-0310	29	PM	Table 1 OAR 340 Division 226	Monthly I & M, source test, CAM	32-37
340-234-0510(1)(e) & (g)	30	Air contaminant emissions	Minimize with highest and best operation	Monthly I & M	32
340-234-0510(1)(f)	31	Air contaminant emissions	Concealing emissions prohibited	Yearly I & M	33

Table 3-24: Emission test methods for emission units veneer dryers A, B and C and Pacific Wood Laminates, Inc.

Location: RTO/RCO Exhaust Duct

PM	ODEQ Method 5
NO_x	EPA Method 7E
CO	EPA Method 10
Opacity	EPA Method 9
VOC	EPA Method 25A

Location: RTO/RCO Inlet Duct

Flow	EPA Methods 1-4
VOCs	EPA Method 25A
Methanol and formaldehyde	NCASI Method 98.01 (or equivalent)

Table 3-25: Summary of requirements for emission unit plywood presses, 1, 2, 3 and 4 at Pacific Wood Laminates, Inc.

Applicable Requirement	Requirement Condition Number	Pollutant/Parameter	Limit/Standard	Monitoring Requirement	Monitoring Condition Number
340-208-0110(4)	38.a	Visible emissions from Press 1,3, & 4	20% opacity as 6-minute block average	VE	40
340-208-0110(3)(a)	38.b	Visible emissions from Press 2	40% opacity as 6 min. block avg. until December 31, 2019; 20% opacity on or after January 1, 2020	VE	40
340-226-0210(2)(c)	39.a	PM	0.10 gr/dscf (avg. of 3 test runs) for Press 4	VE, ST	40, 41
340-226-0210(2)(b)(B)	39.b	PM	0.14 gr/dscf (avg. of 3 test runs) for Press 1 and 3	VE, ST	40, 41
340-226-0210(2)(a)(B)	39.c	PM	0.24 gr/dscf through 12/31/19, then 0.15 gr/dscf (avg. of 3 test runs) for Press 2	VE, ST	40, 41

Table 3-26: Emission test methods for emission unit plywood presses, 1, 2, 3 and 4 at Pacific Wood Laminates, Inc.

Location: Press Exhaust Duct

Stack Flow and conditions	EPA Methods 1-4
PM	ODEQ Method 5
Opacity	EPA Method 9
VOC	EPA Method 25A
Formaldehyde and Methanol	NCASI Method 98.01
TTE	EPA Method 204

Table 3-27: Summary of requirements for emission units material transport and pneumatic conveyors at Pacific Wood Laminates, Inc.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(3) & (4)	42	Visible emissions	20% opacity or 40% opacity thru 12/31/19, then 20% opacity	6-minute block average	NA	45
340-226-0210(1)(b)	43	PM	0.10- 0.24 gr/dscf, see condition	Avg. of 3 test runs	NA	46, 47
340-226-0310	44	PM	See Table 1	Avg. of 3 test runs	NA	46, 47

Swanson Group Mfg. LLC
Permit number: 10-0045-TV-01
Permit location: https://www.deq.state.or.us/AQPermitsonline/10-0045-TV-01_P_2017.PDF.

Controls to maintain: multiclones, electrostatic precipitator, baghouse (see Permit Condition 4, Table 1 – Emission Units).

Emission Limits and Standards, Testing, Monitoring, Recordkeeping and Reporting Requirements:
Table 3-28 through Table 3-32 summarize the emission limits, standards, testing, monitoring and recordkeeping requirements within permit number 10-0045-TV-01. Sections 51 – 62 contain additional monitoring, recordkeeping and reporting requirements.

Table 3-28: Summary of facility wide emission limits and standards for Swanson Group Mfg.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0210	5	Fugitive emissions	Minimize	NA	NA	8
340-208-0300	6	Air contaminants	No nuisance	NA	NA	8
340-208-0450	7	PM >250µ	No fallout	NA	NA	8
40 CFR Part 68	9	Risk management	Risk management plan	NA	NA	9

Table 3-29: Summary of requirements for emission unit hog fuel boiler at Swanson Group Mfg.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(5)	10	Visible emissions	40%/20% opacity	6-minute block average	NA	11
340-228-0210(2)(a)(A)	12	PM	0.10 gr/dscf @ 12% CO_2	Avg. of 3 test runs	13	14-18
40 CFR Part 63 Subpart JJJJJJ	19 and Part 2	HAP	Operate boiler in compliance with requirements of JJJJJJ	NA	NA	Part 2

Table 3-30: Summary of requirements for veneer dryer emissions units at Swanson Group Mfg.

Applicable Requirement	Requirement Condition Number	Pollutant/Parameter	Limit/Standard	Monitoring Requirement	Monitoring Condition Number
340-234-0510(1)(a) and (b)	20	Visible emissions	10% average opacity, 20% maximum opacity as 6 min. avg.	Quarterly VE tests	20.c
340-226-0210(2)(a)(A)	21	PM---Dryer 1	0.10 gr/dscf (avg. of 3 test runs)	RTO temperature	25
340-226-0210(2)(a)(B)	22	PM---Dryer 2	0.24/0.15 gr/dscf (avg. of 3 test runs)	RTO temperature	25
340-226-0210(2)(b)(B)	23	PM---Dryer 3	0.14 gr/dscf (avg. of 3 test runs)	RTO temperature	25
340-226-0310	24	PM	Table 1 OAR 340 Division 226	RTO temperature	25
340-234-0510(1)(e) & (g)	26.a	Air contaminant emissions	Minimize with highest and best operation	Monthly I & M	26.c
340-234-0510(1)(f)	26.b	Air contaminant emissions	Concealing emissions prohibited	Yearly I & M	26.d

Table 3-31: Summary of requirements for presses 1, 2 and 3 emission units at Swanson Group Mfg.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(3)(b); 340-208-0010(4)	29	Visible emissions---Presses 1 & 2; Press 3	20% opacity	6-minute block average	NA	33
340-226-0210(2)(a)(B)	30	PM---Presses 1 & 2	0.24/0.15 gr/dscf	Avg. of 3 test runs	NA	33
340-226-0210(2)(b)(B)	31	PM---Press 3	0.14 gr/dscf	Avg. of 3 test runs	NA	33
340-226-0310	32	PM	Table 1 OAR 340 Division 226	Avg. of 3 test runs	NA	33

Table 3-32: Summary of requirements for pneumatic conveyors, sander, presses, and material handlers.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit /Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(4)	34	Visible emissions	20% opacity	6-minute block average	NA	35
340-226-0210(2)(b)(B)	36	PM---4CON &1SAN	0.14 gr/dscf	Average of 3 test runs	NA	38
340-226-0310	37	PM	Process weight	Average of 3 test runs	NA	38
340-234-510(2)(a)	38	PM	33.0 lb/hr from PLY	24 hours	NA	40

Woodgrain Millwork LLC – Particleboard
Permit number: 31-0002-TV-01
Permit location: https://www.deq.state.or.us/AQPermitsonline/31-0002-TV-01_P_2021.PDF.

Controls to maintain: multiple baghouses, dry and wet electrostatic precipitators.

Emission Limits and Standards, Testing, Monitoring, Recordkeeping and Reporting Requirements: Table 3-33 through Table 3-43 summarize the emission limits, standards, testing, monitoring and recordkeeping requirements within permit number 31-0002-TV-01. Sections 81 – 92 contain additional monitoring, recordkeeping and reporting requirements.

Table 3-33: Facility wide requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
OAR 340-208-0210(1), 340-234-0520(1), 1/19/95 ACDP Condition 7	4	Fugitive Emissions	Minimize	NA	NA	5
340-208-0300	6	Nuisance	No Nuisance	NA	NA	8
340-208-0450	7	PM >250μ	No Fallout	NA	NA	8
340-228-0110(2)	9	#2 Fuel Oil Sulfur Content	≤0.5% Sulfur by Weight	Each Shipment	NA	10
40 CFR Part 68	11	Risk Management	Risk Management Plan	NA	NA	11

Table 3-34: Emission unit boiler 1 requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(3)(b)	12	Visible Emissions	20% Opacity	6-Minute Block Average	14	15
340-228-0210(2)(a)(B)(ii)	13	PM	0.15 gr/dscf @ 50% Excess Air	Avg. of 3 Test Runs	14	15
40 CFR 63.7540(a)(10)	16	Work Practice	Annual Tune-Up	NA	NA	17.c

Table 3-35: Emission unit boiler 2 requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(6)	18	Visible Emissions	20% Opacity	6-minute Block Average	NA	27
340-228-0210(2)(b)	19	PM	0.10 gr/dscf @ 12% CO_2	Avg. of 3 Test Runs	23	20, 21, 24
40 CFR 63.7500(a)(1)	22.a.i or	Filterable Particulate or	0.051 lb/MMBtu Heat Input, or 0.052 lb/MMBtu Steam Output	Avg. of 3 Test Runs	23	20, 22.f, 25, 26
	22.a.ii	Total Selected Metals	6.5E-03 lb/MMBtu Heat Input, or 0.052 lb/MMBtu Steam Output	Avg. of 3 Test Runs	23	26, 29
40 CFR 63.7500(a)(1)	22.b	Carbon Monoxide	2,400 ppmv, dry @ 3% O_2, or 1.9 lb/MMBtu Steam Output	Avg. of 3 Test Runs	23	22.f, 24
	22.c	Mercury	5.7E-06 lb/MMBtu Heat Input, or 6.4E-06 lb/MMBtu Steam Output	Avg. of 3 Test Runs	23	26, 29
	22.d	HCl	0.022 lb/MMBtu Heat Input, or 0.025 lb/MMBtu Steam Output	Avg. of 3 Test Runs	23	26, 29
	22.f	Work Practice	Tune-Up	Annually	NA	30.g
40 CFR 63. 7500(a)(2)	25	Visible Emissions	10% Opacity	Daily Block Average	23	27
40 CFR 63.7500(f)	28	Startup/ Shutdown	Fuel Limitations During Startup, CMS Operating	NA	NA	28

Table 3-36: Boiler 2 testing requirements for Woodgrain Millwork.

Pollutant/Parameter	Test Method	Frequency	Purpose
Particulate (filterable) Particulate (total)	EPA Method 5 or 17 ODEQ Method 5	Annually Once during permit term	Compliance testing EF verification
Opacity	COMS and/or EPA Method 9	Continuous for COMS M9 during PM test	Compliance testing
NO_x	EPA Method 7E	Once during permit term	EF verification
CO	EPA Method 10	Annually	Compliance testing EF verification
Total Selected Metals (TSM)	EPA Method 29	Annually	Compliance testing
Mercury	EPA Method 29, 30A, 30B, 101A, or ASTM D6784	Annually	Compliance testing
Hydrogen Chloride (HCl)	EPA Method 26 or 26A	Annually	Compliance testing

Table 3-37: Emission unit green furnish dryer requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(4)	31	Visible Emissions	20% Opacity	6-Minute Block Bverage	NA	35, 37
340-228-0210(2)(b)(B)	32	PM	0.14 gr/dscf @ 12% CO_2	Avg. of 3 Test Runs	34	35, 37
40 CFR 63.2240(b) Table 1B-option 3	33	Methanol	90% Reduction	Avg. of 3 Test Runs	NA	36, 37

Table 3-38: Emission unit line 1 and 2 dryers requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(3)(b)	40	Visible Emissions	20% opacity	6-minute block average	43	44, 46
340-226-0210(2)(a)(B)(ii)	41	PM	0.15 gr/dscf	avg. of 3 test runs	43	44, 46
40 CFR 63.2241(a) Table 3-Item 1	42	Inlet Moisture, Temperature	≤30% (by weight, dry), ≤600°F	24-hour block	NA	45

Table 3-39: Emission unit line 1 and 2 presses/thermal catalytic oxidizers requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(3)(b)	48	Visible Emissions	20% Opacity	6-Minute Block Average	NA	52, 53
340-226-0210(2)(a)(A)	49	PM	0.10 gr/dscf	Avg. of 3 Test Runs	51	52, 53
40 CFR 63.2240(b) Table 1B-option 3	50	Methanol	90% Reduction	Avg. of 3 Test Runs	51	52, 53

Table 3-40: Emission unit board cooler requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(3)(b)	55	Visible Emissions	20% Opacity	6-minute block average	57	58
340-226-0210(2)(a)(B)(ii)	56	PM	0.15 gr/dscf	Avg. of 3 test runs	57	58

Table 3-41: Emission unit uncontrolled cyclone requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(3)(b)	60	Visible Emissions	20% Opacity	6-minute block average	62	63
340-226-0210(2)(a)(B)(ii)	61	PM	0.15 gr/dscf	Avg. of 3 test runs	62	63

Table 3-42: Emission unit material handling cyclone requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0110(3)(b)	65	Visible Emissions	20% Opacity	6-minute block average	67	68, 69
340-226-0210(2)(a)(B)(ii)	66.a	PM	0.15 gr/dscf for C11, C12, C16-22, C31, C32 and C36	Avg. of 3 test runs	67	68, 69
340-226-0210(2)(b)(B)	66.b	PM	0.14 gr/dscf for C1-C3, C25-C28, C37-C39, C42, C43, C47, C48, and C50-C55	avg. of 3 test runs	67	68, 69

Table 3-43: Emission unit particle board manufacturing requirements for Woodgrain Millwork.

Applicable Requirement	Condition Number	Pollutant/ Parameter	Limit/ Standard	Averaging Time	Testing Condition	Monitoring Condition
340-234-0520(2)	71	PM	117 lb/hr	24-hour period divided by 24	NA	72

3.7.5 Facilities where DEQ found controls cost effective

In two cases, DEQ found controls cost effective based on the facility-submitted FFAs. For the remaining 15 facilities, DEQ requested a second analysis of control cost effectiveness. DEQ continued to confer with and consider information these facilities provided through August 9, 2021. On and after August 9, 2021, DEQ either entered stipulated agreements and orders with facilities or issued orders to facilities to install controls or otherwise reduce Round 2 regional haze pollutant emissions.

3.7.5.1 Owens-Brockway (26-1876)

In a letter dated October 27, 2020, DEQ concurred with Owens-Brockway's findings in FFA submitted on June 12, 2020, that costs of installing controls were reasonable. Specifically, DEQ concurred with the findings that combined control of NO_x, SO_2 and PM by catalytic ceramic filters is cost-feasible for the facility's glass-melting furnaces A and D.

Owens-Brockway informed DEQ by an April 27, 2021, letter that the facility intended to shut down Furnace A permanently and request Furnace A and its emissions units' removal from their Title V permit. Rather than install controls, Owens-Brockway chose the alternative compliance option to lower PSELs. On August 8, 2021, Owens Brockway entered a stipulated agreement and order with DEQ to accept federally enforceable reductions of combined PSELs for Round 2 Regional Haze pollutants to bring the facilities Q/d below 5.00.

The final order, included in Appendix E, requires the following and contains other requirements and provisions:

- The permittee shall not operate Furnace A
- On and after January 1, 2022, the permittee shall comply with the following PSELs, which apply to each 12 consecutive calendar month period after that date: 55 tons/year PM10, 137 tons/year NO_x, and 108 tons/year SO_2.
- Unassigned emissions shall be set to 0.
- The netting basis for Furnace A, Furnace B, and Furnace C shall be removed from the total netting basis of the facility.
- On July 21, 2025, the permittee's PSELs for the following pollutants are: 274.95 tons/year PM10 + NO_x + SO_2, which results in a Q/d = 4.99.

DEQ will enforce compliance with the PSEL reductions through the facility's Title V permit monitoring, recordkeeping and reporting requirements. DEQ submits the following sections of permit number 26-1876-TV-01 with this Regional Haze SIP for approval:

32. Annual PSEL Requirement
33. Monitor and Record: for PM10, SO_2, and NO_x
34. General Testing Requirement
35. EU4 Emission Factor Verification Testing Requirements: for PM10, NO_x, SO_2

36 – 38. General Monitoring and Recordkeeping Requirements
39 – 42. General Recordkeeping Requirements
43 – 46. General Reporting Requirements
47 – 48. Semi-annual and Annual Reports

3.7.5.2 Gilchrist Forest Products

In a letter dated September 11, 2020, Interfor US agreed that installation of an Electrostatic Precipitator on boilers B-1 and B-2 would be cost-effective, and provided a letter from a boiler vendor indicating that retrofitting those boilers with Selective Non-Catalytic Reduction was not technically feasible. Based on the information submitted, DEQ concurred. On June 8, 2021, Gilchrist Forest Products submitted a Notice to Construct to install the ESP on boilers B-1 and B-2. After ESP installation, Gilchrist PSELs will remain 99 tons/year NO_x and 39 tons/year SO_2. Their PM10 PSEL will be reduced to about 52 tons/year, depending on the control efficiency of the new ESP, which would represent a reduction of 120 tons/year from current PSELs. The Notice to Construct is included in Appendix E. As of late January 2022, the ESP has been installed and the boiler restarted, but the facility is working to resolve some operational issues that are weather dependent. Gilchrist has one year from installation submit a permit application for a modification. Once the facility submits the permit modification application, DEQ will incorporate permit conditions requiring operation of the ESP into the Title V permit.

3.7.5.3 Boise Cascade Wood Products, LLC - Elgin Complex (31-0006)

In a letter dated January 21, 2021, DEQ notified Boise Cascade Wood Products of its preliminary determination that their Elgin facility would likely be required to install Selective Catalytic Reduction on Boilers 1 and 2. Boise Cascade provided DEQ a technical memo dated April 19, 2021, in which Boise Cascade's consultant concluded that SCR was not technically feasible on boilers at the Elgin facility. DEQ did not agree that SCR was infeasible; however, DEQ did accept the facility's argument that the feasibility was unknown due to the potential for catalyst fouling. Boise Cascade also provided DEQ a second technical memo dated May 10, 2021, in which a vendor provided their recommendations regarding the feasibility and effectiveness of other NO_x reduction technologies including low oxygen operation, air staging, flue gas recirculation natural gas co-firing, and steam or water injection.

Rather than install SCR, Boise Cascade proposed an alternative compliance option to accept federally enforceable requirements to install and continually operate combustion controls, monitoring equipment and accept emission limitations to reduce Round 2 regional haze pollutants from the Elgin facility. Based on an enforceable 15% emissions reduction or equivalent PSEL reductions, DEQ accepted this proposal. On August 12, 2021, Boise Cascade entered into a stipulated agreement and order with DEQ. The final order, included in Appendix E, requires the following and contains other requirements and provisions:

- On and after July 31, 2022, the permittee's PSELs for SO_2 are 17.1 tons/year
- Within three months of the signed order, permittee shall install a Continuous Emission Monitoring System on Boiler 1 and Boiler 2 to measure NO_x emissions.
- By July 31, 2023, the permittee shall begin installation of combustion improvement project(s) designed to achieve emissions reductions of NO_x from Boiler 1 and Boiler 2 by 15%, and permittee shall begin monitoring NO_x emissions using the CEMS to determine actual NO_x emission reductions achieved by controls.
- If initial boiler combustion improvement project(s) fail to achieve a minimum 15% NO_x reduction, the permittee may implement additional combustion improvement projects to achieve 15% NO_x reduction or accept PSEL reductions.
- By December 31, 2025, the permittee shall submit 12 months of CEMS data to DEQ demonstrating the NO_x emission reductions achieved by combustion controls, and shall propose a NO_x limit based on the achieved reductions.

- If combustion controls fail to achieve 15% NO_x reduction, the permittee must reduce PSEL ($PM10+NO_x+SO_2$) to a level that would achieve a Q/d commensurate with a 15% Boiler NO_x reduction.
- On and after March 31, 2026, the permittee must comply with emission limits and the PSEL established under the conditions listed in the order.

DEQ will enforce compliance with the PSEL reductions through the facility's Title V permit monitoring, recordkeeping and reporting requirements. DEQ submits the following conditions of permit number 31-0006-TV-01 with this Regional Haze SIP for approval:

56. Monitoring Requirement, 56a.Emission Calculation, Table 6 (Emission Factors) for Boilers 1 and 2 for PM10, SO_2, NO_x
59 - 61. General Monitoring Requirements
62 - 65. General Recordkeeping Requirements
66 - 70 Boiler NESHAP Recordkeeping Requirements
71 - 75 General Reporting Requirements

3.7.5.4 Georgia Pacific - Wauna Mill (04-0004)

In a letter dated January 21, 2021, DEQ notified Georgia Pacific of its preliminary determination that their Wauna facility would likely be required to install control devices on several of its emissions units, as shown in Table 3-44Table 3-44, including Low NO_x Burners and SCR.

Table 3-44: Control devices likely required Georgia Pacific – Wauna Mill.

Emissions Unit	Control Device	Target Pollutant
Paper Machine 1: Yankee Burner	LNB	NO_x
Paper Machine 2: Yankee Burner	LNB	NO_x
Paper Machine 5: Yankee Burner	LNB	NO_x
21 - Lime Kiln	LNB	NO_x
Paper Machine 6: TAD1 Burners	LNB	NO_x
Paper Machine 7: TAD1 Burners	LNB	NO_x
Paper Machine 6: TAD2 Burners	LNB	NO_x
Paper Machine 7: TAD2 Burners	LNB	NO_x
33 - Power Boiler	SCR	NO_x

In a letter to DEQ dated April 30, 2021, Georgia Pacific stated concerns with installing SCR or SNCR on the power boilers based on undesirable associated effects such as health exposure and safety risk of handling and storing aqueous ammonia, ammonia slip, increased water usage and subsequent wastewater disposal, and higher electricity and natural gas use. Georgia Pacific also stated concerns with installing a low NO_x burner on the lime kiln based on such installation not being likely to alter all the pathways to NO_x formation and not necessarily resulting in a lower annual NO_x emission rate. Georgia Pacific also submitted information showing that emission reductions from low NO_x burner installation on Paper Machine 1 and 2 Yankee Burners would be less than the 20 tons per year threshold that DEQ had set.

Georgia Pacific proposed to install LNB on the remaining units and to install LNB and flue gas recirculation on the power boiler, with continuous monitoring, rather than SCR. With continuous emission monitoring on the power boiler, an emission limit of 0.09 lb/MMBtu on a 7-day rolling average, and a NO_x PSEL reduction of 726 tons/year, DEQ accepted GP's proposal. On August 9, 2021, Georgia Pacific entered a stipulated agreement and order with DEQ. The order is included in Appendix E. The order requires the following and contains other requirements and provisions:

- On August 1, 2022, PSELs are: PM10 = 1,077 tons/year; NO_x = 2,019 tons/year; SO_2 = 913 tons/year.
- On December 31, 2024, PSELs are PM10 = 1,077 tons, NO_x = 1,999 tons, and SO_2 = 913 tons.
- On July 31, 2026, PSELs are PM10 = 1,077 tons, NO_x = 1,413 tons, and SO_2 = 913 tons.
- For the Paper Machine 5 Yankee Burner, by December 31, 2024, permittee shall replace existing Yankee burner with a Low NO_x Burner achieving <= 0.03 Ib/MMBtu.
- For the TAD1 and TAD 2 burners on Paper Machines 6 and 7, permittee shall have a NO_x emissions rate no greater than 0.06 Ib/MMBtu and shall use this emission rate for PSEL compliance.
- For Power Boiler - 33, by December 31, 2022, permittee shall meet with DEQ to discuss the technical details of the low NOx burner, flue gas recirculation, and CEMS installation to determine what permitting permittee shall need prior to construction.
- As expeditiously as practicable, but not later than July 31, 2026, permittee shall install low NO_x burners and flue gas recirculation in order to achieve an emissions rate no greater than 0.09 Ib/MMBtu on a seven day rolling basis.
- Within one year of completing the Power Boiler project, but not later than July 31, 2026, permittee shall install a CEMS to measure the emissions of NO_x from Power Boiler - 33.
- Upon DEQ's approval of the CEMS certification, permittee shall use data collected from the CEMS to demonstrate compliance with the applicable NO_x PSEL.

3.7.5.5 Cascade Pacific Pulp, LLC - Halsey Pulp Mill (22-3501)

In a letter dated January 21, 2021, DEQ notified Cascade Pacific Pulp of its preliminary determination that their Halsey facility would likely be required to install LNB/Flue Gas Recirculation on their Power boiler #1, and also switch to Ultra Low Sulfur Diesel instead of #6 fuel oil as an emergency backup fuel on site. The facility had previously demonstrated that SNCR was not technically feasible due to the dimensions of the boiler.

On August 9, 2021, Cascade Pacific entered a stipulated agreement and order with DEQ to eliminate use of #6 fuel oil and conduct source testing and install a low NO_x burner on Power Boiler #1. In response to EPA comments submitted during the public comment period, DEQ and Cascade Pacific negotiated a second SAFO, included in Appendix E, that requires the following and contains other requirements and provisions:

- The permittee not combust fuel oil #6 at any emission unit in the facility by June 30, 2024.
- By January 31, 2022, conduct source testing for NO_x at Power Boiler #1.
- By March 31, 2024, finalize design of low NO_x burner to be installed on Power Boiler #1, designed to achieve 33% reduction in NO_x emissions.
- By March 31, 2025, construct and install the low NO_x burner at Power Boiler #1.

- Beginning on April 1, 2025, Permittee's emissions of NO_x from Power Boiler #1 shall be at least 20% less than the current emission factor of 282 lb NO_x per MM ft3 natural gas and shall be demonstrated to meet this emission reduction through source testing.
- By June 30, 2025, Permittee shall conduct source testing for NO_x at Power Boiler #1.
- By September 30, 2025, Permittee shall submit to DEQ a report that analyzes the data and information collected in source testing. The report shall include a proposal from Permittee on a revised emission limit in lb NO_x per MM ft3 natural gas for Power Boiler #1. DEQ will consider the Permittee's proposal and will make a determination of the final emission limit for incorporation into the Permit pursuant to 340-218-0200(1)(a)(A), if applicable, or upon permit renewal.
- By March 31, 2023, In lieu of installing a low NO_x Burner in Power Boiler #1 and associated requirements, Permittee may request in writing to replace Power Boiler #1 with new technology to reduce round II regional haze pollutants.
- If Permittee, makes a request to replace Power Boiler 31, then:
    - DEQ and Permittee shall meet no later than January 1, 2025, to discuss the project and determine what permitting is needed to approve the proposed replacement and a permit application schedule.
    - The technology proposed by Permittee for replacement shall meet the emission limits and requirements of the most recent New Source Performance Standard in place at the time of the Permittee submitting a permit application for the project.
    - NO_x emissions from the proposed replacement shall meet the emission limits and requirements of the most recent applicable standard in place at the time of the permitting of the new emissions unit.
    - Permittee shall meet all permitting deadlines and provide a complete permit application to DEQ, including any required permitting fees. Both parties will agree to a schedule for permitting of the construction project during this meeting.
    - Permittee shall submit an application for a construction for replacement project in accordance with, and by the deadline established in the SAFO
    - Upon completion of the replacement, Permittee shall not operate Power Boiler #1.
    - Permittee shall complete the replacement no later than July 31, 2031.

3.7.5.6 Boise Cascade Wood Products, LLC - Medford (15-0004)

In a letter dated January 21, 2021, DEQ notified Boise Cascade Wood Products of its preliminary determination that their Medford facility would likely be required to install SCR on Boilers 1, 2 and 3. Boise Cascade provided DEQ technical memo dated April 19, 2021 in which Boise Cascade's consultant concluded that SCR was not technically feasible on boilers at the Medford facility, citing in particular, concerns with irregular operating loads, fuel type (bark) that contains metals and other constituents that deactivate catalysts, and such catalyst poisoning constituents being prevalent in Oregon soils (and wood).

Rather than install controls, Boise Cascade chose the alternative compliance option to accept federally enforceable reductions of combined plant site emission limitation limits of Round 2 regional haze pollutants to bring the facility's Q/d below 5.00. On August 9, 2021, Boise Cascade entered a stipulated agreement and order with DEQ, included in Appendix E, that requires the following and contains other requirements and provisions:

- From August 1, 2021, to July 31, 2023, the Permittee's PSELs are: 396 tons for PM10 + $NO_x + SO_2$ (Q/d = 6.53).
- From August 1, 2023, to July 31, 2024, the Permittee's PSELs are: 381 tons for PM10 + $NO_x + SO_2$ (Q/d = 6.29).
- From August 1, 2024, to July 31, 2025 the Permittee's PSELs are: 365 tons for PM10 + $NO_x + SO_2$ (Q/d = 6.03).
- From August 1, 2025, to July 31, 2026 the Permittee's PSELs are: 347 tons for PM10 + $NO_x + SO_2$ (Q/d = 5.73).
- On August 1, 2026, the Permittee's PSELs for the following pollutants are: 302 tons for PM10 + $NO_x + SO_2$ (Q/d = 4.99).

DEQ will enforce compliance with the PSEL reductions through the facility’s Title V permit monitoring, recordkeeping and reporting requirements. DEQ submits the following sections of permit number 15-0004-TV-01 with this Regional Haze SIP for approval:

68 – 70. Plant Site Emission Limits: for PM10, NO_x, and SO_2
71: Plant Site Emission Limit Monitoring: for PM10, NO_x, and SO_2
72. Source-specific Recordkeeping Requirements
74. General Testing Requirements
75 – 77. General Monitoring and Recordkeeping Requirements
78 – 81. General Recordkeeping Requirements
82 – 86. General Reporting Requirements
87 – 88. Semi-annual and Annual Reports

3.7.5.7 Gas Transmission Northwest LLC - Compressor Station 12 (09-0084)

In a letter dated January 21, 2021, DEQ notified Gas Transmission Northwest of its preliminary determination that Compressor Station #12 would likely be required to install SCR on turbines 12A and 12B. On August 9, 2021, Gas Transmission Northwest entered a stipulated agreement and order with DEQ, included in Appendix E, that requires the following and contains other requirements and provisions:

- From August 1, 2022, the Permittee's PSELs are 12.7 tons per year for PM10; 317.1 tons per year for NOx; and 30.4 tons per year for SO_2.
- From August 1, 2023, the Permittee's PSELs are: 11.4 tons per year for PM10; 257.2 tons per year for NOx; and 21.7 tons per year for SO_2.
- From August 1, 2024, the Permittee's PSELs are: 10.2 tons per year for PM10; 197.3 tons per year for NOx; and 13.1 tons per year for SO_2.
- From August 1, 2025, the Permittee's PSELs are: 8.9 tons per year for PM10; 137.4 tons per year for NOx; and 4.4 tons per year for SO_2.

DEQ will enforce compliance with the PSEL reductions through the facility’s Title V permit monitoring, recordkeeping and reporting requirements. DEQ submits the following sections of permit number 09-0084-TV-01 with this Regional Haze SIP for approval:

32 - 34: General Monitoring Requirements
37 - 38: Emission Unit Specific Monitoring

39: Plant Site Emissions Monitoring, Table 8 (PSEL Procedures, Test Methods, and Frequencies), Emission Calculation, Table 9 (Pollutant Emission Factors)
40 - 43: General Recordkeeping Requirements
44: Source Specific Recordkeeping Requirements
45 - 48: General Reporting Requirements
49 - 50: Semi-annual and annual reports

3.7.5.8 Gas Transmission Northwest LLC - Compressor Station 13 (18-0096)

In a letter dated January 21, 2021, DEQ notified Gas Transmission Northwest of its preliminary determination that Compressor Station #13 would likely be required to install SCR on turbines 13C and 13D. On August 9, 2021, DEQ issued a unilateral order, included in Appendix E, that requires the following and contains other requirements and provisions:

- By July 31, 2023, submit a complete and approvable permit application for the installation and operation of SCR and CEMS on Turbines 13C and 13D;
- By July 31, 2024, install a CEMS on Turbines 13C and 13D;
- By July 31, 2026, install, maintain and continuously operate SCR on Turbines 13C and 13D with a minimum control efficiency of 90%.

3.7.5.9 International Paper Company – Springfield Mill (TV #208850)

In a letter dated January 21, 2021, DEQ notified International Paper of its preliminary determination that their Springfield facility would likely be required to install SCR on the Power Boiler (EU-150A) and also take several actions related to restricting alternative or emergency fuels, as shown in Table 3-45.

Table 3-45: Control devices DEQ found cost-effective at International Paper Company – Springfield Mill.

Emissions Unit	Control Device	Target Pollutant
Power Boiler EU-150A	SCR	NO_x
Facility-wide	Eliminate use of #6 fuel oil and petroleum coke fuel. Replace backup fuels with ULSD	multiple
Power Boiler (EU-150A), Package Boiler (EU-150B)	Restrict annual use of ULSD to NESHAP 5D "Gas 1" unit allowance	multiple
No. 4 Recovery Furnace (EU-445C), Lime Kilns #2 & 3 (EU-455)	Restrict use of ULSD to only periods of natural gas curtailment	multiple

For the power boiler, DEQ deemed equivalent emission reduction could be achieved through PSEL reduction across all emission units and continuous emission monitoring on the power boiler to monitor compliance with an emission rate of 0.25 lb NOx/MMBtu on a 7-day rolling average. On August 9, 2021, International Paper entered a stipulated agreement and order with DEQ and LRAPA, included in Appendix E. The order requires the following and contains other requirements and provisions:

- On and after July 31, 2022, the Permittee' s combined assigned PSELs for the Power Boiler, Package Boiler, Lime Kilns and Recovery Furnace for the following pollutants are:

237 tons per year for SO_2, as a 12-month rolling average; 962 tons per year for NOx, as a 12-month rolling average; 177 tons per year for PMl0, as a 12-month rolling average.

- the only fuel that it may combust in the Power Boiler and Package Boiler is natural gas, except that it may operate the Power Boiler and Package Boiler on ultra-low sulfur diesel for no more than 48 hours per year and when needed for natural gas curtailments.

- the only fuels that it may combust in the Recovery Furnace are Black Liquor Solids and natural gas, except that it may operate the Recovery Furnace on ultra-low sulfur diesel no more than 48 hours per year and when needed for natural gas curtailment.

- the only fuels that it may combust in the Lime Kilns are natural gas, product turpentine and product methanol, except that it may operate the Lime Kilns on ultra-low sulfur diesel no more than 48 hours per year and when needed for natural gas curtailment.

- By December 31, 2022, International Paper shall install CEMS and measure the emissions of NO_x from the Power Boiler.

- Upon demonstrating proper installation of the NO_x CEM by completing performance/certification testing no later than March 31, 2023, International Paper shall ensure that the CEMS are certified/approved by DEQ and LRAPA no later than May 31, 2023.

- International Paper shall use the CEMS to document Power Boiler NO_x emissions, replacing the Power Boiler NO_x PSEL monitoring condition 186.g, no later than May 31, 2023.

- On and after January 31, 2025, International Paper shall meet the following emission limit: a 0.25 lb NOx/MMBtu on a 7-day rolling average from the Power Boiler.

- On and after December 31, 2025, the Permittee's assigned PSEL for the following pollutants and Emission Unit is: 179 tons per year for NOx, as a 12-month rolling average for the Power Boiler.

DEQ and LRAPA will enforce compliance with the PSEL reductions through the facility's Title V permit monitoring, recordkeeping and reporting requirements. DEQ submits the following sections of permit number 208850 with this Regional Haze SIP for approval:

Conditions 186 – 189: PSEL monitoring for PM10, NO_x and SO_2
Condition 192: recordkeeping requirements
Condition 198: PSEL compliance reporting.

3.7.5.10 Georgia-Pacific – Toledo LLC (21-0005)

In a letter dated January 21, 2021, DEQ notified Georgia Pacific of its preliminary determination that their Toledo facility would likely be required to install control devices on several of its emissions units, as shown in Table 3-46. DEQ agreed at the time that cost effectiveness of adding a baghouse to EU-118 could be revised after the results of upcoming source testing.

Table 3-46: Control devices DEQ found cost-effective at Georgia-Pacific, Toledo

Emissions Unit	Control Device	Target Pollutant
EU-118 Hardwood Chip handling	Baghouse	PM10
EU-1 Lime Kiln	LNB	NO_x
EU-2 Lime Kilns	LNB	NO_x
EU-3 Lime Kiln	LNB	NO_x
EU-11 No. 4 Boiler	SCR	NO_x
EU-13 No. 1 Boiler	SCR	NO_x
EU-18 No. 3 Boiler	SNCR	NO_x

Georgia Pacific performed a source test on the EU-118 Emission Unit and demonstrated that the emissions from this unit were substantially lower than previously estimated. DEQ agreed that a baghouse on EU-118 would no longer be cost-effective. GP also submitted information, which DEQ accepted, that showed low NO_x burners to be technically infeasible on the lime kilns because of the high temperatures required. As an alternative to SCR and SNCR on the boilers, GP proposed LNB and flue gas recirculation. With continuous emission monitoring and an emission limit of 0.09 lb/MMBtu on a 7-day rolling average, a NO_x PSEL reduction of 398 tons/year and an agreement to replace the boilers if the emission rate was not achievable, DEQ accepted GP's proposal.

On August 9, 2021, Georgia Pacific Toledo entered a stipulated agreement and order, contained in Appendix E, that required the following and contains other requirements and provisions:

- Either complete a NO_x reduction project that includes the installation of low NO_x burners, flue gas recirculation and CEMS on the three Boilers, EU-11, EU-13, and EU-18 or replace the boilers with one or more new boilers.
- Determine whether to complete the NO_x reduction project or replace the boilers by July 31, 2022, and meet with DEQ by December 31, 2022, to discuss the technical details of the selected project to determine needed permitting.
- If Permittee chooses to complete a NO_x reduction project:

  By July 31, 2026, Permittee shall install low NO_x burners and flue gas recirculation on EU-11, EU-13, and EU-18 in order to achieve an emissions rate no greater than 0.09 lb/MMBtu on a seven day rolling basis.

  As expeditiously as practicable, but not later than July 31, 2026, install a CEMS to measure the emissions of NO_x from EU-11, EU-13, and EU-18.

- If Permittee chooses to replace EU-11, EU-13, and EU-18:

  PSELs for Round 2 regional haze pollutants incorporated in the Permit for the replacement shall be no more than the potential to emit of the replacement, or a Q of 889 tons per year of NOX, 437 tons per year of SO_2, and 311 tons per year of PM10, whichever is lower.

  Complete the replacement of the EU-11, EU-13, and EU-18 with new technology no later than July 31, 2031.

3.7.5.11 Northwest Pipeline LLC - Baker Compressor Station (01-0038)

In a letter dated January 21, 2021, DEQ notified Northwest Pipeline of its preliminary determination that its Baker Compressor Station would likely be required to install Low Emissions Combustion controls on engines EU1 (compressor units C1, C2 and C3 combined) and EU2.

On August 9, 2021, Northwest Pipeline entered a stipulated agreement and order for PSEL reduction or alternately, emission unit replacement. After receiving comment from EPA during the public comment period, DEQ and Northwest Pipeline executed an amended SAFO, included in Appendix E, that included a date by which a new emission unit would need to be installed if Northwest Pipeline chose that option. The SAFO specifies that Northwest Pipeline must lower PSELs on the following schedule:

- From August 1, 2022, to July 31, 2023, the Permittee's PSELs for the following pollutants are: 5 tons for PM10; 473 tons for NOx; and 2 tons for SO_2.
- From August 1, 2023, to July 31, 2024, the Permittee's PSELs for the following pollutants are: 5 tons for PM10; 404 tons for NOx; and 2 tons for SO_2.
- From August 1, 2024, to July 31, 2025, the Permittee's PSELs for the following pollutants are: 5 tons for PM10; 335 tons for NOx; and2 tons for SO_2.
- From August 1, 2025, to July 31, 2026, the Permittee's PSELs for the following pollutants are: 5 tons for PM10; 266 tons for NOx; and 2 tons for SO_2.
- On August 1, 2026, the Permittee's PSELs for the following pollutants are: 5 tons for PM10; 193 tons for NOx; and 2 tons for SO_2.

Alternatively, the facility, up until July 2026, could opt to commit to replace units EU1 and EU2 with new technology by July 31, 2031, that would reduce Round 2 regional haze pollutants. The technology would have to meet the emission limits and requirements of the most recent New Source Performance Standard in place at the time of the permittee submitting a permit application for the project. PSELs for Round 2 regional haze pollutants for the replacement shall be no more than 201 tons/year.

DEQ will enforce compliance with the PSEL reductions through the facility’s Title V permit monitoring, recordkeeping and reporting requirements. DEQ submits the following sections of permit number 01-0038-TV-01 with this Regional Haze SIP for approval:

27 - 30: General Monitoring Requirements
32: Plant Site Emissions Monitoring, Table 6 (Process monitoring), Emission Calculation, Table 7 (Emission Factors) for EU1 and EU2
33 - 36: General recordkeeping requirements
37: Source specific recordkeeping requirements for EU1 and EU2
38 - 41: General reporting requirements
42 - 43: Semi-annual and Annual Reports

3.7.5.12 Northwest Pipeline LLC - Oregon City Compressor Station (03-2729)

In a letter dated January 21, 2021, DEQ notified Northwest Pipeline of its preliminary determination that its Oregon City Compressor Station would likely be required to install low-emission combustion controls on EU1 (Ingersoll-Rand 412KVS Engines 1 and 2).

On August 9, 2021, Northwest Pipeline entered a stipulated agreement and order with DEQ. After receiving comment from EPA during the public comment period, DEQ and Northwest Pipeline executed an amended SAFO, included in Appendix E, that included a date by which a new emission units would need to be installed. Northwest Pipeline agreed to replace two RICE that comprise EU1 at the facility with new emissions units to reduce PSELs of round II regional haze pollutants. The technology would have to meet the emission limits and requirements of the most recent New Source Performance Standard in place at the time of the permittee submitting a permit application for the project. PSELs for Round 2 regional haze pollutants for the replacement shall be no more than the potential to emit of the replacement or 219 tons/year, whichever is lower.

3.7.5.13 EVRAZ Inc. NA (26-1865)

In a letter dated January 21, 2021, DEQ notified EVRAZ of its preliminary determination that their facility would likely be required to install LNB on their reheat furnace. On August 9, 2021, EVERAZ entered a stipulated agreement and order with DEQ, included in Appendix E, and agreed to install low NOx burners on the pre-heat portions of the EU-10 Reheat Furnace with a designed NOx emission factor of 170 pounds per million cubic feet of natural gas, by December 31, 2024. The order also requires source testing to verify the emission factor, associated reporting to DEQ, and permit modification.

3.7.5.14 Biomass One, L.P. (15-0159)

In a letter dated January 21, 2021, DEQ notified Biomass One of its preliminary determination that their facility would likely be required to install SCR on their North Boiler and South Boiler. On August 9, 2021, Biomass One entered a stipulated agreement and order, included in Appendix E, that requires the following and contains other requirements and provisions:

- Install a Continuous Emission Monitoring System, submit to DEQ a NO_x optimization plan that describes the permittee's plan to use the CEMS data to operate in a way that minimizes NO_x emissions and implement the plan.
- If a new power purchase agreement is signed, within 180 days of notifying DEQ, Biomass One shall submit a complete application for installation of NO_x reduction technology that includes SCR on the North and South Boiler or demonstrates SCR is technically infeasible or presents other unacceptable energy or non-air quality impacts.
- If SCR is technically infeasible or presents such other unacceptable impacts, the Permittee will propose the best available, technically feasible and achievable NO_x reduction option for DEQ's review and approval.
- Permittee shall install controls approved by DEQ within 18 months of that approval.

3.7.5.15 Roseburg Forest Products - Dillard (10-0025)

DEQ’s preliminary determination was that installation of SNCR would be cost-effective on Boiler 1, Boiler 2 and Boiler 3 at this facility. DEQ did not include this facility in the January 21, 2021, letters because DEQ was already in discussions with the facility about how to achieve similar emission reduction by optimizing the operation of the boiler.

On August 9, 2021, Roseburg Forest Products entered a stipulated agreement and order, contained in Appendix E, that required the following and contains other requirements and provisions:

By July 31, 2022, Permittee shall install CEMS to measure the emissions of NO_x from Boiler 1, Boiler 2 and Boiler 6. 2. From January 31, 2023 until June 30, 2025, Permittee shall meet the following emission limits:

- 0.30 lb NOx/MMBtu on a 7-day rolling average at Boiler 1;
- 0.30 lb NOx/MMBtu on a 7-day rolling average at Boiler 2;
- 0.28 lb NOx/MMBtu on a 7-day rolling average at Boiler 6; Or
- average of emissions from boiler 1, boiler 2, and boiler 6 of 0.28 lb NOx/MMBtu (7-day rolling average)

By January 31, 2024, the permittee shall notify DEQ whether the permittee with comply with emission limits using boiler optimization or through installation of SNCR. If permittee determines SNCR is necessary to meet emission limits, SNCR shall be installed, permitted, and operational by June 30, 2025.

3.7.5.16 JELD-WEN (18-0006)

In a letter dated January 21, 2021, DEQ notified JELD-WEN of its preliminary determination that their facility would likely be required to install SNCR on their Wood Fired Boiler (BLRG). Rather than install controls, Jeld-Wen decided to reduce their PSEL so that Q/d < 5. DEQ is drafting the permit modification to reflect this PSEL reduction but the permit modification was not complete at the time of this Regional Haze SIP submission.

DEQ will enforce compliance with the PSEL reductions through the facility's Title V permit monitoring, recordkeeping and reporting requirements. DEQ submits the following sections of permit number 18-0006-TV-01 with this Regional Haze SIP for approval:

53. Plant Site Emission Limits: for PM10, NOx, and SO_2
55 – 57. Testing Requirements
58 – 60. General Monitoring Requirements
61 – 64. Facility-wide Monitoring Requirements
65 – 71. Emissions Unit Specific Monitoring
72. Plant Site Emissions Monitoring: for PM10, NOx, SO_2
73 – 76. General Recordkeeping Requirements
77. Source Specific Recordkeeping Requirements
80 – 84. General Reporting Requirements
85 – 87. Semi-annual and Annual Reports

3.7.5.17 Willamette Falls Paper Company (03-2145)

In a letter dated January 21, 2021, DEQ notified Willamette Falls Paper of its preliminary determination that their facility would likely be required to install control devices on several of its emissions units, and accept restrictions on emergency backup fuel. On August 9, 2021, Willamette Falls Paper Company entered a stipulated agreement and order, included in Appendix E, to lower PSELs as follows and contains other requirements and provisions: on August 1, 2022, the permittee's PSELs for the following pollutants are: 20 tons/year for PM10, 240 tons/year for NO_x and 5 tons/year for SO_2. The order also states that the only fuel the permittee may combust in Boiler 1, Boiler 2 and Boiler 3 is natural gas, except for ULSD for no more than 48 hours/year.

DEQ will enforce compliance with the PSEL reductions through the facility's Title V permit monitoring, recordkeeping and reporting requirements. DEQ submits the following sections of permit number 03-2145-TV-01 with this Regional Haze SIP for approval:

38. Plant Site Emission Limits: for PM10, NOx, SO_2
40a – 40g. Monitoring Requirement: for PM10, NOx, SO_2
41. Visible Emission Monitoring Procedure
42. Source Testing and Emission Factor Verification Procedure: for PM10, NOx, SO_2
43 – 45. General Monitoring Requirements
46 – 49. General Recordkeeping Requirements
50 – 53. General Reporting Requirements
54 – 56. Semi-annual and Annual Reports

3.8 Federal Enforceability

This 2017 Regional Haze Rule (Section 51.308(f)(2)) requires that a state's long-term strategy include "the enforceable emission limitations, compliance schedules and other measures that are necessary to make reasonable progress."

3.8.1 Rulemaking

In July 2021, DEQ completed rulemaking to codify the screening procedure to identify facilities required to undergo four factor analysis, the process to determine cost effectiveness of controls and means of compliance. The Oregon Environmental Quality Commission adopted Division 223 Regional Haze rules at its July 22 – 23, 2021 meeting.

3.8.2 Department Orders

With Division 223 rule adoption, EQC gave DEQ the authority to issue orders to each facility required to install controls or otherwise reduce emissions of Round 2 regional haze pollutants. The orders specify emission limits, averaging periods, and schedules for control installation or PSEL reduction, as appropriate for the means of compliance on which DEQ and each facility settled. DEQ has incorporated in this Regional Haze SIP the Title V permit conditions providing monitoring, recordkeeping and reporting requirements for sources taking PSEL reductions as a means of compliance. Each order became effective on the issuance date. The orders for each facility required to install controls or reduce emissions – described in Section 3.7 – are included in Appendix E.

3.8.3 Permit Modification

DEQ, working with sources, will implement the order requirements through permit modifications. DEQ will require facilities that must install controls to submit an ACDP application and notice of construction. DEQ will then open associated Title V permits for cause and modify the permit for the new controls and revised emission limits. For facilities ordered to reduce PSELs, DEQ will incorporate the PSEL reductions at the source's next permit renewal.

4 Long-term strategy

The 2017 Regional Haze Rule (51.308(f)) requires DEQ to submit a long-term strategy that addresses regional haze visibility impairment for each Class 1 area within the State and for each Class 1 area located outside Oregon that may be affected by Oregon emissions. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures necessary to achieve the reasonable progress goals.

4.1 Information consulted and technical basis for Long-term Strategy

DEQ took several factors into account in compiling the elements of Oregon's Long-term Strategy to meet Regional Haze reasonable progress goals. DEQ relied on the regional modeling results available through WRAP and the TSS, as well as monitoring data from the IMPROVE sites to analyze pollutant contributions and source apportionment. DEQ consulted the 2017 National Emissions Inventory to understand total and relative pollutants contributions among sectors and variation among different parts of the state. This report discusses IMPROVE measurements in Section 2.4, WRAP's modeled source apportionment from the IMPROVE monitoring sites in Section 2.5 and the 2017 emissions inventory in Section 2.3. This monitored and analyzed data, modeling and reported emissions informed Oregon's apportioned emission reduction obligations. DEQ also relied on agency staff expertise – primarily operations and permit engineers and analysts – as well as permit files to inform the stationary source long-term strategy elements.

As described in the introduction to Chapter 3 and Section 3.6 of this Regional Haze Plan, DEQ also qualitatively considered non-air and environmental factors in developing its Long-term Strategy for the 2018 – 2028 implementation period. DEQ considered the public health co-benefits to vulnerable populations in the vicinity of regulated stationary sources. DEQ also considered ecological co-benefits of reducing nitrogen and sulfur deposition in sensitive land and water ecosystems.

4.2 Anthropogenic Sources Considered in Developing Long-term Strategy

To support a state's long-term strategy, the 2017 Regional Haze Rule (§51.308(f)(2)) requires a state to identify all anthropogenic sources of visibility impairment that the state considered – including major and minor stationary sources, mobile sources, and area sources. The state must also document the technical basis, including modeling, monitoring and emissions information, which informed the state's apportioned emission reduction obligations.

After considering the four factors in determining the measures necessary to make reasonable progress [CFR 51.308(f)(2)(i)], DEQ considered the five additional factors at 40 CFR 51.308(f)(2)(iv) in developing its long-term strategy, including:

- (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
- (B) Measures to mitigate the impacts of construction activities;

- (C) Source retirement and replacement schedules;
- (D) Smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
- (E) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

4.3 Findings informing Long-term Strategy

At the eastern Oregon IMPROVE sites (Hells Canyon and Strawberry Mountain/Eagle Cap) ammonium nitrate causes the most visibility impairment; while the absolute and relative contribution of ammonium nitrate has decreased from the baseline period, WRAP modeling shows the contribution has increased slightly since the last regional haze reporting period. For the IMPROVE sites in the Cascades and Kalmiopsis, absolute contribution from ammonium sulfate has continued to decline from the baseline period, although relative ammonium sulfate contribution remains high.

DEQ, as described in Section 2.5, consulted WRAP's source apportionment and weighted emission potential analysis to estimate relative visibility impairment from mobile onroad, nonroad, area and stationary sources – divided into EGU and non-EGU sources. Using WRAP's modeling, coupled with IMPROVE monitoring results, DEQ discerned contributions from the following categories: US anthropogenic, international anthropogenic, natural, US wildfire, US prescribed wildland fire, and Mexico/Canada wildfire. DEQ discerned that visibility at Oregon IMPROVE sites is most affected by ammonium sulfate from international and natural sources, and organic carbon from US wildfires, US prescribed fires, and natural sources. Within US anthropogenic sources, the three largest contributors to visibility impairment are ammonium nitrate, ammonium sulfate and organic carbon.

The Mount Hood IMPROVE site shows extinction from US anthropogenic sources is mainly from ammonium nitrate and organic carbon, which DEQ expects comes from combustion and transportation sources, as well as VOC use, in the Portland metropolitan area and Columbia River Gorge.

The emission inventory DEQ compiled for this Regional Haze plan provides more specificity around annualized haze-contributing emissions originating in Oregon, both statewide and at the county level. Statewide, major source sectors contributing to particulate matter are prescribed fire and agriculture. NO_x emissions are primarily from mobile sources and other fuel combustion. With PGE Boardman's SO_2 emissions eliminated by the coal-fired power plant's closure in October 2020, the remainder of SO_2 emissions come from fuel combustion and prescribed fires.

DEQ did not designate VOCs as Round 2 Regional Haze pollutants, however, DEQ recognizes that anthropogenic VOCs are likely components of organic carbon species that contribute to visibility impairment. DEQ controls mobile source VOCs through programs described in section 4.4. Within this Regional Haze implementation period DEQ intends to develop rules to reduce VOCs at gasoline dispensing facilities by updating requirements for Stage II vapor recovery controls. DEQ also intends to develop statewide rules to reduce VOCs in consumer products and work with Washington and Idaho to formulate a northwest regional strategy.

In Table 4.1, DEQ summarizes pollutants and source categories that monitoring and modeling suggest contribute most to regional haze at each IMPROVE site location. DEQ bases the top pollutants on the 2014 – 2018 speciation and light extinction calculations for each IMPROVE site, compiled from the WRAP TSS and illustrated in Figures 2-3 through 2-8. DEQ summarizes contributing categories in Table 4-1 from the weighted emission potential and source apportionment modeling discussed in Section 2.5. DEQ intends to apply each of the long-term strategies statewide, however, in Table 4-1 DEQ calls out those strategies most applicable to the top pollutants and likely sources at each IMPROVE site.

Table 4-1 Top contributing pollutants, sources, and long-term strategies, summary by IMPROVE site.

IMPROVE Location	Top 3 Monitored Pollutants[a]		Greatest Contributing Sources[b]	Applicable Strategies
HECA	Ammonium nitrate Organic mass Ammonium sulfate	*NOx*	Onroad mobile Nonroad mobile Non-EGU point sources	• Mobile source emission controls • Stationary source emission controls
		SOx	Non EGU point source Area sources Onroad mobile sources	• Stationary source emission controls • Smoke mgmt./open, agriculture/residential wood burning programs • Mobile source emission controls
		PM	Area sources Non EGU point sources Nonroad mobile sources	• Smoke mgmt./open, agriculture/residential wood burning programs • Stationary source emission controls • Mobile source emission controls
STAR	Ammonium nitrate Organic mass Ammonium sulfate	*NOx*	Onroad mobile sources Nonroad mobile sources Non EGU point sources	• Mobile source emission controls • Stationary source emission controls
		SOx	Non EGU point sources Area sources EGU point sources	• Stationary source emission controls • Smoke mgmt./open, agriculture/residential wood burning programs
		PM	Area sources Non EGU point sources Nonroad mobile sources	• Smoke mgmt./open, agriculture/residential wood burning programs • Stationary source emission controls • Mobile source emission controls
MOHO	Ammonium sulfate Organic mass Ammonium nitrate	*NOx*	Nonroad mobile sources Onroad mobile sources Non EGU point sources	• Mobile source emission controls • Stationary source emission controls
		SOx	Area sources Non EGU point sources Onroad/nonroad mobile sources	• Smoke mgmt./open, agriculture/residential wood burning programs • Stationary source emission controls • Mobile source emission controls
		PM	Area sources Nonroad mobile sources Non EGU point sources	• Smoke mgmt./open, agriculture/residential wood burning programs • Mobile source emission controls • Stationary source emission controls
THSI	Ammonium sulfate Organic mass Elemental carbon	*NOx*	Onroad mobile sources Nonroad mobile sources Non EGU point sources	• Mobile source emission controls • Stationary source emission controls
		SOx	Non EGU point sources Area sources Onroad/nonroad mobile sources	• Stationary source emission controls • Smoke mgmt./open, agriculture/residential wood burning programs • Mobile source emission controls
		PM	Area sources Non EGU point sources Onroad/nonroad mobile sources	• Smoke mgmt./open, agriculture/residential wood burning programs • Stationary source emission controls • Mobile source emission controls

CRLA	Ammonium sulfate Organic mass Elemental carbon	*NOx*	Onroad mobile sources Nonroad mobile sources Non EGU point sources	• Mobile source emission controls • Stationary source emission controls
		SOx	Non EGU point sources Area sources Onroad/nonroad mobile sources	• Stationary source emission controls • Smoke mgmt./open, agriculture/residential wood burning programs • Mobile source emission controls
		PM	Area sources Non EGU point sources Onroad/nonroad mobile sources	• Smoke mgmt./open, agriculture/residential wood burning programs • Stationary source emission controls • Mobile source emission controls
KALM	Ammonium sulfate Organic mass Elemental carbon	*NOx*	Onroad mobile sources Nonroad mobile sources Non EGU point sources	• Mobile source emission controls • Stationary source emission controls
		SOx	Non EGU point sources Area sources EGU point sources	• Stationary source emission controls • Smoke mgmt./open, agriculture/residential wood burning programs
		PM	Area sources Non EGU point sources EGU point sources	• Smoke mgmt./open, agriculture/residential wood burning programs • Stationary source emission controls

a: Based on measured extinction from IMPROVE monitoring data, WRAP Technical Support System website for the period 2014 to 2018. Illustrated in Figures 2-3 through 2-8.

b: Based on Weighted Emission Potential and source apportionment modeling, discussed in Section 2.5.

4.4 Necessary Emission Reduction Measures, On-going Air Pollution Control Programs and Source Retirement/Replacement

EPA's 2019 Regional Haze Guidance states, "If a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its LTS in the SIP." In addition, the guidance states, "The LTS can be said to include those controls only if the SIP includes emission limits or other measures (with associated averaging periods and other compliance program elements) that effectively require the use of the controls."

DEQ's long-term strategy for stationary sources that DEQ determined in Regional Haze Round 2 are likely to contribute to visibility impairment is to implement the mandatory controls and PSEL reductions described in Section 3.7. DEQ has issued a Department Order for each facility that mandates emission limits via control installation or PSEL reduction and compliance schedules. Monitoring, record keeping and reporting requirements are contained in the Orders or applicable Title V permit conditions that are incorporated into this Regional Haze SIP.

In addition to mandating new emission controls and reductions, DEQ will continue to implement rules on the books to protect visibility in Class 1 areas: Prevention of Significant Deterioration and New Source Review.

In developing this Regional Haze Plan's Long-term Strategy, DEQ considered source retirement and replacement during stationary source screening and four factor analysis, as described in sections 3.1, 3.4 and 3.7. For example, DEQ's analyses accounted for the permanent closure of the Boardman coal-fired power plant in October 2020.

4.5 Measures to Mitigate Impacts of Construction Activities and Mobile Source Strategies

This 10-year Regional Haze plan incorporates and recognizes significant local and state efforts to reduce mobile source emissions, including mitigating impacts of construction activities. Key efforts include:

- As a section 177 state, DEQ adopted recent California rules for medium- and heavy-duty on-road vehicles. In November 2021, Oregon's Environmental Quality Commission adopted new zero emission vehicle and NO_x standards for medium- and heavy-duty trucks.
- Local governments in the Portland-metro region, including the Port of Portland, Multnomah County and the City of Portland have adopted new procurement standards for construction projects which should result in significant reductions in the nonroad mobile source category.
- The Volkswagen and DERA grant programs aim to reduce emissions from diesel engines and provide funding to support the purchase of new, cleaner equipment across multiple sectors of the mobile source category.
- In 2019, the Oregon Legislature adopted HB 2007, prohibiting titling and registration of older (pre-2007 and pre-2010 model year) medium- and heavy-duty diesel trucks in Clackamas, Multnomah and Washington counties. By 2029 the laws will be in full effect.

Other Oregon-specific programs such as the Clean Fuels Program encourage fuel switching to fuels with lower carbon intensities. The Oregon Clean Vehicle Rebate Program incentivizes electric vehicle ownership in the state. DEQ's Vehicle Inspections Program plays an important part in reducing emissions from mobile sources in Medford and the Portland metropolitan areas. DEQ plans to expand the Employee Commute Options program to help reduce mobile sector pollution in the state's urban areas.

4.5.1 Programs to Reduce Medium and Heavy Duty Diesel Engine Emissions

Mandatory standards will go into effect in the Portland Metro region beginning in 2023 for in-use diesel, medium- and heavy-duty trucks. These standards will phase out certain older model medium and heavy duty diesel engines. Additional phase outs of older vehicles will occur in 2025 and 2029. By 2029 most medium and heavy-duty vehicles must be 2010 or newer unless retrofitted to reduce emissions. DEQ's Vehicle Inspection Program will be responsible for certifying compliance with the retrofit pathway and will be completing the rulemaking for this new policy in 2021.

DEQ adopted heavy and medium duty diesel engine standards by reference under Section 177 of the Clean Air Act from previously adopted California Air Resources Board standards that go into effect beginning in 2022. DEQ expects these standards to reduce greenhouse gasses and tailpipe emissions from new diesel vehicles by requiring a percentage of zero emission medium- and heavy-duty engines. The standards also reduce NO_x emissions from new medium and heavy-duty diesel engines by 90%. The standards apply to new vehicles and engines sold in Oregon, beginning with 2024 model year vehicles. DEQ expects some manufacturers to choose early compliance in order to place ZEV medium- and heavy-duty vehicles in the state for early credit through the Clean Fuels Program.

In 2021, DEQ developed model clean contracting standards for state contracting agencies to use as they set policies for equipment used on public projects in the Portland metropolitan area. Developing model clean contracting standards was an element of state legislation (HB 2007) which required that procurement standards go into effect in 2022. While the standards are not mandates or regulations, retrofitted or newer equipment will be required to complete work under these contracts as described in individual agency contracts and procurement policies. In general, the model standards focus on nonroad diesel engines but the standards have onroad components, as well.

With approximately $73 million in funding from the Volkswagen Mitigation Trust Fund court settlement and annual allocations from EPA under the Diesel Emission Reduction Act, Oregon is retrofitting, repowering, and replacing older diesel engines with newer, cleaner burning technology. This work requires older, more-polluting diesel equipment to be permanently destroyed, ensuring diesel emissions are reduced while supporting the purchase of new equipment that meets more stringent emissions standards. DEQ's initial target is to treat at least 450 school buses across the state. In early 2021, DEQ completed a rulemaking that set parameters for awarding remaining VW Mitigation Trust funding over the next 4 to 5 years. The grant program has an expanded focus, addressing additional kinds of diesel equipment as well as weighting the environmental justice benefits of diesel emission reduction projects.

4.5.2 Programs to Reduce Passenger Vehicle Emissions

DEQ's Vehicle Inspection Program requires light duty gasoline and diesel vehicles and heavy duty gasoline vehicles registered in the Portland and Medford metropolitan areas meet certain emissions standards before vehicle owners can renew vehicle registrations. VIP is a mandatory control set in the Portland area's Ozone Maintenance Plan and the Medford area's CO Maintenance Plan.

Oregon is a Section 177 state, a designation through which states can adopt vehicle standards that are more stringent than federal standards for new vehicles but must adopt California's rules identically. Oregon has opted in to California's vehicle emission standards and adopted Low Emission Vehicle and ZEV standards. The LEV program requires strict emission standards for the reduction of criteria pollutants and greenhouse gases and the ZEV program requires manufacturers to deliver a certain percentage of zero emission vehicles to Oregon. Additionally, DEQ is considering the adoption of several recent California rules for medium- and heavy-duty on-road vehicles. The department intends to propose new ZEV and NO_x standards for medium- and heavy-duty trucks in late 2021 for EQC consideration

Part of Oregon's transportation electrification strategy is the Oregon Clean Vehicle Rebate Program. The Oregon Clean Vehicle Rebate Program offers a cash rebate for Oregon drivers who purchase or lease electric vehicles. DEQ designed the program to reduce vehicle emissions by encouraging more Oregonians to purchase or lease electric vehicles rather than gas vehicles. The program contains two rebate options: a Standard Rebate for the purchase or lease of a new plug-in hybrid electric vehicle or a new battery electric vehicle and the Charge Ahead Rebate for income-qualified households who purchase or lease a new or used battery electric vehicle or plug-in hybrid electric vehicle.

In the Portland metropolitan area, DEQ implements the mandatory Employee Commute Options Program. These program rules are adopted as part of the Portland area Ozone Maintenance Plan and require employers with at least 100 employees at a worksite to offer commute alternatives to their employees. Employers must submit trip reduction plans for DEQ's approval, survey employees biannually and report results to DEQ. DEQ has initiated a rulemaking to expand the commute options program requirements to employers in other urban areas in Oregon. DEQ expects to complete this rulemaking in 2022.

4.5.3 Clean Fuels Program

The purpose of the Oregon Clean Fuels program is to reduce the carbon footprint associated with transportation. In 2009, the Oregon Legislature authorized the Oregon Environmental Quality Commission to adopt rules to reduce lifecycle emissions of greenhouse gases. In 2015, the Oregon Legislature removed a Dec. 31, 2015 sunset date, and the Oregon Clean Fuels Program began in 2016. The rules require a 10 percent reduction in transportation fuel average carbon intensity from 2015 levels by 2025.

CFP is a mandatory program that regulates transportation fuel importers. Regulated parties must register with DEQ before producing fuel in Oregon, importing fuel into Oregon or generating or transacting credits for fuels supplied in Oregon; keep records for each transaction of transportation fuel imported, sold or supplied for use in Oregon; and submit quarterly annual reports. The CFP sets a standard for gasoline and gasoline substitutes and one for diesel and diesel substitutes.

DEQ will be expanding the Clean Fuels Program over the next five years, including efforts to increase mandatory carbon intensity reductions. In 2021, DEQ will complete a rulemaking that will advance transportation electrification by helping utilities generate clean fuels credits. DEQ will also consider rule revisions that reduce the carbon intensity of electricity used as a transportation fuel, increase access to renewable electricity for transportation, and encourage new types of electric vehicles.

The program has created an Oregon market for lower-carbon fuels (e.g. ethanol, biodiesel, renewable diesel, electricity, hydrogen, and fossil and renewable natural gas and propane). Many of those fuels have lower or no PM, carbon monoxide, and NO_x tailpipe emissions. DEQ is currently working with researchers at the University of California, Davis, to begin to quantify tailpipe emission reductions. DEQ expects that implementation and expansion of CFP will continue to reduce haze forming pollutants from mobile sources.

4.6 Smoke Management Practices and Programs and Area Source Strategies

Area source sectors include prescribed fire, open burning, residential wood combustion, agriculture and dairies, rail, airports and facilities and products that emit volatile organic compounds.

4.6.1 Smoke Management and Prescribed Burning for Wildland Vegetation Management

Forestry prescribed burning occurs across the state and is controlled under a mandatory smoke management program operated by the Oregon Department of Forestry. Under state statute ORS 477.013, the State Forester and DEQ are required to protect air quality through a smoke management plan, which is included in the SIP. ODF smoke management rules are listed in OAR 629-048-0001 through 629-048-0500. The rules specify that the Smoke Management Plan is to be consistent with the Oregon Visibility protection Plan (Section 5.2 of Oregon's SIP) and the Oregon Regional Haze Plan.

In 2014, ODF and EQC adopted changes to the Smoke Management Plan, including particular provisions in the Operational Guidance to protect visibility in Crater Lake National Park and Kalmiopsis Wilderness from prescribed burns. The provisions indicate that if ODF fire district personnel receive a complaint or become aware of a smoke intrusion or smoke incident in either of these areas, the District Forester shall assign a qualified individual to conduct an investigation and document the findings. Since ODF and EQC adopted these additional actions, there have been no prescribed burn intrusions into either Crater Lake National Park or Kalmiopsis. DEQ finds the additional protections are necessary elements to retain as part of Oregon's Long-term Strategy and credits the Oregon Department of Forestry for successfully managing the prescribed burns in these areas.

DEQ is concerned about smoke management practices, including prescribed burning, pile burning, and agricultural burning that contribute to visibility impairment in Class 1 areas. Over the next three years, before the next Regional Haze status reporting, DEQ will engage with the US Forest Service, EPA and state agencies to evaluate and compare smoke management rules in adjoining states in order to develop and adopt uniformly stringent rules to protect visibility.

On March 1, 2019, the Board of Forestry and the Environmental Quality Commission adopted revisions to Oregon Smoke Management Plan, as part of a periodic plan review requirement. These recent rule revisions were the most comprehensive in some time, striking a balance between the need to address the rising risk of catastrophic wildfire in Oregon through the use of prescribed fire, and the need to protect public health and visibility in Class 1 Areas. Numerous changes related to protection of air quality, including new air quality criteria for smoke intrusions and smoke incidents. Historically, no amount of smoke was acceptable within a Smoke Sensitive Receptor Area. The revised rules allow a small level of smoke to enter these areas, but the levels still must comply with the federal 24-hour National Ambient Air Quality Standard for particulate matter and avoid excessive short-duration smoke events. The visibility protection provisions that were previously adopted (OAR 629-048-0130) remain in effect.

Two main objectives of the Smoke Management Plan are to minimize smoke emissions from prescribed burning and promote development of techniques that minimize or reduce emissions, such as utilization of forestland biomass. When prescribed burning is used, land managers are encouraged to employ the emission reduction techniques described in OAR 629-048-0210 to ensure the least emissions practicable. In the next few years, DEQ staff will be working to provide information on alternatives to burning such as clarifying permit requirements for air curtain incinerators and promoting non-burn alternatives.

Oregon, like many western states, is prone to wildfires and in order to reduce the risk of catastrophic wildfires, forest managing agencies conduct forestry prescribed burning. Beyond the hazardous fuel reduction benefits, prescribed burning has many ecological & silvicultural benefits. Underburning is typically used to maintain forest health through reduction of understory fuels and broadcast burning is used for habitat restoration and fuels reduction purposes.

Pile burning accounts for the majority of forestry prescribed burning in Oregon. While important to maintain prescribed burning as one important tool in forest management, DEQ will be working to reduce emissions by promoting alternatives to pile burning. One of those alternatives is the use of air curtain incinerators. When used to dispose of clean woody debris an ACI will increase combustion efficiency especially when the alternative is outdoor pile burning. An ACI operates by forcefully projecting a high velocity of air across an open combustion chamber in which clean wood is loaded. The “air curtain” that is created in this process traps unburned particles (smoke) under it where it is re-burned. Currently, these incinerators require a Title V permit. A proposed EPA rule change could remove the requirement for “other solid waste incineration” from needing a Title V permit. This proposed rule change is only for the OWSIs and is not for the “commercial and industrial solid waste incineration.” In Oregon, most sources are CISWIs. Permitting for ACIs can be complex so DEQ is working to simplify the process. In 2020, DEQ adopted rule amendments to allow issuance of general permits for similar Title V sources. (Administrative Order No. DEQ 7-2020).

Another way to reduce emissions from prescribed burning is by burning fewer piles and using some other non-burn alternative. Non-burn alternatives include lop and scatter, crushing, piling, chipping, and removal. According to the National Cohesive Wildland Fire Management Strategy, non-burn fuel treatments involving mechanical, biological, or chemical methods offer many advantages in terms of greater control over the outcome and reduced risk of unintended consequences. The disadvantage is usually higher economic cost, which in some cases can be offset by active economic markets for the byproducts of the treatment. DEQ is currently working to establish a team of specialists to examine biomass utilization as an alternative to pile burning in an effort to reduce emissions, protect public health, and maintain good visibility. Starting in 2021, DEQ will host a series of biomass working group meetings which will include representation from other state and regulatory agencies, industry experts, and biomass stakeholders. The goal of this working group is to:

- Understand the regulatory authority, process complexities, operational limitations and barriers related to biomass utilization;

- Understand associated environmental impacts that exist or have the potential to exist; and
- Identify needs and opportunities related to biomass utilization.

With many of Oregon's Class 1 visibility areas being located near active forestlands, DEQ believes that the promotion and utilization of ACIs and non-burn alternatives, including biomass utilization, has the potential to improve visibility in these areas.

In 2022 and 2023, DEQ will be administering multiple grants for community response planning and implementation of alternatives to burning. The passage of Senate Bill 762 – the Omnibus Wildfire Bill - by the 2021 Oregon Legislature made this funding available and provided additional resources to DEQ. DEQ will also use a portion of this funding to contract with research institutions and gather new information about emission factors, source testing and best practices for alternatives to burning.

4.6.2 Area Source Strategy: Residential Wood Heating

Residential wood burning is a public health concern as well as a contributor to regional haze. DEQ will continue and expand the following regulatory and incentive programs to reduce emissions from residential woods combustion:

- Oregon's HeatSmart program requires uncertified stoves to be removed at the time of home sales for the whole state. DEQ intends to improve and update this program through a rulemaking in 2023.

- DEQ administers community grants biennially authorized by the Oregon Legislature that pay for wood stove changeouts to natural gas or electric-powered home heating devices in communities for which fine particulate matter pollution has been identified as a major source of wintertime air pollution.

- In 2019, DEQ partnered with Klamath County and successfully received an EPA Targeted Airshed Grant of $1.8 million. From this grant, DEQ expects permanent reduction of emissions from residential wood combustion by converting wood-burning residential heating devices with non-wood burning devices such as gas inserts and ductless heat pumps.

DEQ also intends to pursue resources and partnerships to implement recommendations from DEQ's September 2016 report to the Oregon Legislature: Woodsmoke in Oregon: House Bill 3068 – 2015. Those top recommendations were community funding to implement woodsmoke reduction programs, sustained funding for woodstove changeout programs, and statewide education on the health effects of excessive woodsmoke. DEQ intends to continue partnerships with other state and local agencies, such as DEQ's participation in the Multnomah County Woodsmoke Working group in 2021.

DEQ partnered with Oregon State University in 2021 to conduct a statewide survey of residential heating. DEQ intends to use the results from this survey to improve Oregon's 2020 emission inventory.

4.6.3 Area Source Strategy: Agricultural Open Burning

DEQ's Open Burning and Smoke Management staff have started a collaborative effort with ODF, ODA and the Oregon State Fire Marshal. Over the next few years, DEQ will lead this group in assessing each agency's current rules and regulatory gaps, create process documents, and develop shared messaging campaigns to promote alternatives to and best practices for burning. In addition, DEQ intends to update the Open Burning rules to clarify how DEQ delegates responsibilities and enforcement to other agencies.

Agricultural open burning takes place across the state, except if prohibited by local jurisdictions. The amount of this burning is not well documented and DEQ has found little reliable information on daily burning activity in most areas of the state. DEQ tends to assume that emissions estimates of general outdoor burning include agricultural open burning. DEQ's Open Burning and Smoke Management staff have started a collaborative effort with ODF, ODA and the Oregon State Fire Marshal. Over the next few years, DEQ will lead this group in assessing each agency's current rules and regulatory gaps, create process documents, and develop shared messaging campaigns to promote alternatives to and best practices for burning. In addition, DEQ intends to update the Open Burning rules to clarify how DEQ delegates responsibilities and enforcement to other agencies.

There are two main types of agricultural related burning, "agricultural open burning" and "field burning." Agricultural open burning means the open burning of any agricultural waste except as provided in OAR 340-264-0040(5). Open Field Burning means burning of any grass seed or cereal grain crops, or associated residue, including steep terrain and species identified by the Director of Agriculture, or any "emergency" or "experimental" burning, as identified in OAR 603-077-0105(29). The majority of agricultural field burning in Oregon is associated with grass seed and cereal grain production. This burning is concentrated in specific locations during the summer months, with the majority in the Willamette Valley (about 15,000 acres) and smaller amounts in central and eastern Oregon in Jefferson and Union counties.

The Willamette Valley burning is controlled under the smoke management program operated by the Oregon Department of Agriculture (ORS 468A.590). ODA field burning rules are listed in OAR Chapter 603, Division 77, OAR Chapter 837 Division 110, and OAR Chapter 340, Division 264. The rules apply to areas lying between the crest of the Coastal Range and the crest of the Cascade Range (in the counties Multnomah, Washington, Clackamas, Marion, Polk, Yamhill, Linn, Benton and Lane). ODA's rules indicate that open field burning shall be regulated in a manner consistent with the Oregon Visibility Protection Plan.

Jefferson and Union county field burning is controlled through smoke management programs established by county ordinance and operated at that level. These county programs have requirements to avoid burning upwind of nearby Class 1 areas when smoke dispersion is poor and could impair visibility.

Oregon has prioritized the reduction of agricultural field burning while providing alternative methods of field sanitation and utilization of commercial residues to control, reduce, and prevent air pollution from field burning. Since the previous Regional Haze SIP revision, ODA's agricultural field burning program has decreased significantly, with maximum burnable acres reduced to 15,000 from 50,000 acres. Additionally, counties listed in ORS 468A.560 are no longer able to participate in propane flaming or stack burning. ODA encourages growers to utilize many different techniques which minimize emissions from field burning, including rapid ignition and ensuring field residues are dry and in good burning condition.

4.6.4 Area Source Strategy: Agricultural Sources

DEQ recognizes that agricultural sources, including dairies and other confined animal feeding operations, are potentially the major source for the visibility impairments observed at Strawberry Mountain Wilderness, Eagle Cap Wilderness, and Hells Canyon Wilderness in the wintertime months. This sector also seems to have an impact on visibility in the Columbia River Gorge National Scenic Area in the wintertime months. DEQ will work with stakeholders and the Oregon Dept. of Agriculture during this planning period in order to identify potential agricultural sector reductions for the next planning period.

DEQ recognizes that ammonium nitrate from dairy operations is probably a significant contributor to regional haze, particularly in the winter in the Columbia Gorge. In the last two decades, DEQ, the Columbia River Gorge Commission, Southwest Washington Clean Air Agency, the Oregon Department of Agriculture, the Oregon Legislature and others have put resources toward studying visibility impacts from agriculture and refining our understanding of sources, emissions, and best management practices.

The 2007 Oregon Legislature passed Senate Bill 235 that allowed the Oregon EQC limited authority to regulate agricultural operations and established a Task Force on Dairy Air Quality; specifically, the EQC could “implement a recommendation of the Task Force on Dairy Air Quality…for the regulation of dairy air contaminant emissions.”[32] SB 235 charged the Task Force with studying emissions from dairy operations, evaluating available alternatives for reducing emissions, and presenting findings and recommendations to DEQ and ODA.

In 2008, the Oregon Diary Air Task Force released its findings and recommendations. Among the Task Force recommendations were to develop a program based on Best Management Practices, such as manure management, feed practices and installation of waste management systems (e.g. digesters). The task force recommended a voluntary Phase I, followed by a mandatory Phase II. The Task Force recommended that DEQ, ODA, Oregon Health Authority and research institutions provide technical assistance so agricultural operations can develop expertise in BMPs that reduce ammonia, methanol and odors, as well as educational material and outreach to the general public and neighboring communities. Based on the approach of adjacent states, about 45 dairies in Oregon would be subject to newly developed regulations.

In 2017, the Oregon Dept. of Agriculture, also tasked by the Oregon Legislature, completed a comparison of practices of two large Oregon dairies in the Columbia Gorge with programs in Idaho and Washington. ODA found the practices of the two dairies met the standards in adjoining states, but also recommended practices and technologies that could be explored as opportunities to mitigate dairy air emissions. Those recommendations included optimizing digester operations, lagoon storage covers and bacterial or other substrate additions, installation of bio-filters to capture and treat emissions, and opportunities for air sequestration through crop production.

DEQ has brought requests for funding a Dairy Air program to the Oregon Legislature twice but has not yet been successful in securing funding for such a program. DEQ will continue partnering with ODA and other stakeholders to develop a Dairy Air Quality permitting program based on implementation of best practices.

DEQ will also develop and refine the state’s ammonia emission inventory and will seek EPA’s assistance, as necessary.

[32] ORS 468A.020(2)(c)

4.6.5 Area source strategy: Rail and Airports

The majority of airport emissions, and therefore visibility impairment, are attributable to airplane takeoffs and landings. These emissions fall under the scope of Federal, not state, environmental regulation. However, there are two significant actions that will reduce emissions associated with ground support equipment and non-road construction equipment at the Port of Portland. As described briefly above, the Port is a part of the Clean Air Construction Coalition which will reduce diesel emissions associated with Port construction projects. In addition, the Port has plans to electrify its ground operations to the maximum extent possible and has achieved significant reductions already.

Locomotives are responsible for 8% of diesel particulate matter emissions statewide. While new locomotive engines are regulated at the Federal level, Oregon does have authority to adopt in-use standards. We are currently tracking California Air Resources Board policies in this area. If California adopts new in-use locomotive rules DEQ will consider the impacts of those rules on emission inventories and visibility impairment in Oregon. DEQ may consider taking similar action to avoid the shifting of California's oldest locomotives across the border.

4.6.6 Area Source Strategy: Volatile Organic Compounds

DEQ did not specify Volatile Organic Compounds as Round 2 Regional Haze pollutants. However, the apportionment charts in Section 2.5 show that organic carbon from US anthropogenic sources contribute to visibility impairment on a similar scale to ammonium nitrate and ammonium sulfate. In addition, DEQ is concerned that VOCs are significant contributors to other secondary pollutants such as ozone and toxic air contaminants, as well as visibility-impairing particular matter. DEQ plans to undertake several regulatory and incentive-based efforts in the next three years to reduce VOC emissions from area sources. DEQ's Air Quality Division is working with DEQ's Materials Management Program to implement the agency's Toxics Reduction Strategy, which includes reducing VOCs in building materials, encouraging pollution prevention practices, and promoting product substitutions such as water-based automotive paints. DEQ also expects to undertake rulemaking, preferably at the regional level with Washington and Idaho, that will require reducing VOCs in consumer products and architectural, industrial and maintenance coatings; separate rules will require upgrades to vapor recovery systems at gasoline dispensing facilities.

4.7 Implement SIPs and Proactive Programs

DEQ and LRAPA will continue to meet Clean Air Act responsibilities to enforce strategies and report progress in PM Maintenance and Nonattainment areas. The strategies to reduce PM in these areas are directed at achieving health-based NAAQQS, but DEQ expects those strategies will improve visibility as well. Oregon's PM10 Maintenance areas are: Grants Pass, Medford, and Klamath Falls. Areas designated nonattaining for PM2.5 are Klamath Falls and Oakridge. DEQ will be undertaking the Klamath Falls PM 2.5 Maintenance Plan in 2021 with expected completion by early 2022.

Two communities in Oregon voluntarily participate in EPA's PM Advance Program. DEQ supported these communities through the PM Advance application process and will continue to work closely with them. PM Advance is a voluntary and proactive program for communities where PM 2.5 measurements often exceed the NAAQS, but are not yet designated nonattaining. Air quality in the urban growth boundaries of Prineville and Lakeview often does not meet the NAAQS and these areas have ongoing winter-time PM2.5 issues. Both areas entered the PM Advance Program in 2014, organizing advisory committees develop strategies for compliance with the PM2.5 NAAQS.

These strategies include local ordinances to reduce wood smoke, public education and outreach, voluntary or mandatory wood stove advisories with curtailment of wood stove use during poor air quality days and other measures. Most of the focus and effort in PM Advance is local, in partnership with DEQ, although EPA will occasionally, if invited, participate in local Air Quality Committee meetings.

Both areas have had many wood stoves removed and replaced with non-wood burning devices or replaced with new and certified wood stoves. Lakeview has had over 100 wood stove replacements in the last several years, as funding was available. There is no natural gas available in Lakeview so it is more of a challenge to offer non-wood burning heating devices. Prineville has had fewer than 25 replacements, but has reduced burning in burn barrels and also has implemented a reduced cost or free green woody waste collection events.

Lakeview was successful in past years lowering PM10 measurements -- now well below the standard – and DEQ is confident this community will continue making progress on PM 2.5 through the Advance program. Prineville has shown a strong trend of compliance with the NAAQS; even if Prineville withdraws from PM Advance, DEQ expects the community would continue to convene their Air Quality Committee and implement woodsmoke reduction strategies.

4.8 International emissions

WRAP modeling indicates that a large percentage of regional haze pollutants measured in Oregon originate internationally. DEQ recognizes that international emissions contributing to US visibility impairment is not new, but WRAP's modeling suggests that the portion of visibility impairment attributed to international emissions will continue to increase in the coming decades. For example, WRAP's modeling of visibility at the Eagle Cap/Strawberry Mountain IMPROVE monitor, shows approximately one deciview impairment from international emissions in 2028 and approximately 3 deciviews in 2064. The 2017 Regional Haze Rule requires that states develop and implement comprehensive plans to reduce human-caused regional haze in designated areas. States also must calculate and work towards interim, short-term progress goals, with a long-term goal of returning targeted areas to their natural visibility conditions by 2064. Natural conditions have been defined and were agreed upon previously and Oregon is planning to implement strategies to achieve that goal. The increased contribution of international emissions will cause us to fail unless those emissions are mitigated.

Oregon disagrees with the suggested approach of changing the target, and thus the glidepath, to accommodate the resulting impairments. The international emissions that obstruct our view of Oregon's 12 Class 1 areas also form background particulate aerosols ($PM_{2.5}$) and cause ozone exceedances. The Clean Air Act places the responsibility to address international pollution with the federal government and EPA, who have the jurisdiction and authority which states lack to legislate, negotiate and implement policies that reduce international emissions transport.

The success of Oregon's plan as well as the success of most other western states' to meet natural background conditions that is envisioned by the Clean Air Act, depend on the EPA to do its share and address international transport. Most of the increase in international transport is related to sulfate and nitrates, suggesting increased use of fossil fuels. EPA should consider strengthening aircraft standards, ships and other marine vessel standards and climate targets that will rapidly phase out fossil fuel dependence in the US and internationally.

Oregon's Regional Haze SIP is dependent on the federal government to successfully reduce the impact of international transport. Oregon commits to track progress and report on the federal share in its future plan updates.

5 Uniform Rate of Progress

In this section, DEQ demonstrates that Reasonable Progress Goals for 2028 will meet a Uniform Rate of Progress toward natural visibility goals by 2064. DEQ has demonstrated based on the required analysis of the four factors, that Oregon's Round 2 regional haze Long-term Strategy contains all "emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy" and therefore meets the requirements of 40 CFR 51.308(f)(3)(ii)(A). In particular, with a screening factor, Q/d > 5.00, DEQ called in 31 facilities for analysis that contribute 80% of the total Q from major sources for all Oregon Class I Areas, including sources not located in Oregon. Several facilities that DEQ called in agreed to lower PSELs such that Q/d < 5.00, leaving 23 facilities to undergo four factor analysis. DEQ set a cost effectiveness threshold at $10,000 ton, which led to controls or emission reductions at 17 facilities, encompassing 43 emission units.

5.1 Reasonable progress goals for Class I Areas

Table 5.1 shows Reasonable Progress Goals for 2028 at each of the Oregon IMPROVE sites. **Error! Reference source not found.** through 10 illustrate the Regional Haze Uniform Rate of Progress glidepath and the 2028 projections at each of Oregon's IMPROVE sites, and sites in Washington and California that are affected by Oregon sources. The 2028 projections are based on WRAP modeling of the second Potential Additional Controls scenario, which represents regulations on the books as of 2020 plus stationary source controls recommended from DEQ's review of initial four factor analyses submittals and incorporated into Oregon's Long-term Strategy.

Generally, the predicted 2028 PAC2 visibility is lower than the URP glideslope for sites in the northern part of the region, including the northern and eastern Oregon IMPROVE sites (MOHO, STAR, and HECA), and two sites in Washington affected by Oregon sources (MORA and WHPA). Sources in the central and southern part of the region exhibit an opposite trend, and the PAC2 projections lie above or on the glideslopes. These IMPROVE sites include THSI, CRLA, and KALM in Oregon, and REDW and LABE in northern California, which are affected by Oregon sources.

Table 5-1: 2028 Reasonable progress goals for Oregon IMPROVE sites in deciviews, from WRAP TSS.

		Most Impaired Days (MID)				Clearest Days			
		Observed		Modeled RPG	Estimated	Observed		Modeled RPG	No degradation
		Baseline		PAC 2	Nat. Conditions	Baseline		PAC2	Limit
	Class I areas Served	2000-2004 DV	2014-2018 DV	2028 DV	2064 DV	2000-2004 DV	2014-2018 DV	2028 DV	2064 DV
HECA	Hells Canyon	16.51	12.33	11.66	6.57	5.52	4.00	3.79	5.52
STAR	Eagle Cap Strawberry Mt.	14.53	11.19	10.47	6.58	4.49	2.79	2.62	4.49
MOHO	Mt. Hood	12.10	9.27	8.50	6.59	2.17	1.39	1.29	2.17
THSI	Mt Washington Mt Jefferson Three Sisters	12.80	11.28	10.86	7.30	3.04	2.61	2.53	3.04
CRLA	Crater Lake Diamond Peak Mt. Lakes Gerhart Mt.	9.36	7.98	7.72	5.16	1.69	1.05	0.98	1.69
KALM	Kalmiopsis	13.34	11.97	11.63	7.78	6.27	5.90	5.84	6.27

The following figures are organized geographically, from north to south, primarily along the alignment of the Cascades, to highlight regional trends in extinction, glideslopes, and modeled 2028 PAC2 projections.

Figure 5-1: MORA URP Glidepath and Modeled 2028 PAC2.

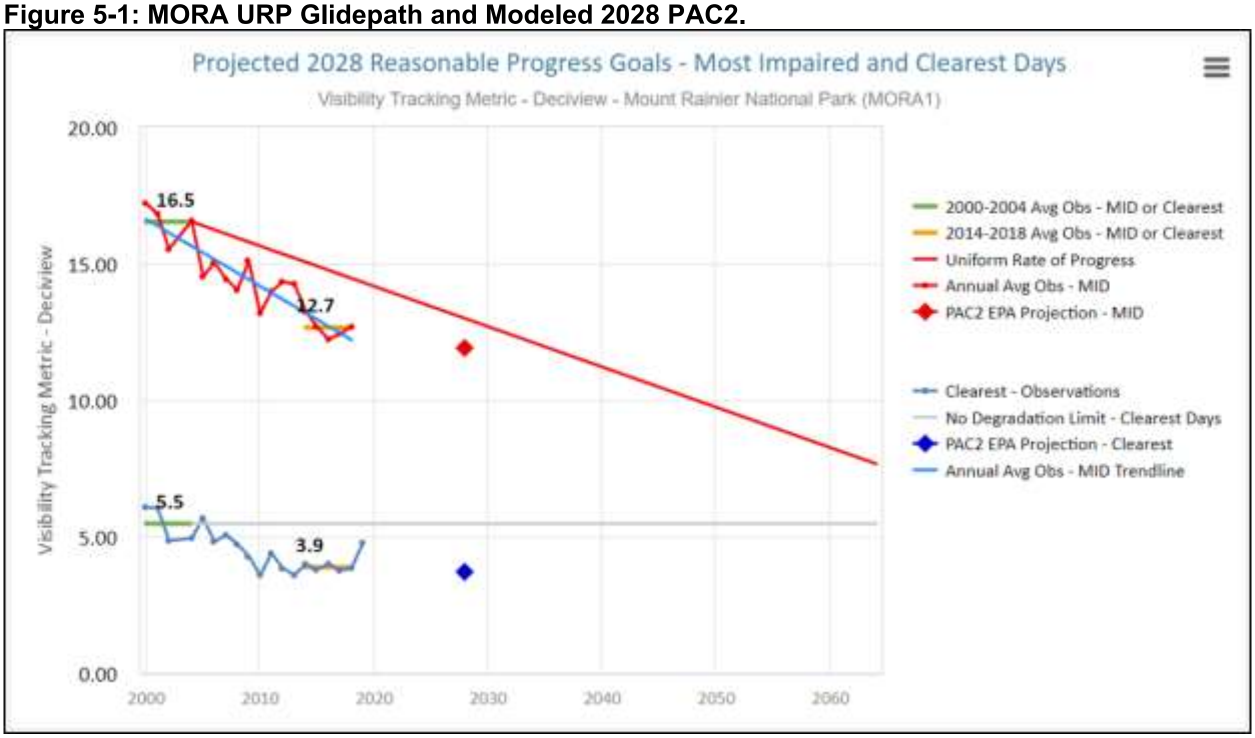

Figure 5-2: WHPA URP Glidepath and Modeled 2028 PAC2.

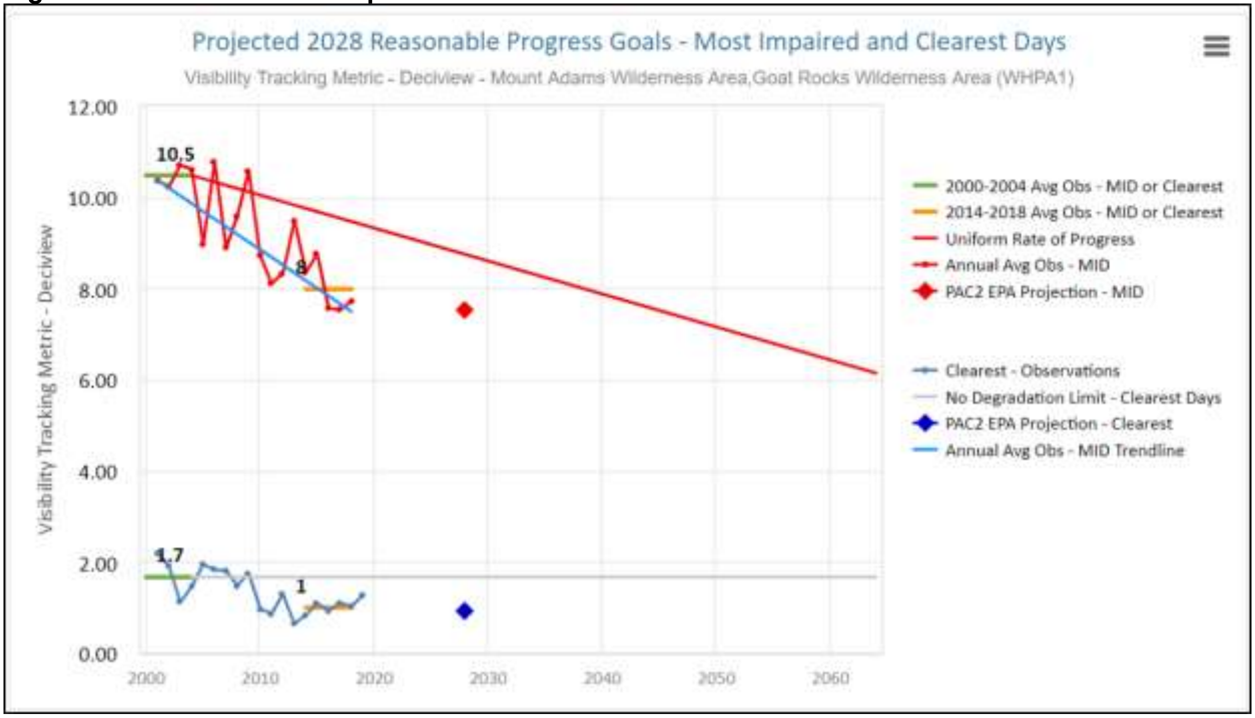

Figure 5-3: HECA URP Glidepath and Modeled 2028 PAC2.

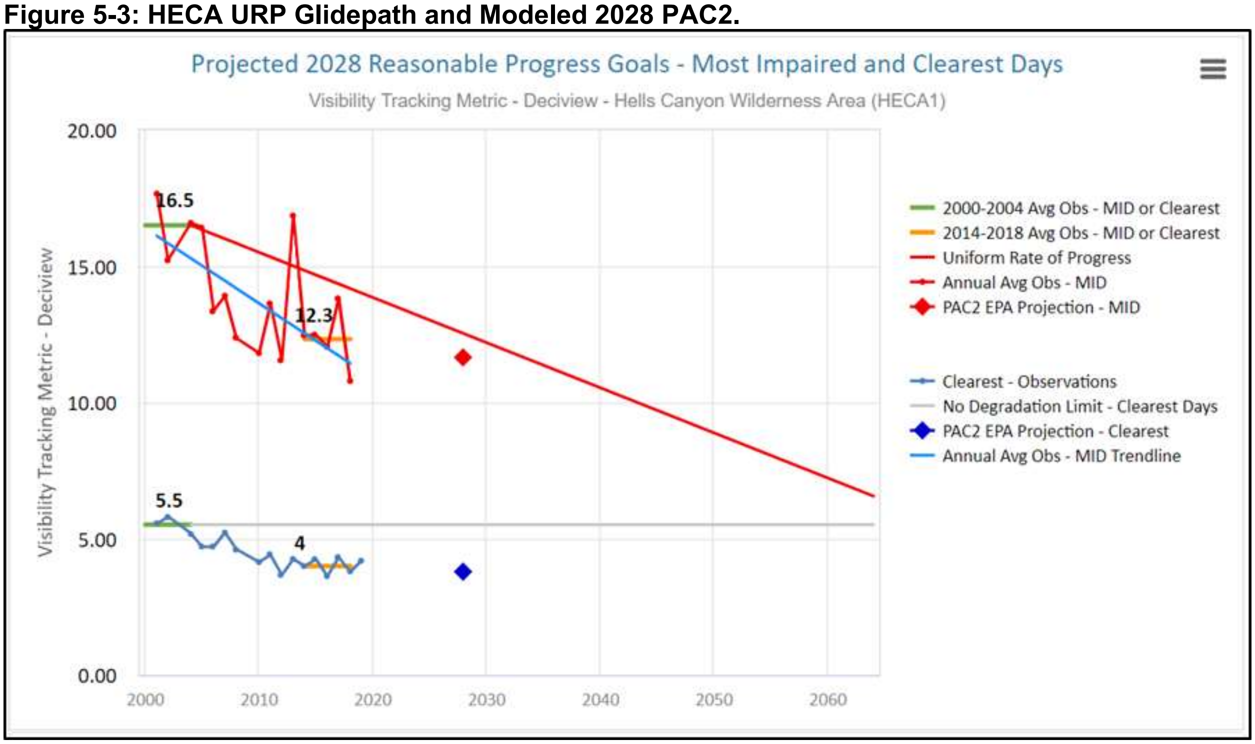

Figure 5-4: STAR URP Glidepath and Modeled 2028 PAC2.

Figure 5-5: MOHO URP Glidepath and Modeled 2028 PAC2.

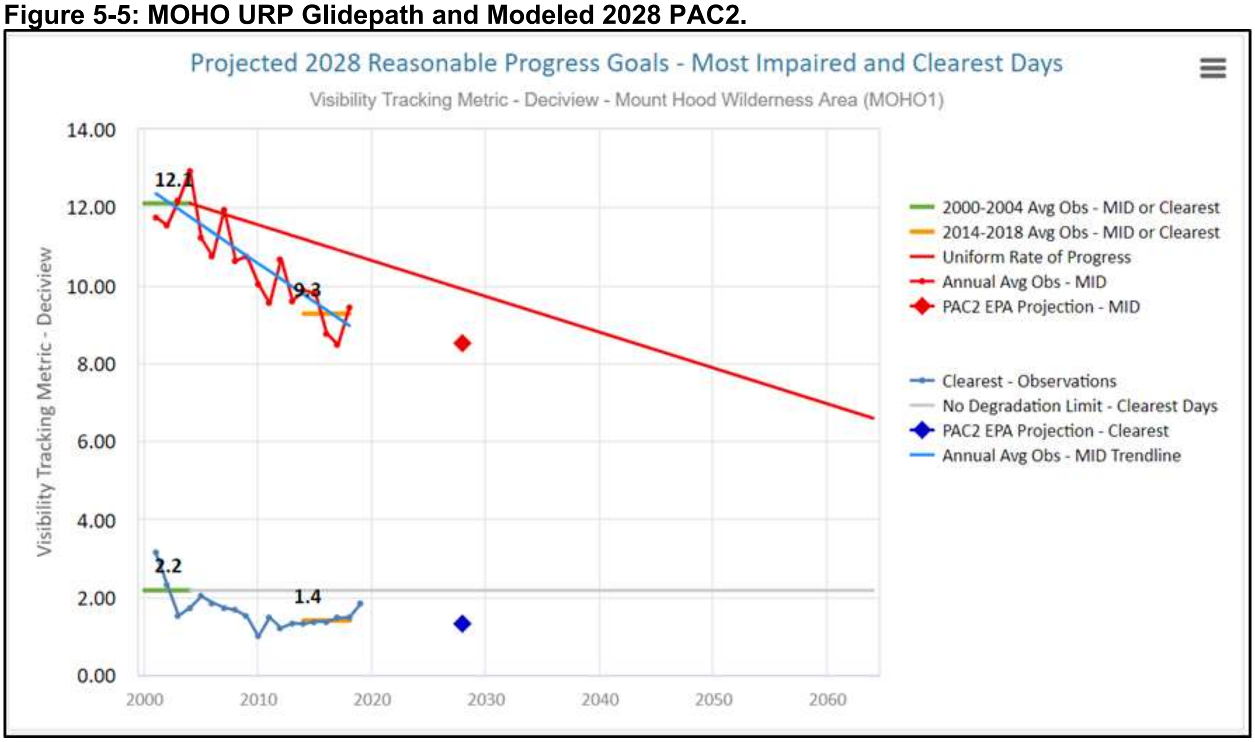

Figure 5-6: THSI URP Glidepath and Modeled 2028 PAC2.

Figure 5-7: CRLA URP Glidepath and Modeled 2028 PAC2.

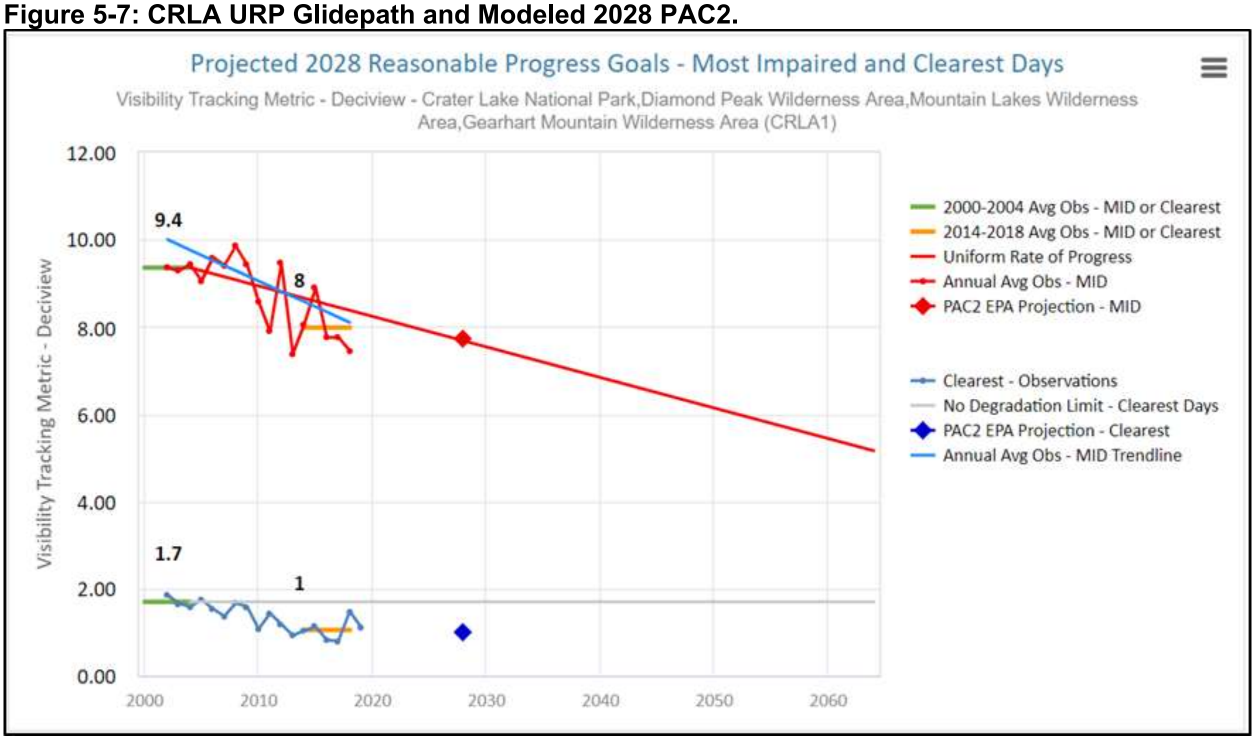

Figure 5-8: KALM URP Glidepath and Modeled 2028 PAC2.

Figure 5-9: REDW URP Glidepath and Modeled 2028 PAC2.

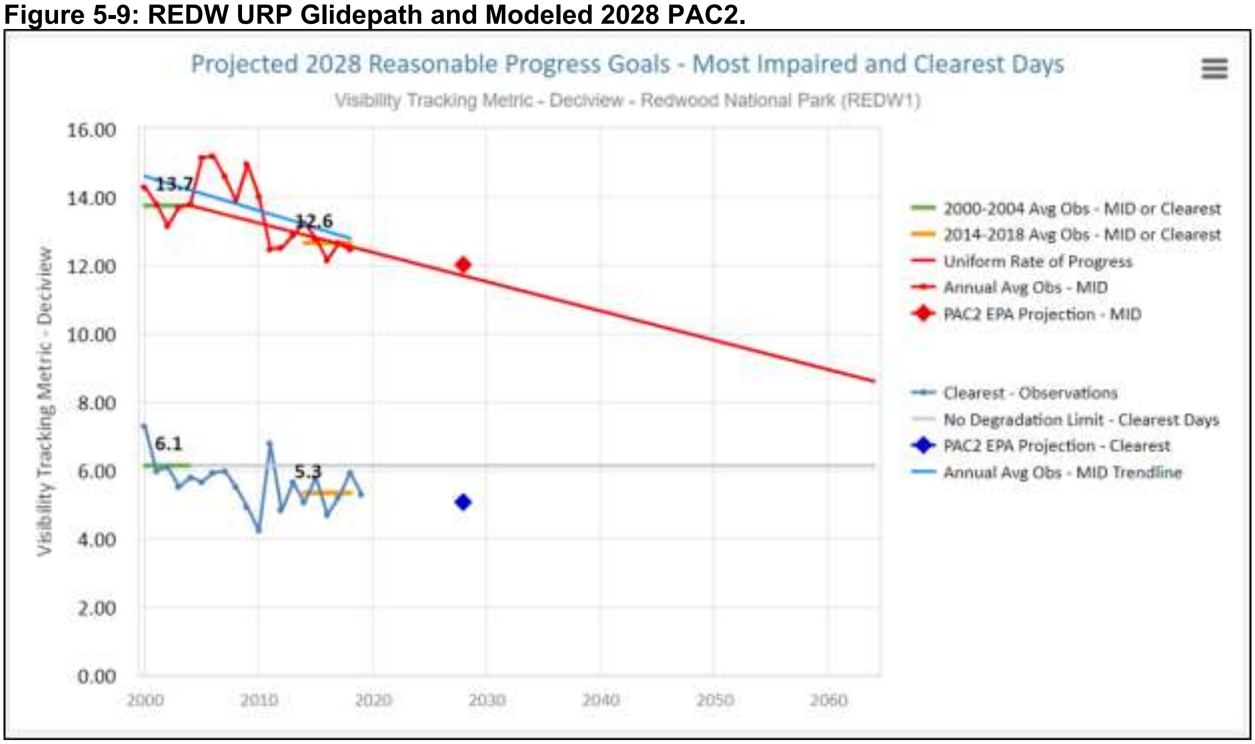

Figure 5-10: LABE URP Glidepath and Modeled 2028 PAC2.

5.2 Glidepath policy choice

The URP glidepath originates with the EPA-calculated 20% most impaired days using observations from the IMPROVE monitoring site that represents either a single Class 1 area, or multiple areas. The URP glidepath starting point is the MID for the 2000-2004 5-year baseline period and the glidepath slope is the straight line drawn to estimated natural conditions in 2064. In the second regional haze planning period, the default glidepath endpoint uses natural conditions estimates based on the 15-year average of natural conditions on most impaired days in each year 2000-2014.

For each IMPROVE monitor site, there are three options which estimate projected visibility conditions in 2028. The projection options are: the EPA Projection, the EPA Projection without fire, and the EPA Projection using Modeled MID. For the 2028 projections, DEQ found the presence or absence of fire effects to be relatively small. For that reason, DEQ chose the EPA 2028 projected visibility without a fire correction.

The WRAP TSS site also provides calculations for two alternative glidepath end point projections at 2064. The glideslope options are: no adjustment; adjust 2064 natural conditions by adding International Anthropogenic emissions; or adjust 2064 natural conditions by adding International Anthropogenic and Wildland Prescribed Fire emissions. The 2017 Regional Haze Rule allows a state to select the default glidepath slope or one of the alternatives for the individual Class 1 areas. DEQ chose to compare 2028 projected emissions under the Potential Additional Controls 2 scenario to the unadjusted glide path.

DEQ chose these options because they best represent the conditions that will be used for Oregon’s Long-term Strategy to improve visibility. Adjusting the glidepath is conceding to a future that has poorer visibility, more pollution and is less healthy. DEQ considers the Regional Haze plan as partnership between states, tribes and the federal government. DEQ accepts responsibility to address emissions from sources within DEQ's direct control and relies on its partners to do their share. DEQ's policy decision to represent URP as an unadjusted glidepath has some effect on whether 2028 visibility projections fall slightly below or slightly above the glidepath (primarily at the central and southern Oregon IMPROVE sites), but DEQ did not base regulatory stationary source control decisions on the URP. DEQ based control decisions on the factors described in Section 3 of this plan and EPA's 2019 Regional Haze guidance that visibility projections below the glidepath do not provide "safe harbor" for sources.

6 Consultations, public comment, and responses

6.1 Consultations with Tribes

6.1.1 Oregon statutes for state-tribal government-to-government relations

Oregon was the first state to pass a state-tribal government-to-government relations law. In 2001, Senate Bill 770 (SB 770) established a framework for communication between state agencies and tribes. Effective government-to-government communication increases our understanding of tribal and agency structures, policies, programs, and history. These state and tribe relations inform decision makers in both governments and provides an opportunity to work together on shared interests. The state statute created from SB 770[33] is ORS 182.162-168.

State agencies also follow Executive Order EO-96-30, established in 1996, that defined a process to "assist in resolving potential conflicts, maximize key inter-governmental relations, and enhance an exchange of ideas and resources for the greater good of all of Oregon's citizens." Agencies responded to the executive order by presenting interest statements to the Governor and tribal government. DEQ developed a Tribal Government-to-Government Relations Program in 1996 following the signing of EO 96-30. In 2001, when the Oregon Legislature approved Senate Bill 770, this institutionalized the executive order into law.

DEQ's official response to the directives of Senate Bill 770 is contained in our tribal relations policy. The statement expresses DEQ's commitment to maximize inter-governmental relations between the agency and the nine federally recognized tribes in the State of Oregon.[34]

The US Environmental Protection Agency is also an important participant in government-to-government relations between DEQ and the tribal governments. EPA has a responsibility to protect and restore the lands and environmental treaty resources (on-and-off reservation) of tribes. Regulation of federal environmental laws on tribal lands is also the responsibility of EPA. However, tribes may seek direct delegation authority from EPA to carry out federal and tribal environmental regulations on tribal lands. DEQ participates in a partnership with EPA and tribal

[33] http://nrc4tribes.org/files/Tab%209_9H%20Oregon%20SB770.pdf
[34] https://www.oregon.gov/deq/about-us/Pages/tribal.aspx

governments in carrying out their respective responsibilities for protecting and enhancing Oregon's environmental resources.

For this Round 2 Regional Haze plan, DEQ's Director initially reached out to Oregon's nine federal recognized tribal governments via letter in December 2019. DEQ, through its Director and tribal liaison continued to offer consultation at multiple points as DEQ was developing Round 2 strategies and methods. DEQ staff have updated tribal staff on the Round 2 Regional Haze process over the last two years at bimonthly DEQ-Tribal roundtable meetings and by presenting statute updates at the Legislative Commission on Indian Service Natural Resource Cluster meetings. DEQ staff also engaged with tribes through the regional modeling forum convened by WRAP, in particular the Tribal Data Work Group.

6.1.2 Western Regional Air Partnership

The Western Regional Air Partnership 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.[35]

The Tribal Data Work Group of the WRAP convened monthly from September 2018 to January 2020 and developed a WRAP Communication Framework for Regional Haze Planning, reviewed several data products of interest to the work group. That information is located on the WRAP Tribal Data Work Group website: https://www.wrapair2.org/TDWG.aspx

6.2 Consultations with States

State-to-State consultation followed the Long-term Strategy section of the 2017 Regional Haze Rule [40 CFR 51.308(f)(2)(ii)], which states:

> "The State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class 1 Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.
>
> (A) The State must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.
>
> (B) The State must consider the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class 1 Federal area.
>
> (C) In any situation in which a State cannot agree with another State on the emission reduction measures necessary to make reasonable progress in a mandatory Class 1 Federal area, the State must describe the actions taken to resolve the disagreement. In reviewing the State's implementation plan, the Administrator will take this information into account in determining whether the plan provides for reasonable progress at each mandatory Class 1 Federal area that is located in the State or that may be affected by emissions from the State. All substantive interstate consultations must be documented."

[35] https://www.wrapair2.org/

DEQ participated in monthly calls with EPA Region 10 and Idaho, Washington, and Alaska agencies preparing Regional Haze plans. In addition, DEQ participated in regular calls with WESTAR states as organized by WRAP's Regional Haze Planning group. Those conversations are archived here: https://www.wrapair2.org/RHPWG.aspx. Finally, DEQ also had individual consultations with Idaho, Washington, California and Nevada regarding approaches to four factor analysis and general SIP preparation.

6.3 Consultations with Federal Land Managers

6.3.1 Regional Haze Rule

40 CFR 51.308(i) State and Federal Land Manager coordination states:

> (2) The State must provide the Federal Land Manager with an opportunity for consultation, in person at a point early enough in the State's policy analyses of its long-term strategy emission reduction obligation so that information and recommendations provided by the Federal Land Manager can meaningfully inform the State's decisions on the long-term strategy. The opportunity for consultation will be deemed to have been early enough if the consultation has taken place at least 120 days prior to holding any public hearing or other public comment opportunity on an implementation plan (or plan revision) for regional haze required by this subpart. The opportunity for consultation on an implementation plan (or plan revision) or on a progress report must be provided no less than 60 days prior to said public hearing or public comment opportunity. This consultation must include the opportunity for the affected Federal Land Managers to discuss their:
>
> (i) Assessment of impairment of visibility in any mandatory Class 1 Federal area; and
> (ii) Recommendations on the development and implementation of strategies to address visibility impairment.
>
> (3) In developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers.
>
> (4) The plan (or plan revision) must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required by this subpart, including development and review of implementation plan revisions and progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class 1 Federal areas.

6.3.2 Consultations with Federal Land Managers in advance of draft SIP review

Federal Land Managers were part of the WRAP quarterly Regional Haze Planning meetings. DEQ met individually with two federal agencies - US Forest Service and National Park Service – on multiple occasions before providing the draft SIP to those agencies for comment.

6.3.2.1 National Park Service

DEQ met with the National Park Service initially on January 28, 2020. DEQ described the agency's overall approach to source screening and review of four factor analyses at that point, which was one month after DEQ sent initial four factor analysis letters to facilities, and after the initial call with facilities on January 9, 2020.

DEQ held a subsequent meeting with National Park Service on September 25, 2020. DEQ described the Q/d screening process, the adjustments for 30 year equipment life, the bank prime rate, and the facilities that had screened out of additional analysis at that point. DEQ also discussed the probable cost effectiveness threshold of $10,000 per ton of pollutant removed. NPS affirmed that these factors and this approach aligned with NPS's approach to reviewing four factor analyses. DEQ followed up by emailing all the four factor analyses to NPS for the 17 facilities where controls were still in consideration.

DEQ met again with NPS on February 19, 2021. EPA Region 10 was also present at this meeting. DEQ described the Regional Haze SIP status and reviewed the timeline for revising Oregon's Chapter 340 Division 223 rules. DEQ described how the Division 223 rulemaking would codify the Q/d screening and four factor analysis requirements used in Round 2 Regional Haze, as well as provide the authority for DEQ to issue orders to facilities for mandatory and enforceable emission reductions. DEQ also received NPS's consultation expectations and described the timeline DEQ considered ideal for receiving FLM comments while allowing DEQ to submit the Regional Haze SIP to EPA during summer 2021.

DEQ met NPS two more times, in addition to the May 27, 2021, draft SIP presentation meeting, on June 30 and July 15, 2021. At the June 30 meeting, NPS stated they did not consider the required 60-day consultation period to have started because the draft SIP did not include the final control and emission reduction requirements for the facilities that underwent four factor analysis. As NPS had requested, DEQ reviewed the timeline for the Division 223 rulemaking underway and its relationship to the SIP. DEQ explained that the current rulemaking would give DEQ authority to issue orders to facilities, requiring that they install controls or otherwise reduce emissions. DEQ explained that the proposed rules would require DEQ to issue the orders by August 9, 2021, allowing DEQ sufficient time to incorporate the orders in the SIP that DEQ wished to notice in September. DEQ committed to sending NPS updated information about the status of DEQ's facility control findings.

At the July 15 meeting with NPS, DEQ presented a spreadsheet that summarized DEQ's findings for each of the 32 facilities subject to four factor analysis and any tentative agreements with facilities if they had been reached. DEQ noted the facilities with whom DEQ was still negotiating and where DEQ would send updated information to NPS. NPS requested all documentation related to DEQ's analysis of facility-submitted FFA information for those facilities that had not already tentatively agreed to reduce plant site emission limits as a means to comply with the then-proposed Division 223 rules. On July 23, 2021, DEQ made all files NPS requested available to NPS on a Google drive, including an updated summary spreadsheet of DEQ's findings and tentative agreements with facilities about control installation or emission reduction.

6.3.2.2 U.S. Forest Service

DEQ met initially with the U.S. Forest Service on August 21, 2020. DEQ presented our analysis of the visibility impairment data for Class 1 areas. This included a finding that for the Columbia River Gorge, the STARKEY monitor, and Hells Canyon, that the ammonium nitrate levels could potentially be above the glidepath by 2028. The agencies discussed that for all three monitors ammonium nitrate seems to be the pollutant of concern especially in the wintertime months.

DEQ and USFS discussed USFS interest in partnering to better understand the periodic increases in ammonium nitrate levels observed at the Hells Canyon, Starkey, and the Columbia River Gorge National Scenic Area. Such a partnership would include consideration of meteorological conditions, sources, and potential solutions to reduce overall impact on visibility. USFS noted they had conducted passive ammonium monitoring and maintained the necessary monitoring equipment. DEQ and USFS agreed that if such monitoring showed that ammonium nitrate trends in the Gorge differ from the Mt. Hood and Mt. Adams Class I Areas, then both agencies would confer about those discrepancies.

DEQ also reviewed the Smoke Management Plan with USFS and the agencies discussed DEQ's plan to rely on SMP implementation to manage and reduce visibility impacts from anthropogenic burning and smoke. This would be the same management strategy proposed for Round 1 implementation of the Regional Haze Rule. DEQ then reviewed the anticipated timeline for consultations; at the time of the August 2020 meeting, DEQ expected FLM consultation to begin in February 2021.

DEQ met again with USFS on February 24, 2021. At that meeting, USFS summarized their expectations for what DEQ would provide before they would consider the formal 60-day consultation period to have begun. USFS reiterated their interest in improving visibility in the Gorge and asked DEQ to include discussion of Gorge winter-time ammonium nitrate measurements and the likelihood of Gorge visibility benefits from controls that benefit the Mt. Hood CIA. USFS also asked DEQ to consider including a detailed description of the sources included in emissions inventories relied on for modeling. DEQ and USFS also discussed DEQ's decision not the adjust the glidepath to account for prescribed burning. USFS recommended adjusting the glidepath to allow for a likely need to increase prescribed burning to reduce wildfires, while relying on the SMP as a backstop.

6.3.3 Federal Land Manager review of draft State Implementation Plan

DEQ provided a draft of the Round 2 Regional Haze Plan to USFS and NPS on May 5, 2021. DEQ met with NPS and USFS, respectively on May 25 and May 27, 2021 to present the draft SIP, answer questions and receive preliminary feedback.

DEQ received USFS written comments on June 23, 2021. DEQ received comments from NPS in several communications between April 2 and July 15, 2021. DEQ summarizes the dates and topic of NPS comments received in Table 6-1.

Table 6-1: Summary of NPS comment dates and subject matter

Comment Date (2021)	NPS Commenter	Comment Subject Matter
April 2	Debra Miller	FFAs Roseburg Forest Products – Dillard and Biomass One
June 3	Debra Miller	FFAs Roseburg Forest Products – Dillard and Biomass One
July 1	Melanie Peters	Draft SIP, generally
July 1	Don Shepherd	FFA report prepared by All4 for Northwest Pulp and Paper Assoc., covering several facilities. FFA Boise Cascade – Elgin FFA Boise Cascade – Medford

		FFA Cascade Pacific FFA Georgia Pacific – Toledo FFA Georgia Pacific – Wauna FFA International Paper
July 7	Andrea Stacey	FFAs Gas Transmission Northwest Compressor Stations 12 & 13
July 15	Andrea Stacey	Selective catalytic reduction feasibility for compressor stations over variable loads

6.3.4 Federal Land Manager Comments and DEQ Responses

In the following sections, DEQ summarizes FLM comments, responds, and describes what changes, if any, DEQ made to the Regional Haze Plan.

6.3.4.1 US Forest Service

Comment FS-1
Observed changes since Round 1 of the Regional Haze SIP: significant emission reductions made in Oregon over the past decade have resulted in substantial improvements in visibility at all Forest Service Class I Areas within the state.

DEQ Response FS1
DEQ agrees.

Comment FS-2
Lack of site-specific plans to reduce haze at each Class I Area: Include specific analyses and long-term strategies for each individual or group of Class I areas represented by an IMPROVE monitor. For example, include probable locations of contributing sources, seasonality of impacts, identification of haze-contributing source types and which fall under DEQ authority, long-term strategy to reduce haze-causing pollutants for each of these sites, and whether or not these reductions will be sufficient to meet the Uniform Rate of Progress; revise the report to clarify the basis for and the specific plans to reduce haze following the URP for each Class I area, separately.

DEQ Response FS-2
DEQ intends to apply long-term strategies to reduce regional haze forming pollutants statewide. However, DEQ agrees this report would benefit from a discussion of the top haze forming pollutants and sources at each Class I Area or IMPROVE site and how certain elements of the LTS would be particularly applicable at those locations. DEQ provides such a summary in Table 4.1 in Section 4.3, Findings informing Long-term Strategy.

DEQ did consider probable locations of sources in developing the Long-term Strategy, primarily by consulting the Weighted Emission Potential, Extinction Weighted Residence Time, and back trajectory modeling results available on the WRAP TSS site. DEQ chose not to analyze seasonality of visibility impairment in developing the Long-term Strategy since DEQ found that calculating seasonal changes is hampered by gaps in the data available through TSS. DEQ relied on the Round 2 regional haze use of the 20% Most Impaired Days metric to account for removal of non-anthropogenic contributions.

Comment FS-3

Prescribed fire: The SIP implies limitations to prescribed fire based on the amount of fire used in the modeling projections. The 2017 NEI data DEQ used lacks important detail such as the total number of acres burned, the type of burning (pile burning, understory, etc.), fuel type, associated emission factors, and resulting emissions. DEQ states that the agency made corrections to the NEI but does not specify what those corrections were.

The 2017 tons/year PM10 from fires, listed in Table 2.4, converted to estimated PM 2.5 (28,850 tons/year), is three times the PM 2.5 emissions that the ODF Smoke Management Program calculates for 2017 (9,874 tons/year) based on acres burned.

DEQ states that the amount of burning assumed for the 2017 inventory was kept constant for 2028 projections; this conflicts with recommendations from the Governor's Wildfire Response Council. DEQ should correct emissions for 2028 projections or discuss the discrepancies from the Council's recommended future prescribed fire activity.

DEQ Response FS-3
DEQ acknowledges different methodologies used by state agencies and the NEI in attributing emissions to prescribed burning. Generally, DEQ the activity data that DEQ sends to the NEI for prescribed fires includes location, burn type, owner of property, acres and total tons burned, ignition date and time, and some fuel moisture information. DEQ has both collected this data ourselves from ODF and hired contractors to do so.

DEQ acknowledges that USFS, ODF and NEI are not using the same methodologies and emission factors to estimate fire emissions. DEQ can provide more detail on NEI methodology, emission factor estimates and calculations used to estimate fire emissions. In developing the Round 2 Regional Haze Plan and Long-term Strategy, DEQ relied on the consultations that took place in the WRAP regional haze fire working group to address discrepancies and gaps in NEI fire data.
DEQ has included some details about prescribed fire and alternative treatments statewide between 2014 and 2018 in the Five-year Progress Report section of this Round 2 Regional Haze Plan.

Comment FS-4
Adjustment to the Uniform Rate of Progress: Encourage DEQ to adjust the URP for prescribed fire per EPA guidance; disagree that such adjustment is, as DEQ states, "conceding to a future that has poorer visibility, more pollution and is less healthy;" EPA states "These particular types of fires are generally consistent with the goal of making reasonable progress because they are most often conducted to improve ecosystem health and to reduce the risk of catastrophic wildfires, both of which can result in net beneficial impacts on visibility;" DEQ is relying on an unnecessarily restrictive URP and this may place an unfair share of the burden on some to reduce haze.

DEQ Response FS-4
Thank you for the comment. DEQ has chosen to maintain its policy choice not to adjust the glidepath for international emissions or prescribed fire.

Comment FS-5
Long-Term Strategy for Hells Canyon Wilderness Area: DEQ should identify a more complete long-term strategy for each Oregon Class I area or monitoring site, including Hells Canyon. The identification of prescribed burning on Forest Service lands in Idaho as the LTS to reduce haze impacts at the HECA monitor seems unsupported by the documentation in the SIP

and therefore, unjustified. For example, the largest speciation of pollutants contributing to regional haze on the MID at the HECA site is ammonium nitrate and the Weighted Emissions Potential analysis for NO_x for HECA shows on-road and off-road mobile sources as the largest source. DEQ should explain why ammonium nitrate decreased dramatically (2000 – 2008) and then increased after 2008, and then discuss specific strategies to reduce the largest contributing pollutant to haze at HECA.

Another example: Organic mass is the second largest contributor to haze on the Most Impaired Days at HECA. WEP and source-apportionment modeling suggests that area non-point sources, such as agricultural sources, residential wood combustion, and fugitive dust, are the largest contributors to primary organic aerosols. Figures illustrating extinction-weighted residence times are insufficient evidence that prescribed fire on Forest Service lands in Idaho are the cause of haze at HECA on 20% MID. DEQ should clarify why other low-level area sources with relatively high weighted residence times are not addressed in the LTS for HECA and why only the Forest Service is mentioned rather than all prescribed burning, including agricultural burning.

DEQ Response FS-5
In Table 4.1, DEQ provides a summary of the top haze forming pollutants and sources at each Class I Area or IMPROVE site and how certain elements of the LTS would be particularly applicable at those locations. DEQ removed the figures and text related to the WEP analysis of HECA visibility impairment.

6.3.4.2 National Park Service

6.3.4.2.1 <u>General Comments</u>

Comment NPS-1
Four factor analyses: We find that Oregon DEQ's process directly follows the requirements of the Clean Air Act (CAA). We fully support Oregon DEQ's process for evaluating potential controls for further reasonable progress, which only applied the four statutory factors identified in the Clean Air Act. In contrast to many other states, Oregon DEQ did not introduce factors that are not in the CAA reasonable progress provisions (i.e., the visibility benefit of individual reasonable progress control determinations).

DEQ Response NPS-1
DEQ did not make changes to the Regional Haze SIP in response to this comment.

Comment NPS-2
Energy and non-air factor, co-benefits, environmental justice: We applaud DEQ's analysis of co-benefits from potential reasonable progress controls as this demonstrates environmental leadership in the region. Evaluating the co-benefits of reductions to further environmental justice is vitally important for promoting thriving communities in underserved areas as well as our national parks. We suggest that DEQ also consider the co-benefits of reducing nitrogen and sulfur deposition in nearby national parks in their analyses. Pollutant deposition can lead to acidification, eutrophication, and/or exceedance of critical loads for sensitive ecosystems in national parks and beyond. Reducing haze causing emissions will also reduce nitrogen and sulfur deposition across the region.

DEQ Response NPS-2
DEQ appreciates this recommendation and will include an assessment of environmental co-benefits in the final SIP.

Comment NPS-3
Q/d screening: We support DEQ's source screening methodology. The DEQ screening process was sufficiently inclusive to select a reasonable number of sources for consideration in the four-factor analyses. The use of Plant Site Emission Limits and the goal of capturing 80% of the total Q (NO_x + SO_2 + PM10 in TPY) represents a robust source selection process. We note that at least four states are using lower Q/d values than DEQ and at least two other states are also using Q/d =5, highlighting that Oregon DEQ's source selection process was reasonable and consistent with other state processes. Of the 32 facilities initially selected using Q/d, 23 were required to submit four-factor analyses FFAs and 17 of these undertook a detailed analysis.

DEQ Response NPS-3
DEQ did not make changes to the Regional Haze SIP in response to this comment.

Comment NPS-4
Cost threshold: We support DEQ's use of a $10,000/ton cost threshold for determining whether controls are reasonable. For example, we understand that Colorado is also using a $10,000/ton cost-effectiveness threshold. We agree that the 3-step "binned" process followed by DEQ to evaluate sources is a logical approach to determining where cost-effective reductions may be achieved. The $10,000/ton cost-effectiveness threshold is higher than the threshold DEQ used in the first round of RH planning. We find it logical that cost thresholds will need to increase in subsequent planning periods as considering smaller sources and more costly controls becomes necessary for further reasonable progress. Additionally, Oregon is home to 12 Class I areas that DEQ needs to address, far more than many other states. Each of these considerations suggests that it is appropriate for DEQ to set a slightly higher cost threshold relative to previous planning periods and relative to other states. We also note that many of the controls considered are well below DEQ's cost-effectiveness threshold. These controls may be less expensive (and more cost-effective) once the errors in the cost analyses are revised.

DEQ Response NPS-4
DEQ did not make changes to the Regional Haze SIP in response to this comment.

Comment NPS-5
PSEL reductions below Q/d threshold: We appreciate this as an anti-backsliding effort by Oregon DEQ. Bringing the PSEL more in-line with actual emissions from recent years is a positive step to prevent emission increases in the future. We recommend that DEQ include a SIP requirement for the 17 facilities that accepted PSEL reductions. The SIP should require a FFA analysis if these facilities propose increasing PSELs under a subsequent permitting action in this planning period that would cause the facility to exceed the initial Q/d screening criteria. Without this provision, facilities going through a permitting action may be allowed to focus only on the affected units and not required to take a facility-wide look at control options. This could, in effect, allow the source to piecemeal control technology determinations and restrict FLM opportunities for engagement in such decisions.

DEQ Response NPS-5
DEQ allowed seven facilities to forgo FFAs because the facilities agreed to PSEL reductions or demonstrated they had lowered PSELs in a recent permit renewal. DEQ made those PSEL

reductions enforceable through stipulated agreements and orders or permit modifications. SAFOs include the following statements:

- The PSEL and unassigned emissions reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.
- PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

DEQ includes SAFOs and modified permits documenting PSEL reductions in Appendix E, as follows:

- Kingsford Manufacturing Co: modified permit
- Klamath Energy LLC: modified permit
- Roseburg Forest Products – Medford: June 2017 permit renewal
- Roseburg Forest Products – Riddle: July 2019 permit renewal
- Timber Products: May 2020 permit renewal
- Cascade Tissue Group: SAFO
- PGE - Beaver: SAFO

While DEQ did not choose to include in the SIP an explicit, potential FFA requirement for these facilities, DEQ did add the following statement to Section 3.7.3: For facilities choosing to comply with Regional Haze Round 2 through PSEL reduction, DEQ may reopen any issued permit to include applicable requirements consistent with Oregon Regional Haze regulations and sources may be subject to reexamination of visibility impacts if new information warrants reassessment.

Comment NPS-6

Cost calculations, interest rate, equipment life: We agree with decision to adjust the interest rate and equipment life assumptions (which affects the capital recover factors) in the cost analyses provided by sources/consultants. This is consistent with the EPA Control Cost Manual and recommendations that the NPS has provided to states/sources across the country. Please provide the full cost analyses/determinations made by DEQ.

We find that many consultants are applying other analysis assumptions/methods that tend to artificially inflate the costs of control (e.g., operating costs and retrofit factors). In our analyses we attempted to correct these errors. We recommend Oregon DEQ identify and address these issues where possible in order to develop accurate cost analyses. In most cases, correcting these errors will reduce the cost of control.

DEQ Response NPS-6

DEQ provided NPS agency files and documents related to DEQ's full cost analyses and pollution control determinations for each facility on July 23, 2021. DEQ sent NPS all SAFOs for comment on August 16, 2021.

Comment NPS-7

Weight of evidence approach: We applaud DEQ's use of a weight-of-evidence approach when evaluating reasonable controls. DEQ's approach was used to verify that the appropriate sources were included in the RP determinations, rather than using it to remove potential candidate sources from the list. As noted previously, this is in line with the CAA requirements to evaluate sources according the four statutory factors and does not introduce an unintended "fifth factor" into the individual source determinations.

DEQ's weight-of-evidence analysis assessed the overall state-wide benefits of potential controls and considered additional metrics beyond the initial Q/d screening analysis. In addition to Q/d, DEQ considered Extinction Weighted Residence Times, Weighted Emission Potential, an environmental justice score and the facility impact on vulnerable populations. We agree that WEP and EWRTs are a more sophisticated surrogate for the potential visibility impact of facility as these approaches also account for meteorology and visibility monitoring information.

We conclude Oregon's thresholds for selecting sources were sufficiently robust to capture a reasonable subset of sources. The weight-of-evidence ranking approach applied reasonable comparisons of the potential importance or weight of control to focus on the facilities where reductions would achieve the greatest improvement. We find that Oregon applied this information in a reasonable way to derive a reasonable set of potential control options under the RHR.

DEQ Response NPS-7
DEQ did not make changes to the Regional Haze SIP in response to this comment.

Comment NPS-8
Glidepath adjustment: We support Oregon's decision to opt out of adjusting the glidepath for international contributions. As we have shared with other states, when made, glidepath adjustments for international emissions cannot be treated as static. Modeling the future influence of international emissions in 2028 is challenging and extrapolating that to 2064 is even more so, especially given dynamics in international economies and global commitments to address climate change. Regional haze glidepath adjustments for international emissions are based on the best modeling information available and will need to be revisited in future planning periods as new information about international emissions becomes available. By choosing not to apply an interim international adjustment to the regional haze glideslopes for its Class I areas, Oregon is keeping the regional haze target fixed and making more substantive strides to reduce haze causing emissions in this planning period. This approach focuses efforts on the feasible and reasonable options that Oregon can implement within this planning period, while maintaining perspective on the overall goal of the RHR. We appreciate this position as it fulfills the spirit and intent of the RH provisions in the CAA.

DEQ Response NPS-7
DEQ did not make changes to the Regional Haze SIP in response to this comment.

6.4.3.2.2 <u>Facility-specific Comments</u>

DEQ includes NPS facility-specific comment letters in Appendix G. In Table 6.2, DEQ lists the key elements of each facility-specific comment letter and DEQ's corresponding responses.

Table 6-2: National Park Service facility specific comments

Facility ID	Facility	NPS Comment	DEQ Response
31-0006	Boise Cascade Wood Products, LLC - Elgin Complex	<u>Concerns with All4 analyses</u> Assumed retrofit factor of 1.5 for every woodwaste boiler it evaluated in Oregon, while EPA CCM recommends site-specific retrofit factors greater than the 1.0 default value should be based on thorough and well-documented analysis of the individual factors involved in a project.	DEQ adjusted cost estimates for consistency among emissions units, including adjustment to current prime rate (3.25%), 30

		All4 assumed a 20-year life for boilers, while for all other OR and WA woodwaste-fired boilers All4 evaluated, assumed 25-year life. All4 used a 2019 Chemical Engineering Plant Cost Index = 603.1; the correct CEPCI = 607.5. All4 used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM. All4 overestimated the operating costs of SCR (and SNCR) with substituted values for “Total operating time for the SCR (t_{op})” and “Total NOx removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. NPS provides explanation of correct use of “Design Parameters” and “Data Input” spreadsheets. All4 included property taxes in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment. NPS cites finding in New Hampshire draft Regional Haze SIP re: technical feasibility of SCR on wood-fired boilers. At Burgess BioPower, the NOx limit in the permit is 0.060 lbs NOx/MMBtu on a 30-day rolling average, based on the use of SCR technology. <u>Conclusions</u> Addition of SCR to Power Boilers #1 & #2 would reduce NOX emissions by 153 ton/yr and be much less expensive than estimated by All4 and its cost-effectiveness is well below the Oregon threshold.	year lifetime, and emissions at PSEL. DEQ removed sales tax costs from FFA analysis as Oregon has no sales tax. DEQ acknowledges additional corrections that NPS recommends, such as retrofit factor, CEPCI, operating costs, reagent costs and property tax; however DEQ generally did not correct for such factors if DEQ had already concurred on the technical infeasibility of certain controls or was working with facilities to pursue alternative methods of emission reductions.
15-0004	Boise Cascade Wood Products, LLC - Medford	Same comments and concerns, with facility-specific examples, as Boise Cascade – Elgin. <u>Conclusions</u> Addition of SCR to Power Boilers #1, & #3 #2 would reduce NOX emissions by 189 ton/yr and be much less expensive that estimated by All4 and its cost-effectiveness is well below the Oregon threshold.	Please see DEQ Response to Boise Cascade – Elgin.

21-0005	Georgia-Pacific – Toledo LLC	<u>SCR at Power Boiler and Package Boiler</u> GP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the Power Boiler and the Package Boiler. All4 overestimated capital costs: a retrofit factor of 1.5 without justification and documentation required by EPA Cost Control Manual and policy. All4 overestimated operating costs of SCR with substituted values for “Total operating time for the SCR (top)” and “Total NOx removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. All4 used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM. All4 overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of cost derivation. Instead of All4’s estimated cost-effectiveness = $13,579/ton, we estimate a Total Annual Cost of $1.2 million = $12,446/ton for addition of SCR to remove 97 ton/yr of NOX. The cost effectiveness of adding SCR for Power Boiler #3 also exceeds the OR DEQ threshold under actual conditions, but that result is highly dependent upon the cost of reheating the SCR inlet gas stream and should be verified. The same issues apply to Power Boiler #1 and the Hogged Fuel Boiler #4. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for Power Boiler #1 and the Hogged Fuel Boiler #4. <u>SNCR at Power Boiler #3</u> All4 overestimated costs: Interest rate too high - 4.75% versus 3.25%.	Please see DEQ Response to Boise Cascade – Elgin.

		$5.00/mmBtu fuel cost not justified - versus approximately $4.00/mmBtu current industrial cost of natural gas in Oregon according to the EIA. Operating costs overestimated because All4 overrode/overestimated the “Total operating time for the SNCR” parameter (8531 hrs versus 5902 hrs). <u>Conclusions</u> Addition of SCR to Power Boilers #1 and Hogged Fuel Boiler #4 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL or actual operating conditions. Addition of SCR to Power Boiler #3 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness relative to the OR DEQ threshold under PSEL and actual operating conditions is highly dependent upon costs to reheat the SCR inlet gas stream; this should be investigated further. Addition of SCR to these three boilers could reduce NOX emissions by 494 tons/yr under PSEL conditions or 393 tons/yr under actual conditions. Addition of SNCR to Power Boiler #3 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL or actual operating conditions.	
04-0004	Georgia Pacific - Wauna Mill	<u>SCR at Power Boiler and Fluidized Bed Boiler</u> GP and its consultant (All4) overestimated capital and operating costs of applying SCR to the Power Boiler and the Fluidized Bed Boiler. *See comments to GP Toledo*. Instead of All4’s estimated cost-effectiveness = $15,069/ton, we estimate a Total Annual Cost of $1.8 million = $8775/ton for addition of SCR to remove 202 ton/yr of NOX. <u>Conclusions</u> Addition of SCR to the Power Boiler and the Fluidized Bed Boiler is much less expensive than estimated by Georgia-Pacific and its	Please see DEQ Response to Boise Cascade – Elgin.

		cost-effectiveness would not exceed the OR DEQ threshold under PSEL or actual operating conditions. Addition of SCR to these two boilers could reduce NOX emissions by 732 tons/yr under PSEL conditions or 395 tons/yr under actual conditions.	
22-3501	Cascade Pacific Pulp, LLC - Halsey Pulp Mill	CPP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the power boilers, PB#1 and #2. The maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy. Overestimated operating costs of SCR with substituted values for “Total operating time for the SCR (t_{op})” and “Total NOx removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. Used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM. Overestimated reagent costs by more than an order of magnitude with no justification. Included costs for reheating the SCR inlet gas stream with no explanation of cost derivation. Instead of All4’s estimated cost-effectiveness = $16,029/ton at PB#1; we estimate a Total Annual Cost of $0.75 million = $6253/ton for addition of SCR to remove 121 ton/yr of NOX. We applied the SCR CCM workbook to PB#1 & #2 for both the PSEL and actual conditions; the cost-effectiveness of adding SCR falls below the OR DEQ threshold of $10,000/ton under PSEL conditions. <u>Conclusions</u> The cost-effectiveness of adding SCR falls below the OR DEQ threshold of $10,000/ton for the PSEL cases for both boilers. Addition of SCR to PB#1 under actual conditions is slightly above the OR DEQ threshold and the costs of reheating the	Please see DEQ Response to Boise Cascade – Elgin.

		SCR inlet gas stream should be further investigated. The cost effectiveness of adding SCR for PB#2 clearly exceeds the OR DEQ threshold under actual conditions. Addition of SCR to these two boilers could reduce NOX emissions by 189 tons/yr under PSEL conditions or 53 tons/yr under actual conditions.	
208850	International Paper - Springfield	IP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the Power Boiler and the Package Boiler. All4 overestimated capital costs when it assumed a retrofit factor of 1.5 without the justification and documentation required by EPA Cost Control Manual and policy. Overestimated operating costs of SCR with substituted values for “Total operating time for the SCR (t_{op})” and “Total NOx removed per year” for values calculated by the CCM “Design Parameters” spreadsheets. Used a 4.75% interest rate instead of current bank prime rate = 3.25% as recommended by the CCM. Overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of cost derivation. Instead of All4’s estimated cost-effectiveness = $4606/ton; we estimate a Total Annual Cost of $1.6 million = $2010/ton for addition of SCR to remove 786 ton/yr of NOX. <u>Conclusions</u> Addition of SCR to the Power Boiler and Package Boiler is much less expensive than estimated by IP and cost-effectiveness would not exceed the OR DEQ threshold under PSEL operating conditions or the Power Boiler under actual conditions. Addition of SCR to the Package Boiler would exceed the OR DEQ threshold under actual operating conditions.	DEQ adjusted cost estimates for consistency among emissions units, including adjustment to current prime rate (3.25%), 30 year lifetime, and emissions at PSEL. DEQ acknowledges additional corrections that NPS recommends, such as retrofit factor, CEPCI, operating costs, reagent costs and property tax; however DEQ generally did not correct for such factors if DEQ had already concurred on the technical infeasibility of certain controls or was working with facilities to pursue alternative methods of emission reductions. Unique among the emissions units DEQ reviewed in this round of regional haze, the package boiler is used very little, at about 0.5% of its potential to emit. DEQ determined that restrictions on backup fuel types and PSEL reductions would have greater impact than requiring a control device on the package boiler individually.

		Addition of SCR to the Power Boiler could reduce NOX emissions by 786 tons/yr under PSEL conditions or 127 tons/yr under actual conditions.	For the power boiler, DEQ found SCR cost-effective. DEQ deemed equivalent emission reduction could be achieved through PSEL reduction across all emission units and continuous emission monitoring on the power boiler to monitor compliance with an emission rate of 0.25 lb NOx/MMBtu on a 7-day rolling average.
09-0084	Gas Transmission Northwest LLC - Compressor Station 12	The company did not use the most recent 7th edition of the EPA's Cost Control Manual. The company assumed a 75% control efficiency. This seems low for SCR. Our analysis assumed 90% control. Based on review of most recent CAM database, we concluded that 90% NOx control by SCR is achievable in practice and reasonable to assume in the cost analysis. Company assumed 3% sales tax and property taxes. Does OR charge sales and property taxes for pollution control projects and equipment? The revised 7th edition of the CCM does not include sales tax in the cost analysis. The company assumed a cost of $2,765,000 to $3,712,500 for combustion controls in addition to SCR on the CTs. Are both controls needed to achieve 75% NOx reduction? What is the basis for this? The company assumed $105,326 to $143,628 in administrative charges for each CT. This seems high. When using the revised 7th Edition CCM, the estimated administrative charges are roughly $3000/year in 2019 dollars. The company used a 5% interest rate and a 20-year equipment life. The current bank prime rate (3.25%) and 30-year equipment life should be assumed. Using PSEL assumptions, the costs to add SCR to turbines 12-A and 12-B are	DEQ requested that GTN justify its assumption of 75% control efficiency and DEQ used 90% SCR control efficiency in DEQ's review of the FFAs. DEQ removed sales tax costs from FFA analysis as Oregon has no sales tax. DEQ did not make changes to the administrative costs or property tax costs the facility submitted. DEQ did not make changes to the cost of combustion controls in addition to SCR; the facility's explanation for combustion controls was, "tempering air needed to ensure exhaust temperature <900F." DEQ adjusted all cost estimates for consistency among emissions units, including adjustment to current prime rate (3.25%), 30-

		significantly lower than DEQ's $10,000/ton threshold at $1,833/ton of NOx removed for unit 12-A and $3,801/ton of NOx removed for unit 12-B. When using reduced operating scenarios (based on reduced fuel use assumptions), the cost of installing SCR is still below DEQ's cost threshold, down to 16% of full capacity for unit 12-A and 34% of full capacity for unit 12-B, suggesting that SCR is likely still cost effective under reduced operating scenarios. We concur with DEQ's determination documented in a January 21, 2021 letter to the company, that SCR is likely cost effective at units 12-A and 12-B. However, we recommend that DEQ correct some of the additional errors identified in the cost analysis (other than interest rate and equipment life), as this results in SCR being a much more cost effective option than estimated by DEQ or the company.	year lifetime, and emissions at PSEL.
18-0096	Gas Transmission Northwest LLC - Compressor Station 13	Same as comments to Compressor Station 12. Using PSEL assumptions, the costs to add SCR to turbines 13-C and 13-D are significantly lower than DEQ's $10,000/ton threshold at $4,074/ton of NOx removed for unit 13-C and $3,887/ton of NOx removed for unit 13-D. When using reduced operating scenarios (based on reduced fuel use assumptions), the cost of installing SCR is still below DEQ's cost threshold, down to 37% of full capacity for unit 13-C and 35% of full capacity for unit 13-D, suggesting that SCR is likely still cost effective under reduced operating scenarios. We concur with DEQ's determination, documented in a January 21, 2021 letter to the company, that SCR is likely cost effective for units 13-C and 13-D. However, we recommend that DEQ correct some of the additional errors identified in the cost analysis (other than interest rate and equipment life), as this results in SCR being a much more cost effective option than estimated by DEQ or the company.	Please see DEQ response to GTN Compressor station 12.
15-0159	Biomass One, L.P.	<u>April 2021 Comments</u> BiomassOne used an interest rate of 4.75% instead of the current prime rate of 3.25%	DEQ adjusted all cost estimates for consistency among

		and assumed a 20-year lifetime rather than 30 years as recommended in the EPA control cost manual. Using the company's calculation methods with an interest rate of 3.25% and useful life of 30 years brings the cost per ton to about $7,000. <u>June 2021 Comments</u> NPS agrees that that SCR is cost effective for the two boilers at BioMass One. Using EPA's most recent cost estimation worksheet (7th edition of the Control Cost Manual), rather than the company's methods, suggests that SCR is more cost effective than indicated by the company's analysis ($5,000 to $6,900 per ton).	emissions units, including adjustment to current prime rate (3.25%), 30-year lifetime, and emissions at PSEL.
10-0025	Roseburg Forest Products - Dillard	<u>April 2021 Comments</u> The costs for SNCR at the Roseburg FP Dillard facility appear to be reasonable as presented in the four factor analysis. an interest rate of 4.75% was used, rather than the current bank prime rate of 3.25% as recommended by the control cost manual The analysis relied upon an old reference to calculate capital costs (USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR), issued July 15, 2003.The capital costs should be estimated using the methods from the control cost manual. reduction (SNCR), issued July 15, 2003. The analysis dismisses the use of SCR for NOx emissions reduction as technically infeasible because of the potential for wood combustion byproducts to foul or plug the catalyst. However, other facilities powered by wood combustion have successfully employed tail-end SCR (e.g. Bridgewater electrical generating facility in Bridgewater, New Hampshire). Tail-end SCR is technically feasible for the Dillard facility and should be evaluated to determine if it is cost effective. <u>June 2021 Comments</u> NPS agrees that SNCR would be cost effective on all three boilers.	DEQ adjusted all cost estimates for consistency among emissions units, including adjustment to current prime rate (3.25%), 30-year lifetime, and emissions at PSEL. DEQ generally did not correct for such factors as citations of older EPA Cost Control Manuals since DEQ had already concurred on the technical infeasibility of certain controls and the facility was pursuing alternative methods of emission reductions. DEQ acknowledges the information NPS provided in April and June 2021 regarding the technical feasibility and potential emissions reductions of tail-end SCR on biomass boilers, including examples of two facilities in NH employing this technology. DEQ did not evaluate tail-end SCR at RFP Dillard because in late 2020, RFP Dillard

		Did DEQ evaluate tail-end SCR? Other biomass boilers use tail-end SCR. NPS estimates for both SNCR and SCR using the EPA costing worksheets, suggest that SCR may be even more cost effective than SNCR given the greater NOx reduction ($2,800-$3,500 per ton).	had offered PSEL reductions, NO_x emission limits, and continuous monitoring to verify compliance; DEQ continued to evaluate NO_x reduction achievable with these options throughout spring 2021 and ultimately document findings and facility requirements in a stipulated agreement and order issued on August 9, 2021.

6.5 Public Outreach

DEQ held two public information sessions about the Round 2 Regional Haze process on October 22 and December 8, 2020. The first public information session had over 100 participants, and DEQ covered the Regional Haze process up through the four factor screening process. The second public information session had over 60 participants, and reviewed the four factor analysis process.

DEQ provided public notice of the 2018 2018 Regional Haze Plan on August 27, 2021. DEQ held one public hearing on October 27, 2021. DEQ accepted written public comment on the proposed rulemaking until 4 p.m. on Nov. 1, 2021, after granting a 30-day extension from the original end date for public comment.

DEQ provided notice of the proposed rulemaking and rulemaking hearing by:

- On Aug. 27, 2021, filing notice with the Oregon Secretary of State for publication in the September 2021 Oregon Bulletin;
- Notifying the EPA via GovDelivery;
- Posting the Notice, Invitation to Comment and Draft Rules on the web page for this rulemaking, located at: Regional Haze 2021;
- Emailing approximately 22,557 interested parties on the following DEQ lists through GovDelivery:
  - Rulemaking
  - DEQ Public Notices
  - Air Quality Permits
  - Regional Haze
- Emailing the following key legislators required under ORS 183.335:
  - Senate President Peter Courtney
  - Senator Lee Beyer
  - House Speaker Tina Kotek
  - Representative Pam Marsh
- Posting on the DEQ event calendar: DEQ Calendar

6.6 Public Comments and Responses

DEQ received approximately 460 written and oral comments during the public comment period and at the public hearing. Original comments are on file with DEQ and longer, more detailed comments are included in their entirety in Appendix H of this Region Haze Plan. Table 6-3, below lists people and organizations that submitted public comments about the proposed rules by the deadline. The following section presents comment summaries with cross references to the comment number.

Table 6-3: Public commenters to publicly noticed 2018 – 2018 Regional Haze Plan.

List of Commenters				
#	**Name**	**Organization**	**Comment Number**	**Type**
1	Jeff Hunt	EPA Region 10	1 - 5	Written
2	Cindy Orlando	National Park Service	6 - 9	Written
3	Rebecca Canright	self	10	Written
4	Mark Canright	self	10	Written
5	Erica Giesen	Self	11	Written
6	David Darling	American Coatings Assoc.	12	Written
7	Kelly Gates + 151	self	13	Written
8	Caryl Brown +287	self	14	Written
9	Jean Avery	self	15	Written
10	Barbara Beattie	self	16	Written
11	Colin Deverell	National Park Conservation Association	17	Hearing + Written
12	Kristina Becherer	Roseburg Forest Products	18	Written
13	William Enoch	Gas Transmission Northwest	19	Written

List of Commenters				
#	**Name**	**Organization**	**Comment Number**	**Type**
14	Greg Sotir	Cully Air Action Team	20	Written
15	Jamie Pang	Oregon Environmental Council	21	Written
16	Molly Tack-Hooper	Earthjustice	22	Hearing + Written
17	Jenna Knobloch	Oregon Prescribed Fire Council	23	Hearing + Written
18	Kurt Lumpkin	Biomass One	24	Written
19	Alicia Cohen	Woodsmoke Free Portland	25	Hearing
20	Michael Lang	Friends of the Columbia Gorge	26	Hearing
21	Samuel Taylor	Self	27	Written
22	Susie Jenkins	Self	28	Written
23	Betsy Toll	Self	29	Written
24	Kendrick Simila	Self	30	Written
25	Cathryn Chudy	Self	31	Written

Comment #1
To be practicably enforceable, a SIP provision must specify: (1) a technically accurate limitation and the portions of the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits); and (3) the method to determine compliance including appropriate monitoring, recordkeeping and reporting. In [citations], EPA made clear that both the emission limit and the provisions that make the emission limit enforceable as a practical matter must be included in the SIP: “As states consider limits, the rule also requires that additional consideration be given to ensuring that not only the limit, but also the appropriate monitoring, recordkeeping, and reporting provisions needed to make those limits practicably enforceable are included."

DEQ Response
For each instance where EPA commented that a facility agreement lacked a sufficient emission limit, time period or method to determine compliance, DEQ either negotiated an addendum

containing the required information to an existing agreement or included the relevant sections of a facility's Title V permit in the proposed Regional Haze SIP for EPA approval.

Comment #2
Northwest Pipeline LLC, Oregon City Compressor Station – the Stipulated Agreement and Final Order (SAFO) included in Appendix E of the proposed regional haze plan states: “The Permittee shall replace two RICE that comprise EU1 at the Facility with new emissions units to reduce PSELs of round II regional haze pollutants.” However, there is no specified deadline for installation of these units. Instead, the SAFO states, “DEQ and Permittee shall meet no later than July 1, 2026, to discuss the project and determine what permitting Permittee needs for the replacement.” As currently written, this would not be practicably enforceable for inclusion in the SIP.

DEQ Response
DEQ negotiated an agreement addendum that includes a deadline of July 31, 2031 for installation of new emission units.

Comment #3
Cascade Pacific Pulp, LLC Halsey Pulp Mill – the SAFO included in Appendix E states, “Permittee shall design the low NOx burner with an objective of achieving a 33% reduction in NOx emissions from Power Boiler #1 (PBIEU).” While we understand ODEQ and the permittee would need to conduct source testing and analysis to determine a more precise emission limit, the objective as written is not enforceable as a practical matter—the source is not required to operate the low NOx Burner to achieve 33% reduction or a specific emission rate. One possible solution is for ODEQ to include in a revised SAFO an emission limit or specific emission rate derived from operation of the low NOx burners that is enforceable in the interim prior to the longer-term determination of a more precise emission limit thorough source testing.

DEQ Response
DEQ negotiated an agreement addendum that includes an emission limit or specific emission rate.

Comment #4
Several of the SAFOs included in Appendix E contain revised plant site emissions limits (PSELs) to reduce regional haze precursor emissions. However, the SAFOs as currently written do not contain the associated monitoring, recordkeeping, and reporting provisions needed to make those limits practicably enforceable. One possible solution is for ODEQ to include these provisions in revised SAFOs. Another solution is to supplement the existing SAFOs by submitting for approval into the SIP the specific monitoring, recordkeeping, and reporting provisions of the current Title V permits for these facilities.

DEQ Response
For facilities that agreed to reduce PSELs as a means of compliance, DEQ included those sections of permit pertaining to monitoring, record keeping or reporting in the 2018 – 2028 Regional Haze SIP for EPA approval.

Comment #5
Section 3.7.4 discusses six facilities that were evaluated by ODEQ using the regional haze four-factor analysis for which no new controls were found to be cost-effective. The proposed SIP does not include a technical demonstration that the sources' existing measures are not necessary to make reasonable progress and thus do not need to be included in the SIP. Therefore, in the absence of a robust technical demonstration, see Memo at 9-10, these existing measures, either in the form of SAFOs or relevant portions of the current Title V permits, must be included in the SIP consistent with the requirements laid out above.

DEQ Response
DEQ appreciates EPA's citation of section 4.1 of the July 8, 2021, clarification memo (Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period) titled, "Determining When Existing Measures are Necessary for Reasonable Progress."

DEQ does not agree that the 2018 – 2028 Regional Haze SIP (RH SIP) must include the facilities' permits or negotiated agreements to maintain existing controls for those controls to be federally enforceable for the purpose of preventing visibility impairment.

Based on the four factor analyses, DEQ agrees that existing controls at these six facilities must be maintained to prevent future visibility impairment; DEQ has revised section 3.7.4 of the proposed RH SIP to state that requirement explicitly for each of these six facilities. The controls are federally enforceable in facility permits and comply with NESHAPs and Title V.

DEQ agrees that preventing visibility impairment depends on these facilities not increasing emission rates. For each facility, DEQ has included in section 3.7.4 of the proposed RH SIP the enforceable emission limit or other enforceable requirement that demonstrates that the sources must maintain existing controls. The emission limits are set based on actual emissions. Section 4.1 of the EPA July 8, 2021 clarification memo allows, "States should also clearly identify the instrument in which the relevant limit(s) exist (by providing, e.g., the applicable permit number and where it can be found) and provide information on the specific permit provision(s) on which they are relying." For each of the six facilities, DEQ has included in section 3.7.4 of the proposed RH SIP, the relevant permit number, where that permit can be found, and the specific permit provisions on which DEQ is relying.

Comment #6
Significant opportunities for emission reductions are available that could further improve the draft SIP. Specifically, we recommend Oregon require the most significant pollution reductions found to be technically feasible and cost-effective for facilities reviewed.

The draft SIP would be strengthened by including a thorough technical justification for compliance strategies that achieve fewer emission reductions than originally proposed. See Enclosure 1 for detailed technical comments. We have also included Enclosure 2, a zipped file of calculation worksheets supporting NPS cost-effectiveness analyses.

We recommend that control determinations be based on the results of four-factor analysis, rather than adjustments that allow facilities to retroactively avoid selection.

We encourage Oregon to fully document its rationale for control decisions and to take every opportunity to reduce haze-causing emissions. The cumulative benefits of emission reductions from many sources are necessary to achieve the Clean Air Act and Regional Haze Rule goal to “prevent future and remedy existing visibility impairment” in Class I areas. Oregon analyses have identified additional emission reductions that would make further progress toward this goal. Oregon has an opportunity to improve the effectiveness of their Regional Haze SIP by choosing to require these cost-effective emission controls identified using the four statutory factors. These incremental steps will contribute towards aligning Crater Lake National Park and other NPS Class I areas in the region with reasonable progress goals.

DEQ Response
DEQ appreciates NPS recommendations and shares the goal to reduce haze-forming emissions as much as possible. For the Round 2 implementation period, DEQ achieved agreements with 16 facilities to continue to make reasonable progress towards natural visibility conditions by 2064. In total, these agreements assure plant site emission limit reductions of 11,000 tons/year; continuous emission monitoring at 6 facilities, pollution control device installation at 6 or more facilities, and emission unit replacement at one or more facilities.

DEQ carried out the agency's Round 2 Regional Haze Rule responsibilities that pertain to stationary sources under the authority of Oregon Administrative Rules Chapter 340 Division 223. Division 223 rules establish the Round 2 screening process that determines which facilities are subject to analysis of pollution controls based on the four factors (cost, time to install, remaining useful life, non-air and energy impacts). DEQ followed EPA guidance and consulted with other states before establishing the screening threshold of Q/d = 5.00, which captures 80% of Oregon facilities' haze-forming emissions.

Division 223 rules require that screened-in facilities undergo four factor analysis and that DEQ may request additional information and analysis until DEQ deems the information sufficient, adequate and accurate. For Round 2, DEQ required that 23 facilities undergo four factor analysis. DEQ reviewed and adjusted for consistency the four factor analyses, resulting in 17 facilities at which DEQ deemed pollution controls cost-effective at less than $10,000/ton. DEQ communicated the agency's determination to facilities in January 2021. After the January 2021 communication, two of those facilities agreed to lower plant site emission limits such that Q/d < 5.00 and consistent with the Round 2 regional haze screening threshold, were no longer subject to pollution control requirements.

PSEL reduction is one of the compliance options provided in Division 223 if DEQ determines that round 2 regional haze pollutant reduction is cost-effective, based on the four factors. For facilities where DEQ agreed that monitoring, equipment replacement, PSEL reduction or operational changes could achieve emission reductions consistent with reasonable progress, DEQ did not require control installation identified in January 2021 communications to facilities.

DEQ agreed in some cases that controls deemed cost effective in the January 2021 letters to sources were not technically feasible or that equivalent emissions could be achieved through other means (e.g. more efficient operations, furnace shut down) or that controls would be installed by a time certain if a source found they could not achieve agreed-upon emission reductions by other means.

Facilities have agreed to either an emission rate or percent reduction. Emission reductions are verifiable and enforceable through facilities' Title V permits, the stipulated agreements and orders, and by incorporation into the proposed RH SIP.

Comment #8
On page 100 of the draft SIP, regarding responses to NPS comments, the NPS is quoted as saying:
"The analysis relied upon an old reference to calculate capital costs (USEPA Air Pollution Control Technology Fact Sheet (EPA- 452/F-03-031) for selective non-catalytic The capital costs should be estimated using the methods from the control cost manual. reduction (selective non-catalytic reduction, or SNCR), issued July 15, 2003."

The NPS comment, in fact, read:

"The analysis relied upon an old reference to calculate capital costs (USEPA Air Pollution Control Technology Fact Sheet (EPA- 452/F-03-031) for selective non-catalytic reduction (SNCR), issued July 15, 2003. The capital costs should be estimated using the methods from the control cost manual."

DEQ Response
DEQ regrets the error and has made the correction.

Comment #8
- **Boise Cascade Wood Products, LLC - Elgin Complex**
- **Georgia Pacific - Wauna Mill**
- **Cascade Pacific Pulp, LLC - Halsey Pulp Mill**
- **Boise Cascade Wood Products, LLC - Medford**
- **International Paper - Springfield**
- **Georgia-Pacific – Toledo LLC**

The four-factor analyses for the facilities highlighted in bold type share many similarities identified in feedback from NPS to ODEQ; these facilities are further discussed below.

We note that ODEQ may have overlooked a response to our comments on IP-Springfield on page 97 of the draft SIP.

ODEQ conclusions about the NPS's recommendations for additional NOx controls (selective catalytic reduction, or SCR) should be explained in greater detail, this would strengthen the draft SIP.

ODEQ has applied one set of circumstances to all of the boilers at these facilities. The only facilities with woodwaste-fired boilers are the two Boise Cascade veneer mills and the fluidized bed boiler at GP's Wauna mill. It is likely that addition of SCR to these boilers would require location downstream of the particulate controls and a method to reheat the gas stream. The other eight power boilers at these facilities are all fired with natural gas and there is no technical concern regarding direct addition of SCR.

If ODEQ identifies "alternative methods of emission reductions," these methods should be at least as effective at reducing NOx emissions as the cost-effective applications of SCR. We recommend that ODEQ fully document how the alternatives contained in the draft SIP meet this test.

In summary, we shared with ODEQ the following early engagement feedback regarding four factor analyses of wood product facilities:

- In ODEQ's review of the power boilers at Georgia Pacific's (GP's) Toledo mill, ODEQ changed GP's 1.5 retrofit factor "to 1 because there is no vendor data" consistent with EPA's Control Cost Manual (CCM) spreadsheet which advises "You must document why a retrofit factor of (>1.0) is appropriate for the proposed project."
- We generally agree with ODEQ's decision for GP-Toledo. Acceptance of the 1.5 retrofit factor should also be justified for the other facilities with documentation of cost-effectiveness analysis. Application of an un-documented retrofit factor significantly inflates the capital cost of SCR.
- A 20-year life for the Boise Cascade boilers was assumed, in contrast a 25-year life was assumed for all other OR and WA woodwaste-fired boilers. This difference should be explained.
- For the Boise Cascade boilers, a 2019 Chemical Engineering Plant Cost Index (CEPCI) = 603.1 was used; the correct CEPCI = 607.5.
- A 4.75% interest rate was applied instead of the current bank prime rate of 3.25% as recommended by the CCM.
- The operating times calculated by the CCM spreadsheets were over-ridden by the paper mills and higher values were substituted. This resulted in significant overestimation of operating costs that are based upon hours of operation.
- The reagent (ammonia) cost/gallon used by the paper mills in their SCR spreadsheets is an order of magnitude greater than the default value contained in the CCM SCR spreadsheet. The higher reagent cost should be documented or revised to be consistent with the CCM default cost/gallon.
- The paper mills included costs for reheating the boiler outlet gas streams to facilitate application of SCR. While reheat may be necessary if the SCR is applied downstream of emission control devices that reduce the temperature of the gas stream, it would not be necessary for SCR applied to the natural gas-fired power boilers common to these mills. Where reheat is appropriate, e.g., for a biomass-fired boiler with particulate controls, the amount of natural gas needed to reheat the gas stream should be explained and justified. It is our understanding that the only biomass-fired boilers were the Fluidized Bed Boiler at GP-Wauna and the boilers at the Boise Cascade facilities. Analyses would benefit from an explanation of the reheat costs.
- Property taxes were included in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

We appreciate the work ODEQ has done to improve the four factor analyses for individual facilities. A more rigorous demonstration of SCRs technical infeasibility would substantiate the decision to move away from requiring this control technology where that was done. Barring such a demonstration, we recommend the application of SCR to reduce NOx emissions should be required.

DEQ Response
DEQ regrets the oversight. DEQ has included a response to NPS comments on IP Springfield on page 97 of the SIP.

As in the early engagement and consultation, DEQ appreciates the corrections that NPS recommended that DEQ make to the four factor analyses for the wood products facilities. As DEQ responded in the originally publicly noticed RH SIP, DEQ did not make those corrections if DEQ and the facilities were no longer considering SCR or SNCR as a means to reduce emissions. DEQ used the four factors to identify sources at which DEQ deemed it cost-effective for the facility to reduce Round 2 regional haze pollutants, using a threshold of $10,000/ton.

DEQ adjusted several factors for consistency and in several cases, required facilities to submit more precise information, such as vendor quotes, to justify their cost-effectiveness calculations. Once DEQ deemed the information sufficient to assess cost effectiveness relative to the threshold, DEQ did not require or perform a more detailed financial analysis or additional corrections to attain greater precision or certainty beyond that required by the regional haze rule.

However, DEQ agrees that in cases where DEQ agreed that SCR or SNCR was not technically feasible, that DEQ should have provided a more detailed explanation for that conclusion. DEQ has included additional explanations in section 3.7 of the proposed RH SIP for facilities where DEQ agreed SCR or SNCR were not technically feasible, as well as additional explanations for DEQ's agreements to alternative compliance.

Comment #9
NPS feedback attachment to letter: facility specific feedback.

DEQ Response
Because of the detail contained in the NPS 10/29 letter and additional feedback, DEQ includes NPS 10/29 comment letter and feedback in Appendix G of this Regional Haze Plan. The response to comment 8 is also DEQ's response to the facility-specific comments.

Comment #10
The draft rule does not address the need for emission controls for all major sources contributing to haze in the National Scenic Area, including one of the largest Concentrated Animal Feeding Operations (CAFO) in the country located in Boardman, Oregon. This CAFO is responsible for emitting large amounts of ammonium nitrate. The DEQ has determined that “over 50% of visibility impairment in the Columbia River Gorge can be attributed to ammonium nitrate.” This CAFO should be included in the list of facilities required to develop pollution control plans for round 2 of the Regional Haze Program.

DEQ Response
DEQ received a similar comment during the June 2021 public comment period held for revision to the Division 223, state Regional Haze Rules which establish provisions for stationary sources that contribute to visibility impairment from NOx, SO_2 and PM10. DEQ does regulate the facility the commenters refer to through a Title V permit for electric power generation from biogas combustion, but the combined permitted Round 2 regional haze pollutants from that facility total 92 tons/year. Based on those total emissions and the distance to the nearest Class I wilderness areas (Mount Hood, ~140 km; Eagle Cap, ~160 km, Hells Canyon, ~241 km), the Q/d ratio would be less than 5 and the Division 223 rules would not require the facility to conduct four factor analysis, reduce emissions or install controls. The air emissions from the agricultural operations at the facility are not covered under the source’s stationary source permit, as the EQC is prohibited from regulating most emissions from agricultural operations.

DEQ agrees with commenters that area emissions from agricultural operations contribute to regional haze in the Columbia River Gorge National Scenic Area and Class 1 areas in Oregon. DEQ has included strategies to reduce haze-forming emissions from agricultural sources in the proposed RH SIP Long-term Strategy (Section 4 of the proposed RH SIP). One strategy is to work with the OR Dept. of Agriculture to implement recommendations from the 2018 Dairy Air Quality Task Force. DEQ has twice sought funding from the Oregon Legislature to begin implementing those recommendations but was denied both times.

Comment #11
I'm writing in strong support of the proposed revised Regional Haze rulemaking. Down in southern Oregon we have had what we are all calling a '5th' season of smoke down here for close to the 5th year in a row due to climate change-fueled wildfires and we do not need any airborne industrial pollutants to further degrade our air quality.

I urge you to adopt the proposed revised Regional Haze rules and to vigorously enforce them to protect Oregon's natural resources as much as possible.

DEQ Response
DEQ considered this comment and thanks the commenter.

Comment #12
I noticed that DEQ mentioned a possible architectural and industrial maintenance (AIM) in the future – could I please request DEQ consider the Ozone Transport Commission (OTC) Phase I rulemaking as a first step since this is reasonable as opposed to adopting a more stringent rule.

DEQ Response
DEQ considered this comment and thanks the commenter.

Comment #13
Today, air pollution remains one of the most serious threats facing national parks, threatening the health of park visitors, wildlife, watersheds and Oregon communities. Despite the great strides that have been made to-date, I am concerned Oregon DEQ has proposed a regional haze plan that does not do enough to actually reduce and control facility emissions that degrade Crater Lake views and harms Oregon communities, especially the communities disproportionately affected by cumulative environmental exposures such as air pollution.

While I greatly appreciate Oregon DEQ’s excellent initial job of considering environmental justice concerns in this plan, I'm reaching out today to call on Oregon DEQ to fulfill its Regional Haze obligations under the Clean Air Act and ensure those communities and our protected public lands actually get the benefit of cleaner air. Please revise the regional haze plan to ensure installation of pollution controls at 17 facilities to achieve meaningful emissions reductions during this planning period. The sooner the clean-up starts, the sooner the benefits!

DEQ Response
For the Round 2 implementation period, DEQ achieved agreements with 16 facilities to continue to make reasonable progress towards natural visibility by 2064. In total, these agreements assure plant site emission limit reductions of 11,000 tons/year; continuous emission monitoring at 6 facilities, pollution control device installation at 6 or more facilities, and emission unit replacement at one or more facilities.

DEQ carried out the agency's Round 2 Regional Haze Rule responsibilities that pertain to stationary sources under the authority of Oregon Administrative Rules Chapter 340 Division 223. Division 223 rules establish the Round 2 screening process that determines which facilities are subject to analysis of pollution controls based on the four factors (cost, time to install, remaining useful life, non-air and energy impacts).

Division 223 rules provide compliance options for facilities subject to regional haze regulation. DEQ accepted information from facilities through August 9, 2021, regarding the technical feasibility of installing cost-effective pollution controls and operational changes with the potential to achieve equivalent emission reductions. For facilities where DEQ agreed that monitoring, equipment replacement, PSEL reduction or operational changes could achieve emission reductions consistent with reasonable progress, DEQ did not require control installation identified in January 2021 communications to facilities. In alignment with Division 223 rules and to maintain regulatory consistency, facilities agreeing to make changes such that Q/d < 5.00 were no longer subject to control installation.

DEQ has added information in Section 3.7 of the proposed RH SIP that describes how DEQ deemed alternative compliance to be capable of providing equivalent emission reductions to controls identified in the four factor analysis process.

Comment #14
Oregon's Regional Haze Rule is an incredibly important tool in protecting air quality and visibility in the Columbia River Gorge National Scenic Area, Crater Lake National Park, and wilderness areas throughout the state. The regional haze program also reduces air pollution in Oregon communities and benefits human health by reducing emissions that cause lung and heart disease.

Unfortunately, the Oregon Department of Environmental Quality's (DEQ) Draft Regional Haze Plan fails to meet the requirements of the Clean Air Act and the Regional Haze Rule. I am very concerned that the draft plan does not require pollution reductions from major sources that DEQ identified as contributing to regional haze in Oregon. Instead, the draft plan allows polluters to reduce maximum pollution levels in their permits without having to reduce actual pollution levels through cost-effective controls. The way the plan is drafted, industries could increase pollution above current levels resulting in no reductions of haze-causing pollutants. This could undermine Oregon's entire strategy for reducing haze-causing pollution.

DEQ has also excluded one of the largest Concentrated Animal Feeding Operations (CAFO) in the country from the draft plan. Three Mile Canyon Farms, located in Boardman, Oregon, is responsible for emitting huge amounts of ammonium nitrate. DEQ has determined that "over 50% of visibility impairment in the Columbia River Gorge can be attributed to ammonium nitrate" (Oregon Department of Environmental Quality: Screening Sources for Four Factor Analysis). This CAFO should have been included in the list of facilities required to develop pollution control plans for round 2 of the Regional Haze Program.

Finally, when DEQ proposed exempting major polluters from installing pollution controls, was there any outreach to communities directly affected by these polluters? It appears that the draft plan lets polluters off the hook while surrounding communities and special places like the Columbia River Gorge continue to be subjected to air pollution.

I urge DEQ to require emission controls for all major sources contributing to haze in Oregon's only national park, its wilderness areas, and the Columbia River Gorge National Scenic Area.

DEQ Response
In developing regional haze rules that allow sources to comply by lowering Plant Site Emission Limits, DEQ acknowledges that emissions prevented in the future are different from current emissions reduced in the short-term. Still, in the context of the regional haze program requirements to attain natural visibility in Class 1 areas by 2064, DEQ asserts that long-term planning to prevent emission increases is an appropriate and effective means of reaching natural visibility targets. DEQ followed a conservative approach (Q/d ≥ 5.00, based on PSELs) to capture the sources likely to be the greatest contributors to visibility impairment now and into

the future. DEQ followed that conservative screening procedure with a conservative cost-effectiveness threshold of $10,000/ton, also based on PSEL, to evaluate pollution controls. As opposed to an approach based on actual emissions, this PSEL-based approach brought in more sources required to undergo four factor analyses and resulted in more sources being required to lower their emissions based on DEQ deeming controls cost-effective.

DEQ carried out the agency's Round 2 Regional Haze Rule responsibilities that pertain to stationary sources under the authority of Oregon Administrative Rules Chapter 340 Division 223. Division 223 rules establish the Round 2 screening process that determines which facilities are subject to analysis of pollution controls based on the four factors (cost, time to install, remaining useful life, non-air and energy impacts). PSEL reduction is one of the compliance options provided in Division 223 if DEQ determines that round 2 regional haze pollutant reduction is cost-effective, based on the four factors.

DEQ agreed in some cases that controls deemed cost effective in the January 2021 letters to sources were not technically feasible or that equivalent emissions could be achieved through other means (e.g. more efficient operations, furnace shut down) or that controls would be installed by a time certain if a source found they could not achieve agreed-upon emission reductions by other means. For facilities where DEQ agreed that monitoring, equipment replacement, PSEL reduction or operational changes could achieve emission reductions consistent with reasonable progress, DEQ did not require control installation identified in January 2021 communications to facilities. Still, through the SAFOs, facilities are held to either an emission rate or percent reduction. Emission reductions are verifiable and enforceable through facilities' Title V permits, the stipulated agreements and orders, and by incorporation into the proposed RH SIP.

DEQ does regulate Three Mile Canyon Farms through a Title V permit for electric power generation from biogas combustion, but the combined permitted Round 2 regional haze pollutants from that facility total 92 tons/year. Based on those total emissions and the distance to the nearest Class I wilderness areas (Mount Hood, ~140 km; Eagle Cap, ~160 km, Hells Canyon, ~241 km), the Q/d ratio would be less than 5 and the Division 223 rules would not require the facility to conduct four factor analysis, reduce emissions or install controls. The air emissions from the agricultural operations at the facility are not covered under the source’s stationary source permit, as the EQC is prohibited from regulating most emissions from agricultural operations. DEQ has included strategies to reduce haze-forming emissions from agricultural sources in the proposed RH SIP Long-term Strategy (Section 4 of the RH SIP).

Negotiation of the Stipulated Agreements and Final Orders with facilities did not include direct outreach to communities near the sources. The orders negotiated, however, were part of the publicly noticed 2018 – 2028 Regional Haze Plan. DEQ did renegotiate revised or additions to agreements in response to comments received during the public comment period.

Comment #15
Please protect the air quality in the Columbia River Gorge. This national scenic area must be protected for all to enjoy -- now and in the future.

DEQ Response
DEQ considered this comment and thanks the commenter.

Comment #16
Please stop the smoke emissions from logging and orchards burning their trimmings and slash piles. The fires from large clear cut slash piles and small orchards all contribute carbon to the atmosphere and increase haze in the gorge. It is antiquated thinking to say "we have always done it this way." Protecting the scenic value of the gorge is important. More important, every step we take to reduce carbon emissions will help slow global warming.

There are local alternatives to dispose of the debris to reduce carbon emissions and recapture carbon to the soil. Chipping and composting are better alternatives than burning. Creative minds can solve global warming, taking a strong stand against burning is your charge.

DEQ Response
Three elements of the Regional Haze Long-term Strategy address slash burning and pursuit of alternatives to burning. EPA recently approved updates to Oregon's Smoke Management Plan, which is incorporated into the State Implementation Plan and the means by which DEQ and the OR Dept. of Forestry track occurrences and effects of prescribed burning. DEQ intends to continue to rely on the Smoke Management Plan to minimize visibility impacts from slash burning and work with adjacent states to encourage smoke management policies as robust as Oregon's. The Regional Haze Long-term Strategy also describes DEQ's commitment to resourcing a biomass utilization workgroup that will make recommendations and inform future policy by identifying barriers to and opportunities to alternatives to burning, such as composting. DEQ is also committed to revising Oregon's Open Burning rules to clarify responsibilities and jurisdictions among multiple state agencies, counties and fire districts.

Comment #17
The State of Oregon has proposed a regional haze plan that does not require enough pollution reductions to make reasonable progress toward clean air goals for our parks and to support healthy air for directly affected communities close to haze-polluting facilities.

NPCA supports Oregon's State Implementation Plan (SIP) source selection process, and we were pleased with the chosen cost-effectiveness threshold of $10,000/ton. We were also pleased with DEQ's initial consideration of environmental justice concerns related to haze pollution.

However, Oregon has improperly used the four-factor pollution control analyses to allow 17 facilities the option to apply for plant site emission limits (PSEL). This approach is not consistent with the requirements of the Regional Haze Rule as they allow for short-term air pollution spikes that problematically contribute to localized air pollution in communities and hazy skies in parks.

With this proposed plan, Oregon will allow major paper mills such as Boise Cascade's Elgin Complex (Medford), Georgia Pacific's Wauna Mill (Clatskanie), and Roseburg Forest Products, as well as facilities in large urban neighborhoods like the Owens-Brockway Glass Plant (Portland) and Gas Transmission Northwest compressor stations, to continue to emit thousands of tons of controllable pollution, ignoring opportunities for cost-effective haze controls. The intent of the regional haze program is to select the highest level of control that meets four-factor analysis. Oregon's approach does not satisfy this intent.

Furthermore, cleaning up facilities like Owens-Brockway will not only restore air quality for national parks and public lands, but will reduce air pollution harms on people of color and low-income families. Residents of East and Northeast Portland have disproportionately shouldered the burden of industry for too long and Owens-Brockway should be required to cut emissions through pollution reducing control devices.

We urge you to revise this regional haze plan to ensure that it reduces air pollution through verifiable emission controls.

DEQ Response
In Section 5 of the proposed RH SIP, DEQ demonstrates that Reasonable Progress Goals for 2028 will meet a Uniform Rate of Progress toward natural visibility goals by 2064 in each Oregon Class 1 Area – the so called glidepath. This demonstration is based on Western Region Air Partnership regional scale modeling to which DEQ contributed Oregon emissions data. Where 2028 RPGs are slightly above the glidepath, DEQ has demonstrated through the required analysis of the four factors in Section 3.4 of the proposed RH SIP, that Oregon's Round 2 regional haze Long-term Strategy contains all "emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy" [40 CFR 51.308(f)(3)(ii)(A)].

DEQ carried out the agency's Round 2 Regional Haze Rule responsibilities that pertain to stationary sources under the authority of Oregon Administrative Rules Chapter 340 Division 223. Division 223 rules establish the Round 2 screening process that determines which facilities are subject to analysis of pollution controls based on the four factors (cost, time to install, remaining useful life, non-air and energy impacts). PSEL reduction is one of the compliance options provided in Division 223 if DEQ determines that Round 2 regional haze pollutant reduction is cost-effective, based on the four factors. For facilities where DEQ agreed that monitoring, equipment replacement, PSEL reduction or operational changes could achieve emission reductions consistent with reasonable progress, DEQ did not require control installation identified in January 2021 communications to facilities. Furnace shut down, as in the case of Owens Brockway, was also an allowed compliance option.

DEQ agreed in some cases that controls deemed cost effective in the January 2021 letters to sources were not technically feasible or that equivalent emissions could be achieved through other means (e.g. more efficient operations, furnace shut down) or that controls would be installed by a time certain if a source found they could not achieve agreed-upon emission reductions by other means.

Facilities have agreed to either an emission rate or percent reduction. Emission reductions are verifiable and enforceable through facilities' Title V permits, the stipulated agreements and orders, and by incorporation into the proposed RH SIP.

Comment #18
I would like to respectfully bring to your attention an error in the public posting of Appendix E to the rulemaking materials for the Oregon Regional Haze 2018-2028 State Implementation Plan (Modified: 9/3/21). Table 3-6 of the proposed Regional Haze SIP identifies DEQ's regional haze program findings for the sources that initially screened into review. Appendix E consists of documentation related to those determinations. One of those facilities included in Table 3-6 is Roseburg Forest Products-Riddle Plywood (Facility No. 10-0078). However, that facility is not correctly represented in Appendix E.

The PDF in Appendix E titled "10-0078-TV-01_PM_2019" opens up to the incorrect Roseburg Forest Products Co. (Roseburg) facility permit. The PDF included in the rulemaking materials is of Roseburg's Riddle Engineered Wood Facility, Title V Permit# 10-0013-TV-01; the correct PDF should consist of Roseburg's Riddle Plywood Facility, Title V Permit# 10-0078-TV-01.

DEQ Response
DEQ regrets the error and has now omitted the wrong permit from Appendix E of the proposed RH SIP and added a reference to the correct permit in section 3.7.3.5 of the proposed RH SIP.

Comment #19
DEQ Should Reconsider Measuring "Reasonable Progress" Via PSEL Reductions. DEQ viewed a Q/d (based on PSELs) as some of "the strongest evidence that emissions from facilities contribute to visibility impairment." But actual emissions, not PSELs, are more accurate both in (1) measuring a source's current contribution to regional haze and (2) evaluating whether reductions will result in "reasonable progress" as required by EPA regulations. EPA's guidance does not support using PSELs to calculate Q/d.

A Q/d calculated using actual emissions would allow DEQ to more accurately identify the key contributors to regional haze and prioritize emissions reductions from these sources. Tracking each facility's change in Q/d (based on actuals) over time would allow DEQ to more accurately measure true visibility improvement progress.

Measuring emissions by relying on reductions in PSELs may artificially represent "reasonable progress" because a source's actual emissions may not change upon a PSEL reduction.

DEQ's Use of PSEL in Its Screening Analysis Was Inconsistent. Certain emission sources, such as GTN's compressor stations, were precluded from reducing their PSELs in order to account for worst-case natural gas demand scenarios as required by the Federal Energy Regulatory Commission ("FERC") certification process. DEQ should clarify whether it evaluated other methods or opportunities for facilities to screen out of the requirement of completing four-factor analyses. Aside from allowing PSEL reductions to initially screen out such that a facility's Q/d was below 5.00 (and a four-factor analysis was therefore not required), DEQ never permitted a facility to reduce PSEL as part of its four-factor analysis or in subsequent analysis (e.g. evaluating a control technology's cost effectiveness).

DEQ Should Provide Greater Clarity in the "Criteria" It Used to Measure Cost Effectiveness. DEQ did not provide adequate documentation of its process in creating criteria and evaluating entities' cost-effectiveness analyses. DEQ should:
(1) Clarify whether it also consulted with EPA at this step; (2) Clarify what criteria were identified; (3) Clarify how those criteria were applied; (4) Clarify what "presumed cost-effectiveness" means, and how "presumed cost effectiveness"
was developed and applied.

DEQ Should Provide Greater Clarity on How It "Adjusted" Cost-Effectiveness Analyses. DEQ adjusted parties' cost-effectiveness analyses, but provided limited to no information regarding how it adjusted these analyses. It is unclear whether PSEL, interest rate, and useful life represents an exhaustive list or whether DEQ adjusted parties' submittals for other factors. However, based upon DEQ records, it appears that adjustments were not so limited and that DEQ staff were given the green light to make "additional adjustments . . . over and above the 'basic adjustments.'" DEQ should clarify the scope of adjustments DEQ staff were permitted to make, ideally by identifying the entire spectrum of cost categories that DEQ staff adjusted.

The draft SIP does not indicate what deference, if any, DEQ gave to parties' facility specific estimates (e.g., vendor quotes) for certain costs or factors in their cost-effectiveness analyses and in DEQ's adjustment of those costs. DEQ should clarify how it evaluated these facility-specific cost estimates and state whether it developed criteria for evaluating parties' facility-specific information.

DEQ should clarify subsequent reviews. As evidenced between parties' submittals and DEQ's decisions, DEQ also adjusted parties' cost-effectiveness submittals in this second review. DEQ should clarify its process for revising parties' submittals—e.g., whether it developed criteria for revisions and, if so, DEQ should provide information regarding those criteria. Lastly, DEQ should clarify the level of deference it gave, if any, to parties' facility specific estimates for certain cost items or factors in this second review. DEQ should also clarify whether it developed criteria for evaluating parties' facility-specific information in this second review.

DEQ Should Correct Certain Mischaracterizations of GTN in the Draft SIP. Certain references to GTN in the draft SIP, in comments submitted by the National Park Service ("NPS"), are inconsistent and erroneous.

DEQ Response
DEQ has included the entire comment letter from commenter 13 in in Appendix H of the 2018-2028 Regional Haze Plan. DEQ responds to the key elements of Comment 19 here.

DEQ should reconsider measuring reasonable progress with PSEL reductions
DEQ did not use PSELs to measure reasonable progress. DEQ relied on the regional modeling performed by WRAP to project reasonable progress by 2028, discussed in Section 5 of the proposed RH SIP. The 2028 Potential Additional Controls scenario was modeled based on emission reductions from actual emissions, not PSELs. The purpose of the initial screening was to assess the potential for facilities to have visibility impacts on nearby Class I areas now and in the future. For this initial screening, DEQ continues to assert that PSELs are the appropriate measurement to use. DEQ recommended this approach to the EQC as part of the regional haze rules (OAR 340-223) because the Regional Haze program requires planning and strategies for the long-term: attaining natural visibility by 2064. The EQC adopted those rules in July 2021. PSEL's are long-term planning tools and give regulated facilities flexibility and regulatory certainty to accommodate facilities' growth.

DEQ's use of PSEL in its screening analysis was inconsistent
Q/d<5.00 (based on PSELs) was the only method DEQ used to screen sources in or out of the requirement to conduct a four factor analysis. DEQ did not employ any other applicability screens. DEQ also used PSELs when evaluating the cost-effectiveness of controls, one element of the four factor analysis, for the same long-term planning reasons stated above. DEQ allowed sources to reduce PSELs as a compliance option at any point in the process - from initial screening through final agreements.

DEQ Should Provide Greater Clarity in the "Criteria" It Used to Measure Cost Effectiveness
DEQ used a cost/ton of pollution reduced, based on PSELs, as the only criteria to assess cost effectiveness. In assessing cost effectiveness, DEQ relied on information facilities supplied as part of the four factor analysis, any additional information (e.g. vendor quotes) that DEQ requested, and technical expertise of DEQ's engineers and permit writers.

DEQ Should Provide Greater Clarity on How It "Adjusted" Cost-Effectiveness Analyses.
DEQ adjusted the interest rate and remaining useful life to be consistent among all the facilities that underwent FFA. DEQ also exercised the professional judgment of its technical staff in adjusting the assumed efficiency that a pollution control could achieve. DEQ met several times with each facility subject to regional haze regulation and provided explanations and documentation of its calculations.

DEQ should correct certain mischaracterizations.
Comments submitted from the National Park Service are part of the public record, as are comments submitted by GTN, LLC and DEQ has included both comment letters in their entirety in Appendix H of the proposed RH SIP. DEQ does not deem it appropriate or necessary to respond to areas of disagreement among commenters.

Comment #20
Over the last few decades the Owens-Brockway facility (9710 NE Glass Plant Road Portland OR 97220) and OI-Glass parent has manipulated, and lied to, the DEQ frequently while subjecting the people of the local community to increased asthma; lead, arsenic, hexavalent Chromium (Cr VI) exposures; GHG releases (SO2, NOX, CO2); and toxic environmental releases into the local watershed.

The Owens-Brockway facility has no filtration devices, no scrubbers, has never been required to install them, and now, has little incentive to install any as long as the device of 'back room deals' with DEQ regulators remains a point of decision making. The fact that the facility shut down a furnace and moved the pollution across the river to Washington state is not a remedy for Regional Haze, as DEQ seems to want to believe, but a capitulation because the polluter is not being held responsible for continuing emissions from their other on-site furnaces. The community, via CAAT, still insists on representation, and we want the State to force the company to use filters. CAAT has even identified a filter-product remedy (ceramic catalyst filters) for the air pollution releases by the facility. These filters would address SO2 and NOX as well as Arsenic, Lead, and toxic air releases.

We now understand that the States capitulation regarding Regional Haze implementations may very well have happened as a result of a closed, non-inclusive, back room meeting with the polluter. It is not too far a stretch to say that the same may have happened for the other 17 facilities under the Regional Haze Implementation process.

CAAT is therefore asking the EQC to rescind any and all agreements that DEQ has made with the 16 facilities who, due to those backroom meetings and other informal, non-inclusive communications, will be allowed to continue fouling the air and harming the health of Oregonians, and revisit how to improve air quality and decrease regional haze here immediately.

DEQ Response
Owens-Brockway completed a four factor analysis, as Division 223 rules require, when total emissions of round 2 regional haze pollutants (SO2, NO_x and PM10), Q, divided by distance to the nearest Class 1 area, d, exceed 5.00. From that four-factor analysis, DEQ deemed ceramic catalytic filters a cost-effective pollution control of Round 2 regional haze pollutants, as documented in DEQ's September 2020 letter to Owens-Brockway. Division 223 rules permit options for facilities to comply with Regional Haze requirements and one of those options is reducing Plant Site Emission Limits at any point in the process to a level such that total Q/d is less than 5.00. In alignment with Division 223 rules and to maintain regulatory consistency, DEQ

did not require facilities agreeing to make changes such that Q/d < 5.00 to install controls. The agreements DEQ reached with all facilities, including Owens-Brockway, contain enforceable emission limits, as the federal Regional Haze Rule requires, and enforceable emission reductions over the 2018-2028 implementation period and beyond.

This facility is also regulated by other programs at DEQ. Through Cleaner Air Oregon, Owens-Brockway is required to complete a risk assessment to identify toxic air contaminant (TAC) emissions from their facility. Owens-Brockway completed multiple source testing events to quantify specific TAC emissions from their onsite furnaces and is in the process of completing a Level 4 Risk Assessment to determine whether any actions must be taken to reduce risk from their facility.

For criteria pollutants (federal, health-based standards), the facility is required to model emissions from Furnace D, which are evaluated relative to the 1-hour, health-based National Ambient Air Quality Standards. If the modeled concentrations are equal to or greater than the NAAQS, OB would be required to install controls or reduce production levels.

Also, under an enforcement Mutual Agreement and Order, Owens-Brockway is required to install Particulate Matter controls or shut down by June 2022. The MAO also contains an interim opacity limit with stipulated penalties of $18,000 per violation.

Comment #21
On behalf of the undersigned groups and Multnomah County, we respectfully submit these comments. As to the industrial facilities and their impacts on Class I areas, we incorporate by reference the comments authored by Earthjustice, National Park Conservation Association and others submitted on November 1, 2021. Our comments here are intended to provide a specific focus on the Department of Environmental Quality (DEQ)'s draft State Implementation Plan (SIP) and its address of prescribed burning and residential biomass/woodsmoke which are not addressed in the other written coalition comments.

The current draft SIP is insufficient in its proposed rules to reduce emissions from biomass burning/residential woodsmoke. Residential wood smoke may have a particularly pronounced effect in the Columbia River Gorge National Scenic Area due to geography, residential land use in the gorge, and proximity to population centers where residential wood combustion is common.

Amongst the 5 factors for long-term strategy are emissions reductions due to: ongoing air pollution control programs, basic smoke management practices for prescribed fire, and the anticipated 'net effect' on visibility due to projected changes in point, area, and mobile source emissions.

Section 4.6.2 of the SIP, which covers residential wood burning sources, does not adequately address biomass emissions. We would like DEQ to recognize the insufficiency of the HeatSmart Program as a main approach to reduce emissions. Numerous peer reviewed scientific studies show that woodstove changeouts that upgrade old stoves to "cleaner" woodstoves (like HeatSmart) do not meaningfully decrease pollution.

The current SIP fails to consider the 'net effect' of all indoor and outdoor residential burning on air quality and visibility within a region, nor all ways to mitigate it.

The draft SIP fails to mention the statewide woodstove changeout program which allots specific counties grant amounts to help their residents change out their woodstoves and the existing locally-backed education and woodsmoke curtailment programs in each County.

It also fails to mention federal ARPA funding- which has been allotted in the amount of $500,000 for woodsmoke changeouts in Multnomah County for the next biennium.

The SIP could be strengthened if it incorporated the recognition of additional grant funding needed to continue woodstove changeouts towards non-biomass devices, other policies mentioned in DEQ's 2016 report to the legislature, and the policy proposals from the Multnomah County 2021 woodsmoke working group.

This includes but is not limited to:

- Additional grant funding dedicated to providing woodstove changeouts for heat pumps or
- other non-biomass burning devices.
- More DEQ funding for locally run woodsmoke curtailment programs and public
- education programs
- Increased statewide education and outreach is needed because increasing awareness of
- the harms of woodsmoke is essential for emissions reduction
- enhanced coordination with other agencies to focus on air quality from wood burning.
- Tax credits, perhaps through clean energy initiatives.
- complete a statewide woodsmoke combustion inventory
- consider a permitting scheme for future commercial businesses who use a chiminea, chimney, or woodstove.

Smoke Management and Prescribed Burning
DEQ and Department of Forestry would need to consider the rules that allow burning of biomass debris, forest waste on private and public lands and consider volume restrictions. Agencies should limit all unnecessary pile burning and agricultural burning in Oregon. Education and no-burn alternatives should be encouraged and clarified- not in the next few years as stated in the SIP- but almost immediately. All permitted burning should provide scientifically supported data that shows its efficacy in preventing wildfire or providing ecological benefit (prescribed burning). Burning in lieu of forest, domestic or agricultural clean-up practices such as composting should be minimized and limited. We realize that woodburning and biomass is only one piece of the puzzle contributing to haze. But we urge you to flesh out your long-term strategy and enforceable rules to mitigate emissions.

DEQ Response
DEQ has included the entire comment letter from commenter 15 in Appendix G of the proposed RH SIP. DEQ responds to the key elements of Comment 21 here.

DEQ agrees with commenter that woodsmoke - from residential wood burning, biomass burning, and prescribed burning - is a substantial contributor to regional haze, as well detrimental to public health. DEQ conveys the extent of visibility impairment from woodsmoke and biomass burning in sections 2.3, 2.4 and 2.5 of the proposed RH SIP, generally by showing results of the WRAP modeling, analysis of IMPROVE monitoring, and modeled source apportionment. DEQ recognizes, though, that often woodsmoke is grouped in with larger categories - such as area sources - and it is not obvious what proportion is attributed to woodsmoke.

The current draft SIP is insufficient in its proposed rules to reduce emissions from biomass burning and residential woodsmoke
To draw more attention to strategies that address woodsmoke, prescribed fire and biomass burning, DEQ has reorganized Section 4 - the Long-term Strategy section of the proposed RH SIP based on the organization of the additional five factors in 51.308(f)(2)(iv)(A) - (E) (construction, smoke management, on-going programs, source retirement, and point, area, mobile sources). Strategies to address prescribed burning and forestry biomass burning are now under, "Smoke Management and Prescribed Burning for Wildland Vegetation Management." Strategies to address agricultural/non-forestry open burning are under “Area Source Strategy: Agricultural Open Burning.” And strategies to address residential wood burning are under, "Area Source Strategy: Residential Wood Heating."
DEQ has mentioned the importance of several elements from the reports and proposals the commenter suggests in the Long-term Strategy (Section 4 of the proposed RH SIP) to reduce woodsmoke emissions. DEQ has also elaborated on the scope of future rulemaking in the Heat Smart and Open Burning programs.

DEQ agrees with commenter on the urgency of educating communities and encouraging alternatives to burning. Prescribed burning is governed by the recently updated and SIP-approved Smoke Management Plan and DEQ does not expect to revise this plan in the near future. However, DEQ is actively pursuing solutions and identifying barriers to alternatives to open burning, both within the agency - such as permitting air curtain incinerators, and across agencies - such as the Biomass Utilization Work Group. The work is underway, including work such as education, outreach and collaboration with research institutions. Some of this work has been made possible by the passage of Senate Bill 762 - the omnibus wildfire bill -- and DEQ has elaborated upon this work in the LTS section to a greater extent than in the publicly noticed RH SIP.

Comment #22
Oregon’s proposed rules to implement the Regional Haze program gave DEQ powerful tools to reduce pollution. Many of the undersigned organizations submitted comments in support of these strong rules. The Q/d screening mechanism resulted in 32 of Oregon’s biggest polluters performing four-factor analyses, and the $10,000 cost-effectiveness threshold laid the groundwork for DEQ to be able to order 17 of these sources to install controls that would have improved visibility and protected public health. DEQ sent these facilities “control letters” reflecting DEQ’s decision as to which cost-effective control they would likely be required to install, based on the agency’s four-factor analysis.

Division 223 rules
However, after comments on the Division 223 rules were closed, DEQ fundamentally altered its approach without engaging in any kind of public process and without consulting stakeholders other than the regulated entities. Instead of ordering all 17 facilities to implement the reasonable progress controls identified through four-factor analyses, DEQ inexplicably chose to extend offers that allowed all but one of these facilities to exit the program or comply with the program without investing in the highly effective pollution-reducing technology that DEQ could—and should—have required these facilities to install to meet the state’s obligations under the regional haze program.

Nothing in Oregon’s rules allows DEQ to offer alternative compliance options that result in less effective emissions reduction measures, and nothing requires the agency to offer alternative compliance options at all.

Nothing in SIP reflects any determinations by DEQ that the reduced PSELs or other pollution-controlling operations steps in the Stipulated Agreements and Final Orders would "provide for equivalent reductions to those identified in its review and adjustment of the four-factor analysis." OAR 340-223-0110(2)(b)(C)–(E).

Alternative Compliance: Lowering Plant Site Emission Limits

Ultimately, DEQ only unilaterally ordered one of the 32 facilities that completed four-factor analyses to install reasonable progress controls. One facility voluntarily agreed to implement the reasonable progress control identified in DEQ's control letter. For the other 15 facilities that identified cost-effective controls, DEQ allowed them to voluntarily reduce their Plant Site Emission Limits (PSELs)—the high pollution limits contained in Oregon's air permits—or voluntarily take other less effective emissions-reducing steps instead of installing the reasonable progress controls DEQ indicated it would require them to install based on their four-factor analyses.

The only rationale DEQ offered for this choice is that the agency offered these off-ramps to facilities with actual emissions that would exclude them from the program if the threshold for inclusion in the program were based on the facility's actual 2017 emissions rather than their 2017 permitted emissions limits. See SIP at 35. This appears to be an after-the-fact attempt to rewrite the rules to change the screening threshold for inclusion in the Regional Haze program from a threshold based on permit limits—a threshold that brought 32 facilities into the program—to one based on actual emissions—a threshold that would have left out 18 of those facilities—without undergoing public scrutiny and comment on this approach. Eight of the facilities to which DEQ offered alternative compliance would still have been included in the program even if the threshold were based on their actual emissions rather than permit limits. DEQ's rationale for this choice simply does not explain DEQ's actions.

All but one of the off-ramp agreements with defined new PSELs allow facilities to continue emitting at levels above their 2017 emissions, which DEQ used as a baseline. In other words, those agreements will not result in any reductions from the baseline emissions level.

Equivalent Emission Reductions - Lack of demonstration

Nothing in the SIP suggests that DEQ analyzed whether the "alternative compliance" agreements that required emissions reduction measures different from the ones identified in DEQ's control letters provide equivalent reductions or studied the impact of these agreements on Oregon's Regional Haze strategy. Nothing in the SIP attempts to justify the off-ramping of 15 facilities by reference to any requirements of the Regional Haze program.

Section I(B) contains a table comparing the emissions reductions that would have resulted from ordering facilities to install cost-effective controls identified in their four-factor analyses versus those that will result (if any) from the measures in the "alternative compliance" agreements. The table does not reflect a perfect one to one comparison because of the variability in the conditions contained in the agreements. For example, some of the agreements lack defined PSELs and some contain multiple possible compliance options, such as installing a control device, changing a fuel source, reducing actual emissions by a certain percentage, ceasing operations, or accepting a reduced PSEL, or some combination thereof.

The "alternative compliance" options that DEQ extended to 15 of the 17 facilities that identified cost-effective controls all result in far fewer emissions reductions than would be achieved if those sources were required to install the reasonable progress controls identified in their four-factor analyses. Of the agreements with reduced PSELs, all but one allow sources to continue emitting at levels above their 2017 actual emissions levels, which DEQ used as the baseline for the SIP. In other words, the agreements for the sources with agreements containing defined PSELs will not result in any emissions reductions—and could even result in increased emissions—from the 2017 baseline DEQ used to develop the SIP.

Clean Air Act and Regional Haze Rule violations/Lack of Four Factor Analysis justification

DEQ's decision to allow some of Oregon's largest stationary sources of haze-forming pollution to reduce the overhead in their air permits instead of installing pollution controls that satisfy a four-factor reasonable progress analysis violates the Clean Air Act and federal Regional Haze rules.

The Clean Air Act requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. States may not subsequently reject measures they previously deemed reasonable.

DEQ's decision to reject reasonable progress controls and instead enter agreements not based on a four-factor analysis violates the Regional Haze Rules regardless of whether Oregon can still stay on the glidepath.

Oregon has failed to adequately justify its decision. Oregon's modeling to demonstrate how the SIP relates to Oregon's reasonable progress goals is based on the assumption that facilities would install and operate the specific controls identified in DEQ's control letters based on the facilities' four-factor analyses. DEQ cannot satisfy the Regional Haze program's requirements without analyzing the effect of these back-room agreements and comparing the emissions reductions from the agreements to the emissions reductions from reasonable progress controls. Oregon has not used an appropriate framework for exempting facilities from the requirement to install reasonable progress controls and instead selected the measures in the alternative agreements that in most cases reflected business as usual.

A state's SIP must be supported by a reasoned analysis and include a description of the criteria the state used to determine which sources or groups of sources it evaluated and how the four statutory factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. The state must document the technical basis for the SIP, and include that information in the plan when they make it available for public comment.

Oregon cannot determine the emissions reduction measures necessary to make reasonable progress without conducting the statutorily required four-factor analysis of its emissions reduction strategies.

Without analysis to support DEQ's decision to off-ramp facilities where reasonable progress controls were available or analysis of how off-ramping facilities instead of ordering them to install cost-effective controls identified in their four-factor analyses will affect Oregon's progress towards natural visibility, the SIP violates the Regional Haze rules, which require every SIP to contain a description of "how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy."

Omitting complete cost analysis documentation from the SIP violates the requirement in the 2017 Regional Haze rules to "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I area it affects" including the "cost and engineering information on which they are relying to evaluate the costs of compliance, the time necessary for compliance, the energy and non-air quality impacts of compliance and the remaining useful lives of sources."

Not meeting Reasonable Progress Goals or Uniform Rate of Progress
The modeling in Oregon's SIP shows that if DEQ had ordered all 17 facilities that identified cost-effective controls in their four-factor analyses to install those controls, Oregon would be on or below the glidepath for some—but not all—of the Class I areas. See SIP at 75. In other words, Oregon's Regional Haze strategy depends on taking steps DEQ has chosen not to take, plus other emissions reductions.

DEQ's projections for 2028 are based on the assumption that DEQ would order stationary sources to install "controls recommended from DEQ's review of initial four factor analyses submittals[.]" SIP at 75. The projections do not account for the "alternative compliance" option that 15 of these stationary sources received and accepted. In other words, even if Oregon had ordered all 17 facilities that identified cost-effective controls to install reasonable progress controls, Oregon would not be able to achieve its reasonable progress goals for most Class I areas.

By relying on this modeling in the SIP after DEQ declined to order these facilities to install reasonable progress controls, the state has misled the public about its ability to achieve the state's reasonable progress goals and stay below the glidepath.

Lack of Environmental Justice Consideration
By allowing 15 facilities to avoid reducing their emissions at all or to take less effective emissions reduction steps, Oregon has prioritized the interests of the regulated entities over the interests of those facilities' neighbors whose health and well-being are threatened by NOx, SO2, and PM and who would have benefitted from more effective controls.

While DEQ carefully established a protocol and analyzed the environmental justice and vulnerable populations "score" of each facility with cost-effective controls identified in its four-factor analysis, it then seemingly ignored this information when making consequential decisions: in place of actual significant reductions in emissions that would be achieved though the implementation of four factor reasonable progress control analyses the agency instead established alternative compliance to these facilities regardless of the environmental justice impacts and the impacts on vulnerable populations.

Owens-Brockway
DEQ's backroom agreement with Owens-Brockway underscores the environmental justice costs of allowing some of the state's largest polluters to off-ramp from the Regional Haze Program without requiring actual emission reductions equivalent to what could have been achieved from requiring the facility to install reasonable progress controls. Although Owens-Brockway voluntarily shut down one of its two furnaces in June 2020 and DEQ ordered the facility to that furnace shut down in June 2021 in connection with an enforcement action, the remaining furnace still exposes neighboring communities to SO2 and NOx—pollutants that can adversely affect lung function and worsen asthma attacks. Modeling recently uncovered that, even when only the sole remaining furnace is running, the Owens-Brockway facility may be causing or contributing to violations of the 1-hour SO2 and 1-hour NOx National Ambient Air Quality Standards designed to protect public health and the environment. The new permit emission

limits in the “alternative compliance” agreement do not require Owens-Brockway to in any way change its operations, effectively resulting in no actual emission reductions on the ground.

Federal Land Manager Consultation
DEQ’s consultation with the Federal Land Managers, including National Park Service, happened before DEQ executed these back-room agreements. Given the significance of this change in direction, there is a real question as to whether DEQ has satisfied the requirement to consult with Federal Land Managers no less than 60 days prior to a public hearing or public comment opportunity.

We agree with the National Parks Service’s comments on ten facilities’ cost analyses and urge DEQ to adopt and require the reasonable progress controls identified by the Park Service in the revised SIP.

The National Park Service repeatedly notified DEQ of errors in the cost analyses for 10 facilities, including incorrect equipment life, interest rate, retrofit factors, and assorted errors to inputs to SCR and other cost algorithms. See SIP at App’x G. Making these corrections often drastically improves the cost-effectiveness of controls at many facilities. It is unclear whether DEQ adequately revised its analysis to correct errors and omissions. Some facilities failed to provide adequate documentation to support their cost analyses, including full vendor information, but nothing in the SIP indicates whether DEQ ever obtained this information to confirm the facilities’ cost analyses.

Conclusions
For all of the foregoing reasons, we urge DEQ and EQC to revise Oregon’s State Implementation Plan. The proposed Plan violates federal law, and will not achieve the emissions reductions necessary to protect visibility in Oregon’s Class I areas. The proposed SIP misses the opportunity to protect the health of environmental justice communities in Oregon and evades the Regional Haze requirements that obligate the state to undertake actions in keeping with this objective.

To comply with the Regional Haze rules, DEQ must vacate its “alternative compliance” agreements, which are plainly contrary to the requirements of the Clean Air Act and Regional Haze rules and instead require these facilities to install and operate the most effective reasonable progress controls. Oregon’s SIP must demonstrate that DEQ selected and ordered reasonable progress controls for 17 facilities based on a proper four-factor analysis, taking into account environmental justice, and that any orders or agreements deliver emissions reductions at least equivalent to those that would be obtained through the installation of the reasonable progress controls identified in DEQ’s control letters.

DEQ Response
DEQ has included Comment 22 in its entirety in Appendix G of this Regional Haze Plan. DEQ responds to key elements of the comment here.

Division 223 Rules
DEQ proposed Division 223 Regional Haze Rules, which EQC adopted in July 2021, to give DEQ the authority to issue orders to facilities based on visibility standards and to codify the process by which DEQ screened in sources for potential regulation and analyzed potential control of the sources' haze-forming emissions. Div. 223 rules allow DEQ to offer alternative compliance to sources where DEQ has deemed pollution control to be cost-effective based on a four factor analysis. DEQ, as a matter of regulatory consistency, made alternative compliance

options available to all sources. DEQ sought to reach agreement with as many facilities as possible to secure enforceable agreements for emission reductions and include them in the publicly noticed RH SIP.

DEQ acknowledges that Section 3.7 of the original publicly noticed RH SIP, Facility Specific Findings and Results, contained minimal explanation of how DEQ evaluated alternative compliance options relative to the potential emission reductions from cost effective controls. DEQ has added more explanation to Section 3.7 of the proposed RH SIP.

Alternative Compliance: Lowering PSELs
Plant site emission limits are enforceable upper limits; PSELs give sources regulatory certainty and flexibility to grow operations without requiring permit modifications. With that flexibility comes a trade-off: sources must accept the regulatory consequences of the highest allowable emission, not simply their actual current emissions. In developing regional haze rules that allow sources to comply by lowering PSELs, DEQ acknowledges that emissions prevented in the future are different from current emissions reduced in the short-term. Still, in the context of the regional haze program requirements to attain natural visibility in Class 1 areas by 2064, DEQ asserts that long-term planning to prevent emission increases is an appropriate and effective means of reaching natural visibility targets. DEQ followed a conservative approach ($Q/d \geq 5.00$, based on PSELs) to capture the sources likely to be the greatest contributors to visibility impairment now and into the future. DEQ followed that conservative screening procedure with a conservative cost-effectiveness threshold of $10,000/ton, also based on PSEL, to evaluate pollution controls. As opposed to an approach based on actual emissions, this PSEL-based approach brought in more sources required to undergo four factor analyses and resulted in more sources being required to lower their emissions based on DEQ deeming controls cost-effective.

The commenter points out that DEQ also considered a facility's actual emissions in the initial Q/d screening; the commenter is correct that DEQ allowed facilities whose actual Q/d was less than 5.00 to agree to lower their PSEL so that PSEL Q/d was less than 5.00 and thereby screen out from the requirement for four factor analysis. But this allowance was available to all sources at any time from the beginning of the Round 2 regional haze process; DEQ did not allow this screening out only after EQC adopted the Division 223 rules, as the commenter seems to assert. If a facility that went through FFA later decided to lower PSEL so $Q/d < 5.00$, DEQ was consistent in not requiring that facility to install controls that DEQ had deemed cost-effective. Had the facility agreed to lower PSELs to $Q/d < 5.00$ at the beginning of the process, that facility would not have been required to conduct an FFA and no cost effective controls would have been identified. In response to commenters assertion that DEQ allowed sources to exit the regional haze program, DEQ wishes to make clear that PSEL reductions are in no way an "off ramp" or an exemption from regional haze rule requirements. PSEL reduction is a permanent requirement in order to comply with the regional haze rule and is enforceable through the proposed RH SIP and through facilities' Title V permits.

Emission Reduction Equivalency Demonstration
For each source opting for alternative compliance, DEQ deemed that alternative compliance could "provide for equivalent reductions to those identified in its review and adjustment of the four-factor analysis." DEQ deemed alternatives to be capable of achieving equivalent reductions by considering, for example:

- Difference in potential emissions (PSELs) between the two scenarios (4FA vs SAFO)
- Difference in expected actual emissions (at the production levels at which the facility normally operates) between the two scenarios (4FA vs SAFO)

- Level of uncertainty about technical feasibility of the 4FA controls
- Level of uncertainty about the costs of the 4FA controls

DEQ appreciates the detailed calculations the commenter provided to compare potential reductions from control installation with reductions achievable through the Stipulated Agreements and Final Orders. As the commenter points out, it is challenging to precisely quantify potential reductions from the SAFOs because of several factors unknown at this time. That is in part why DEQ included measurement and monitoring requirements as well as contingencies, such as SCR installation if emissions reductions cannot be achieved by other means, in the SAFOs.

In response to this and other comments, DEQ has negotiated and included SAFO addenda and has incorporated permit conditions by reference into the proposed RH SIP, where EPA in their comments had deemed emission rate, measuring, monitoring and reporting information lacking. The proposed RH SIP incorporating by reference the monitoring, record keeping and reporting requirements of the Title V permits makes those compliance requirements doubly federally enforceable.

Clean Air Act/Regional Haze Rule/Four Factor Analyses Requirements
DEQ agrees with the commenter that the Regional Haze Ruel requires DEQ to "evaluate and determine emission reduction measures necessary to make reasonable progress by considering" the four statutory factors: cost of compliance, time to install, energy and non-air environmental effects, and remaining useful life of the emission source [CFR 51.308 (f)(2)(i)]. DEQ does not agree that once DEQ has deemed that pollution control is cost-effective (which DEQ did based on a conservative threshold of $10,000/ton) that alternative compliance - other means to achieve emission reductions, such as operational changes or emission unit replacement - must undergo its own four factor analysis, as the commenter seems to suggest.

The commenter recommends that the FFAs and January 2021 letters to facilities be included in the proposed RH SIP, as well as technical information, such as DEQ's FFA reviews and adjustments, to demonstrate the technical basis on which DEQ relied to determine emission reduction measures necessary to make reasonable progress toward natural visibility in Class 1 areas. DEQ's response below (Reasonable Progress Goals/Uniform Rate of Progress Demonstration) refers to the sections of the proposed RH SIP in which DEQ has detailed the technical information on which the agency relied, but DEQ does not agree that details of all reviews, adjustments and calculations must be included in the proposed RH SIP to document the technical basis for decisions.

DEQ's preference is to include in the proposed RH SIP only those elements required by the Regional Haze Rule and for which DEQ is seeking EPA's approval and does not agree that the information the commenter recommends is required. Still, the FFAs and facility correspondence are posted on DEQ's regional haze webpage and will remain part of the permanent public record of the Round 2 regional haze process. In addition, all written communication and information exchanged between facilities and internally among DEQ staff are public information and available for inspection upon request.

Reasonable Progress Goals/Uniform Rate of Progress Demonstration
DEQ has documented in several sections of the proposed RH SIP the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which DEQ relied to determine the emission reduction measures that are necessary to make reasonable progress: Sections 2.1 and 2.2 (Visibility Impairment based on IMPROVE data; Section 2.3 (Emissions

Inventory Analysis), Section 2.4 (Pollutant Components of Visibility Impairment based on IMPROVE data); Section 2.5 (Source Apportionment of Visibility Impairment); Section 3.1 (Q/d screening process), Section 3.4 (Four Factor Analysis); Section 3.7 (Facility-specific Findings and Results). DEQ summarizes the technical basis for Long-term Strategy in Section 4.1of the proposed RH SIP. In addition to internal DEQ staff expertise and professional judgment, DEQ relied to a large extent on the regional model (developed through the Western Regional Air Partnership) and the analysis of data collected through the IMPROVE monitoring network.

DEQ acknowledges and confirms the commenter's point that Potential Additional Control information that DEQ submitted to WRAP in September 2020 was input for the modeling of 2028 reasonable progress goals for each Class 1 area. DEQ also confirms that the Potential Additional Controls were those evaluated in the four factor analysis process. DEQ wishes to point out that the RPGs are 2028 visibility projections from a complex, regional scale model which reflects potential emission reductions, particularly those from point source controls (i.e. potential additional controls) and also regional emission reductions (e.g. marine fuel replacement). DEQ has deemed alternative compliance controls and PSEL reductions capable of achieving equivalent emission reductions to the controls evaluated through a four factor analysis and therefore commits to attaining these RPGs. DEQ also recognizes that meeting visibility goals in 2028 and beyond will also require implementation of all elements in the Long-term Strategy - including policies to reduce emissions from area and mobile sources.

Environmental Justice Considerations

DEQ acknowledges that communities living near stationary air pollution sources are at higher risk for exposure to air contaminants, as well as resultant short-term illness and increased morbidity in the long-term. DEQ also acknowledges that these communities are often of lower income and wealth, may be linguistically isolated, and residents of these communities are more likely to be people of color. And DEQ acknowledges that words on paper and websites are insufficient responses to the inequitable pollution burden these communities have borne and continue to bear. Establishing a vulnerable population score was how DEQ chose to consider the fourth factor – non-air environmental effects - and this informed DEQ's decisions throughout the entire regional haze process.

Owens-Brockway

Owens-Brockway completed a four factor analysis, as Division 223 rules require, when total emissions of Round 2 regional haze pollutants (SO_2, NO_x and PM10), Q, divided by distance to the nearest Class 1 area, d, exceed 5.00. As previously written, Division 223 rules permit options for facilities to comply with Regional Haze requirements and one of those options is reducing Plant Site Emission Limits at any point in the process to a level such that total Q/d is less than 5.00. In alignment with Division 223 rules and to maintain regulatory consistency, DEQ did not require facilities agreeing to make changes such that Q/d < 5.00 to install controls. The agreements DEQ reached with all facilities, including Owens-Brockway, contain enforceable emission limits, as the federal Regional Haze Rule requires, and enforceable emission reductions over the 2018-2028 implementation period and beyond.

Regarding NO_x, SO_2 and PM emissions from Furnace D: the facility is required to model emissions from Furnace D, which are evaluated relative to the 1-hour, health-based National Ambient Air Quality Standards. If the modeled concentrations are equal to or greater than the NAAQS, OB would be required to install controls or reduce production levels. Also, under an enforcement Mutual Agreement and Order, Owens-Brockway is required to install Particulate Matter controls or shut down by June 2022. The MAO also contains an interim opacity limit with stipulated penalties of $18,000 per violation.

Federal Land Manager Consultation
DEQ responded to NPS comments sent during the consultation period and those responses were in the publicly noticed RH SIP (August 2021). In those responses, DEQ described the changes and adjustments it made to FFAs to assure consistent reviews. DEQ also explained the reasons why DEQ did not make other corrections (e.g. property tax, retrofit factors) once DEQ determined that controls were cost effective, at or below the $10,000/ton threshold. The purpose of the FFA was to identify that controls were cost effective, based on a conservative threshold of $10,000/ton, not to complete a precise cost analysis of controls.

DEQ valued and considered all input received from the National Park Service. DEQ consulted with NPS on these occasions: January 28, 2020; September 25, 2020; February 19, 2021; May 27, 2021; June 30, 2021, and July 15, 2021. At the July 15 meeting with NPS, DEQ presented a spreadsheet that summarized DEQ's findings for each of the 32 facilities subject to four factor analysis and any tentative agreements with facilities if they had been reached. On July 23, 2021, DEQ provided agency files and documents related to DEQ's full cost analyses and pollution control determinations for each facility. In addition, NPS submitted written comment on these occasions: April 2, 2021; June 3; July 1; July 7; July 15 and August 2, 2021. Each of these interactions provided NPS opportunities to meaningfully inform DEQ's decisions on the long-term strategy, as the Regional Haze Rule requires.

Comment #23
The proposed Regional Haze Implementation Plan does not adequately account for the substantial health and safety risks from wildfire caused by limiting the use of prescribed fire.

It is within the discretion of DEQ to increase the projected emissions from prescribed fire to account for these tradeoffs, allowing for more use of prescribed fire in the state. We request that DEQ use the endpoint adjustment in the uniform rate of progress glidepath toward reduced visibility impairment in Class 1 Areas as authorized under 40 CFR 51.308(f)(1)(vi)(B) in the Proposed Regional Haze Implementation Plan to include existing and projected increases in levels of prescribed burning.

Prescribed fire is the most effective method for reducing surface fuels to moderate fire behavior. Smoke management regulations remain a major limiting factor for increasing use of prescribed fire on Federal and private lands alike.

While we are supportive of efforts to boost the economic viability and adoption of other fuel management tools that have lower smoke impacts, such as biomass utilization, it is not realistic for DEQ to expect them to be deployed at scale or in rugged locations. Prescribed fire often only costs a few hundred dollars an acre, while chipping, specialized kilns, and other options cost thousands per acre. Mechanical thinning is effective, but not as effective as prescribed fire, and in some cases can make fire risk worse if not followed with prescribed fire because of surface fuels. Regulatory decisions should be based on the opportunities and challenges of fuel reduction tools as they are used today, not on optimistic predictions. Additionally, these other options often don't have the same ecological benefits of prescribed fire.

Holding the level of prescribed fire constant runs contrary to the actions of other state and Federal agencies to address the impacts of wildfire. Federal and state land management agencies have been building programs to increase the scale, pace, and quality of forest restoration across all ownerships. Every appropriations package under consideration in Congress right now directs an unprecedented increase in funding for fuels management, including prescribed fire. The Governor’s Wildfire Council recommends increased use of prescribed fire, and several provisions of 2021 SB 762 (Governor’s Omnibus Wildfire Bill) aimed to facilitate this through both funding of fuels projects and the creation of new programs to support prescribed fire capacity in the state. In contrast, Implementation Plan states that the two main objectives of the Smoke Management Plan are to minimize smoke emissions from prescribed burning and promote development of techniques that minimize or reduce emissions, such as utilization of forestland biomass.

Smoke from prescribed fire should be considered in the context of the dangerous conditions in Oregon forests. We strongly urge you to adjust the glidepath of uniform rate of progress toward reduction of visibility in Class 1 Areas to accommodate more acres of prescribed fire in the state.

DEQ Response
DEQ acknowledges that prescribed burning is an accepted and effective practice to minimize the risks from catastrophic wildfires. DEQ will continue to regulate prescribed burning through the Smoke Management Plan and in partnership with the OR Dept. of Forestry, US Forest Service, local governments and fire districts. Implementation of the regional haze long-term strategy does not include limiting or reducing the use of prescribed burning as a management tool. The long-term strategy will, however, include research, cross agency collaboration, and eventually rulemaking to identify and remove barriers to other biomass utilization techniques; pursuit of alternatives to burning does not require active discouragement or reduction of prescribed burning when that is the most appropriate management tool. DEQ acknowledges the likelihood that prescribed burning will increase in the coming years but remains unconvinced that redefining “natural conditions” by adjusting the glidepath to accommodate prescribed fire use is in line with the statutory construct or goals. Smoke from prescribed fire contributes to visibility impairment and is controllable, unlike wildfire; for that reason, DEQ continues to find it most appropriate to compare visibility goals to a glidepath that is not adjusted to remove effects from prescribed fire.

Comment #24
We are a biomass fueled power plant. Power plants sell their power to a utility that uses it to power to the grid. The contract dealing with this is called a Power Purchase Agreement (or PPA for short). The pricing paid for the power is therefore fixed in the PP A. The PP A for Biomass One LP ends on December 31, 2026. Producing power from waste wood is one of the most expensive methods of power production. In essence we are waste reduction facility the makes electricity and Biochar as byproducts. Given the current projected power prices beginning in 2026 we will not be able to afford to continue operating as the projected price of the fuel would force us to operate at a loss.

There are a few areas where we disagree with the DEQ's chosen approach. The first and most important area is accounting for our regional haze pollutant emissions. While the DEQ counts all or our emissions of pollutants (both fugitive and point) we are not allowed credit for the reductions to total regional haze pollutants emitted in the State. If the emissions that were avoided by burning forest biomass in our boilers rather than open burning it (in 2020 using actual values) we fall well below the Q/d for inclusion in the program. If we average the last eight years we are actually a net reducer of regional haze pollutants.

DEQ ignored the findings by our consultant in the four factor analysis. Our consultant found that first of all we have all the technically feasible control technology for our specific situation. The DEQ has taken the position that Selective Catalyzed Reduction technology is feasible for biomass fired power boiler even though it has never been successfully applied to a biomass fired power boiler of our size.

The second disagreement we have with them is in determining cost effectiveness. They chose a value of $10,000 per ton of pollutant removed to be cost effective. For a small facility such as ours this is not a "reasonable" value to determine cost effectiveness. For a large lumber mill that can pass the cost along to the consumer in the form of a price increase it may be reasonable but not to a facility with a low profit margin and no real way to increase revenue to offset the cost of the technology.

DEQ chose a thirty year amortization program (at an interest rate below what our consultant believed could be found) for everyone in the program. While in some ways it makes sense to put everyone on the same amortization basis it should be rooted in reality. The longest life expectancy for any of the budgetary estimates we received was twenty years. The result of this was to make the cost artificially low compared to the $10,000/ton threshold. Because of the short amount of time remaining on our current PPA there would be no way to acquire the amount of capital required to install the SCR technology even if we could somehow afford it.

We do want to express our appreciation to the DEQ for working with us to draft an SAFO that allows us to operate in our current configuration for the duration of our current PPA. The requirement to install SCR treatment for NOx if we get a renewal of the PP A makes it much more likely for us to have to terminate operations as it greatly increases the revenues required for the Plant to continue operations. We still feel that we should not have been included in the Program, however, we do appreciate being allowed to complete the current contract period.

DEQ Response
DEQ and Biomass One met several times in spring and summer 2021, at which times DEQ considered all information Biomass One provided. DEQ applied consistent criteria and adjustments to the four factor analyses of all facilities, regardless of industrial sector, as the Regional Haze Rule and Oregon rules, Division 223, require. DEQ acknowledges Biomass One's disagreement, but DEQ continues to deem SCR technically feasible and cost-effective. As stated in the SAFO, which Biomass One voluntarily entered, SCR will be required if Biomass One continues to operate beyond 2026.

Comment #25
I am a resident of Multnomah County and concerned about air quality and visibility in Oregon. I am particularly concerned about haze caused by air pollutants. I represent Woodsmoke Free Portland and have been working closely with Oregon Environmental Council. My comments focus on air quality problems and haze caused by residential wood burning, which appears to have minimal focus in DEQ's draft state implementation plan. Portland has some of the worst air quality in the U.S., EPA has ranked Portland worst for respiratory distress; it is well known that woodsmoke is a leading source of this air pollution. The draft plan does not thoroughly address open burning or residential biomass. It merely mentions the HeatSmart program, which requires uncertified stoves to be removed at the time of home sale. Based on research, we know that replacing wood stoves with wood stoves, even EPA certified woodstoves, does not produce improved air quality. We need other tools to reduce this significant source of haze. We need an updates statewide woodstove inventory, an emission inventory, and need to contemplate other policy ideas from the Multnomah County Woodstove Working Group - which DEQ participated in. For example, grant funding for heat pump change-outs for existing woodstoves; ensuring year-round burn ordinances to account for the now-regular summer wildfire season.

These same pollutants also fuel the climate crisis and consequences are alarming: wildfires, raised sea levels, melting glaciers at national parks across the country. The same sources of pollution causing haze disproportionately affect those living closest to the sources, most often communities living near the poverty line and communities of color.

I urge you to give more attention in your draft to biomass air pollution and ways to mitigate it. Anecdotally, on a recent drive from Otis, Oregon through Salem and on into Portland, the amount of haze in that large area was stunning: visible from the road all kinds of biomass burning, piles, residential burning, debris, forestry burning as they clean up from the wildfires. We need scientifically informed, preventative prescribed burns but we need to minimize unnecessary burning and use other methods like composting. In Multnomah County, 95% of burning is for ambiance, only 5% is for heat, and that small percent produces 50% of winter-time haze.

DEQ Response
DEQ agrees with commenter that woodsmoke - from residential wood burning, biomass burning, and prescribed burning - is a substantial contributor to regional haze, as well detrimental to public health. DEQ conveys the extent of visibility impairment from woodsmoke and biomass burning in sections 2.3, 2.4 and 2.5 of the proposed RH SIP, generally by showing results of the WRAP modeling, analysis of IMPROVE monitoring, and modeled source apportionment. DEQ recognizes, though, that often woodsmoke is grouped in with larger categories - such as area sources - and it is not obvious what proportion is attributed to woodsmoke.

To draw more attention to strategies that address woodsmoke, prescribed fire and biomass burning, DEQ has reorganized Section 4 - the Long-term Strategy section of the proposed RH SIP based on the organization of the additional five factors in 40 CFR 51.308(f)(2)(iv)(A) - (E) (construction, smoke management, on-going programs, source retirement, and together: point, area, mobile sources). Strategies to address prescribed burning and agricultural and forestry biomass burning (DEQ refers to this as open burning) are now under, "Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs." Strategies to address residential wood burning and non-agricultural/non-forestry open burning are under, "Projected changes in point, area, and mobile source emissions."

DEQ has mentioned the importance of several of the woodsmoke reduction policies that commenter 15, as well as this commenter, suggest, in the Long-term Strategy (Section 4 of the proposed RH SIP). DEQ has also elaborated on the scope of future rulemaking in the Heat Smart and Open Burning programs.

DEQ is actively pursuing solutions and identifying barriers to alternatives to open burning, both within the agency - such as permitting air curtain incinerators, and across agencies - such as the Biomass Utilization Work Group. DEQ has also partnered with Oregon State University to conduct a statewide survey of residential wood heating and DEQ will use the results of that survey - due the first half of 2022 - to update and enhance the statewide emissions inventory.

Comment #26
The Regional Haze Rule and plan are an important tool for protecting air quality and visibility in the Columbia River Gorge National Scenic Area and Class 1 areas in the state. The regional haze program also reduces pollution in Oregon communities and benefits human health.

Unfortunately, the draft plan falls short of the requirements of the Clean Air Act and the Regional Haze Rule. The draft plan does not appear to require actual pollution reduction from any major sources that DEQ identified as contributing to regional haze, and instead allows polluters to reduce their maximum pollution levels in their permits without having to reduce actual pollution levels through cost effective controls.

The way the plan is drafted, it appears industry can increase pollution above current levels, resulting in no reductions - it would just reduce the level of pollution allowed under the permit. This could undermine Oregon's strategy for reducing haze causing pollution. DEQ has also excluded one of the largest CAFOs int he country from the draft plan, located east of the Columbia River Gorge National Scenic Area, which contributes to haze, particularly in the winter months in the Gorge and Class 1 airsheds east of that facility. Threemile Canyon farms emits a large amount of ammonium nitrate, that DEQ has estimated results in 50% of the visibility impairment in the Columbia River Gorge. This CAFO should have been included int he list of facilities that had to develop pollution controls in Round 2 of the Regional Haze program. DEQ recognizes this as a problem but relies on this unfunded Dairy Air Quality program to reduce emissions. I'm active on the Oregon Legislature and I do lobby for good budgets and funding and have not been contacted by DEQ to inform us about opportunities to support this. Likely polluters contributing to this problem do not support funding for this program, so it would seem it’s a dead end. That's why Friends has recommended several times that these sources be included in the Regional Haze program.

When DEQ proposes exempting polluters from installing pollution controls, we're curious how much outreach was done to the communities that are directly affected by these polluters- surrounding communities, many of them low-income and at-risk populations. Overall, Friends hopes the draft plan requires real pollution reduction to protect the health of our communities and protect visibility in special places like the Gorge.

DEQ Response
In developing regional haze rules that allow sources to comply by lowering PSELs, DEQ acknowledges that emissions prevented in the future are different from current emissions reduced in the short-term. Still, in the context of the regional haze program requirements to attain natural visibility in Class 1 areas by 2064, DEQ asserts that long-term planning to prevent emission increases is an appropriate and effective means of reaching natural visibility targets. DEQ followed a conservative approach ($Q/d \geq 5.00$, based on PSELs) to capture the sources likely to be the greatest contributors to visibility impairment now and into the future. DEQ followed that conservative screening procedure with a conservative cost-effectiveness threshold of $10,000/ton, also based on PSEL, to evaluate pollution controls. As opposed to an approach based on actual emissions, this PSEL-based approach brought in more sources required to undergo four factor analyses and resulted in more sources being required to lower their emissions based on DEQ deeming controls cost-effective.

DEQ carried out the agency's Round 2 Regional Haze Rule responsibilities that pertain to stationary sources under the authority of Oregon Administrative Rules Chapter 340 Division 223. Division 223 rules establish the Round 2 screening process that determines which facilities are subject to analysis of pollution controls based on the four factors (cost, time to install, remaining useful life, non-air and energy impacts). PSEL reduction is one of the compliance options provided in Division 223 if DEQ determines that Round 2 regional haze pollutant reduction is cost-effective, based on the four factors.

DEQ agreed in some cases that controls deemed cost effective in the January 2021 letters to sources were not technically feasible or that equivalent emissions could be achieved through other means (e.g. more efficient operations, engine shut down) or that controls would be installed by a time certain if a source found they could not achieve agreed-upon emission reductions by other means. For facilities where DEQ agreed that monitoring, equipment replacement, PSEL reduction or operational changes could achieve emission reductions consistent with reasonable progress, DEQ did not require control installation identified in January 2021 communications to facilities. Still, through the SAFOs, facilities are held to either an emission rate or percent reduction. Emission reductions are verifiable and enforceable through facilities' Title V permits, the stipulated agreements and orders, and by incorporation into the proposed RH SIP.

DEQ agrees with commenter that area emissions from agricultural operations contribute to regional haze in the Columbia River Gorge National Scenic Area and Class 1 areas in Oregon. The air emissions from the agricultural operations at the facility the commenter mentions are not covered under the source's stationary source permit, as the EQC is prohibited from regulating most emissions from agricultural operations. Still, DEQ has included strategies to reduce haze-forming emissions from agricultural sources in the proposed RH SIP Long-term Strategy (Section 4 of the RH SIP), recognizing the cross-agency challenges in this area. DEQ has committed to working with the OR Dept. of Agriculture to develop policies that, at a minimum, incentivize best management practices, such as capturing ammonia area source emissions. DEQ has also committed in the long-term strategy to developing and refining the state's ammonia emission inventory and seeking EPA's assistance in that endeavor.

Comment #27
The Oregon Department of Environmental Quality's (DEQ) Draft Regional Haze Plan fails to meet the requirements of the Clean Air Act and the Regional Haze Rule. The draft plan allows polluters to reduce maximum pollution levels in their permits without having to reduce actual pollution levels through cost-effective controls. The way the plan is drafted, industries could increase pollution above current levels resulting in no reductions of haze-causing pollutants.

I am very concerned that the draft plan does not require pollution reductions from major sources that DEQ identified as contributing to regional haze in Oregon. Three Mile Canyon Farms, located in Boardman, Oregon, is responsible for emitting huge amounts of ammonium nitrate.

Burning agricultural and orchard waste is another unnecessary source of air pollution, waste that, with a little effort, could be put to useful purpose.

It appears that the draft plan lets polluters off the hook while surrounding communities and special places like the Columbia River Gorge continue to be subjected to air pollution.

DEQ Response
Please see DEQ Response to Comments 10, 13, 14 and 16.

Comment #28
I am concerned about outdoor burning each year from farming operations. The smoke generated prevents people (especially children) from enjoying the outdoors. It is a serious health concern. Instead of burning, I support farmers and others who normally burn, to use composting or burial methods instead.

DEQ Response
Please see DEQ Response to Comment 16.

Comment #29
Please. Do. your. job. Protect the air quality in Oregon and the Columbia Gorge to protect Oregonians' lives. Do NOT protect profits of polluters.

DEQ has excluded Three Mile Canyon Farms in Boardman, Oregon, from the plan. Why wasn't this miserable, monstrous cow factory included at the top of the list of facilities required to develop pollution control plans for round 2 of the Regional Haze Program?

Was there any outreach to communities directly affected by these polluters? Your draft plan appears to coddle and cuddle up to polluters while surrounding communities choke on their air pollution.

DEQ Response
Please see DEQ Response to Comments 10 and 14.

Comment #30
Shutting down the Boardman coal generating station has only minimally helped the Columbia Gorge haze problem.

DEQ Response
PGE's Boardman coal-fired facility shut down permanently in October 2020. Based on the 2017 National Emission Inventory for Morrow County, DEQ expects the Boardman shut down will eliminate more than 2,000 tons/year NOx, more than 3,000 tons/year SO2 and more than 400 tons/year PM10.

Comment #31
It is clear that DEQ is violating its own environmental justice guidelines with regard to "fair treatment and meaningful involvement of all people..." in drafting a regional haze plan that fails to meet the requirements of the Clean Air Act and the Regional Haze Rule.

The exclusions and allowances for polluters to continue and even increase polluting comes at the expense of all but those who profit from polluting and have a favored advantage at the table.

DEQ Response
Please see DEQ's response to Comments 22 and 26.

Appendix A. Q/d >= 5.00 facility list

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
05-1849	A Division of Cascades Holding US Inc.	OR	Mount Hood Wilderness	OR	87.68	265.03	5,587.00	3.02	63.72	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Mount Adams Wilderness	WA	98.41	265.03	5,587.00	2.69	56.77	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Goat Rocks Wilderness	WA	117.74	265.03	5,587.00	2.25	47.45	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Mount Rainier NP	WA	120.08	265.03	5,587.00	2.21	46.53	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Mount Jefferson Wilderness	OR	137.20	265.03	5,587.00	1.93	40.72	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Mount Washington Wilderness	OR	176.39	265.03	5,587.00	1.50	31.67	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Olympic NP	WA	188.26	265.03	5,587.00	1.41	29.68	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Three Sisters Wilderness	OR	191.45	265.03	5,587.00	1.38	29.18	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Alpine Lakes Wilderness	WA	198.98	265.03	5,587.00	1.33	28.08	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Diamond Peak Wilderness	OR	254.93	265.03	5,587.00	1.04	21.92	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Glacier Peak Wilderness	WA	264.96	265.03	5,587.00	1.00	21.09	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Crater Lake NP	OR	310.45	265.03	5,587.00	0.85	18.00	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	North Cascades NP	WA	315.61	265.03	5,587.00	0.84	17.70	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Strawberry Mountain Wilderness	OR	346.81	265.03	5,587.00	0.76	16.11	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Pasayten Wilderness	WA	349.02	265.03	5,587.00	0.76	16.01	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Mountain Lakes Wilderness	OR	387.79	265.03	5,587.00	0.68	14.41	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Kalmiopsis Wilderness	OR	388.39	265.03	5,587.00	0.68	14.38	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Gearhart Mountain Wilderness	OR	393.56	265.03	5,587.00	0.67	14.20	244.40	14.53	6.10	1,449.00	738.00	3,400.00
05-1849	A Division of Cascades Holding US Inc.	OR	Eagle Cap Wilderness	OR	397.96	265.03	5,587.00	0.67	14.04	244.40	14.53	6.10	1,449.00	738.00	3,400.00
128	Alcoa Primary Metals Intalco Works	WA	Mount Hood Wilderness	OR	386.45	4,776.22	0.00	12.36	0.00	190.17	598.71	3,987.34	0.00	0.00	0.00
01-0029	Ash Grove Cement Company	OR	Eagle Cap Wilderness	OR	51.88	961.92	1,996.00	18.54	38.47	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Hells Canyon Wilderness	ID-OR	76.63	961.92	1,996.00	12.55	26.05	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Strawberry Mountain Wilderness	OR	95.57	961.92	1,996.00	10.07	20.89	788.00	140.82	33.10	1,778.00	176.00	42.00

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
01-0029	Ash Grove Cement Company	OR	Sawtooth Wilderness	ID	181.25	961.92	1,996.00	5.31	11.01	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Selway-Bitterroot Wilderness	MT-ID	229.28	961.92	1,996.00	4.20	8.71	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Anaconda Pintler Wilderness	MT	320.60	961.92	1,996.00	3.00	6.23	788.00	140.82	33.10	1,778.00	176.00	42.00
11339	Ash Grove Cement Company	WA	Mount Hood Wilderness	OR	241.76	1,466.47	0.00	6.07	0.00	1,367.89	29.15	69.42	0.00	0.00	0.00
01-0029	Ash Grove Cement Company	OR	Craters of the Moon Wilderness	ID	330.35	961.92	1,996.00	2.91	6.04	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Three Sisters Wilderness	OR	336.77	961.92	1,996.00	2.86	5.93	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Mount Jefferson Wilderness	OR	337.20	961.92	1,996.00	2.85	5.92	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Jarbridge Wilderness	NV	337.29	961.92	1,996.00	2.85	5.92	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Mount Hood Wilderness	OR	341.69	961.92	1,996.00	2.82	5.84	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Mount Washington Wilderness	OR	346.80	961.92	1,996.00	2.77	5.76	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Gearhart Mountain Wilderness	OR	352.57	961.92	1,996.00	2.73	5.66	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Mount Adams Wilderness	WA	363.23	961.92	1,996.00	2.65	5.50	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Spokane Reservation	WA	364.30	961.92	1,996.00	2.64	5.48	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Flathead Reservation	MT	370.36	961.92	1,996.00	2.60	5.39	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Goat Rocks Wilderness	WA	372.31	961.92	1,996.00	2.58	5.36	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0029	Ash Grove Cement Company	OR	Diamond Peak Wilderness	OR	380.19	961.92	1,996.00	2.53	5.25	788.00	140.82	33.10	1,778.00	176.00	42.00
01-0038	Baker Compressor Station	OR	Eagle Cap Wilderness	OR	40.16	161.62	595.00	4.02	14.81	158.48	1.97	1.17	542.00	14.00	39.00
01-0038	Baker Compressor Station	OR	Strawberry Mountain Wilderness	OR	83.21	161.62	595.00	1.94	7.15	158.48	1.97	1.17	542.00	14.00	39.00
01-0038	Baker Compressor Station	OR	Hells Canyon Wilderness	ID-OR	85.62	161.62	595.00	1.89	6.95	158.48	1.97	1.17	542.00	14.00	39.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Mount Rainier NP	WA	114.86	431.25	4,612.00	3.75	40.15	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Mount Adams Wilderness	WA	119.66	431.25	4,612.00	3.60	38.54	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Goat Rocks Wilderness	WA	127.43	431.25	4,612.00	3.38	36.19	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Mount Hood Wilderness	OR	133.28	431.25	4,612.00	3.24	34.60	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Olympic NP	WA	147.97	431.25	4,612.00	2.91	31.17	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Mount Jefferson Wilderness	OR	183.56	431.25	4,612.00	2.35	25.13	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Alpine Lakes Wilderness	WA	185.04	431.25	4,612.00	2.33	24.92	359.22	62.19	9.85	3,776.00	241.00	595.00

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
05-2520	Beaver Plant/Port Westward I Plant	OR	Mount Washington Wilderness	OR	221.48	431.25	4,612.00	1.95	20.82	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Three Sisters Wilderness	OR	237.18	431.25	4,612.00	1.82	19.44	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Glacier Peak Wilderness	WA	250.45	431.25	4,612.00	1.72	18.41	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Diamond Peak Wilderness	OR	297.42	431.25	4,612.00	1.45	15.51	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	North Cascades NP	WA	297.50	431.25	4,612.00	1.45	15.50	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Pasayten Wilderness	WA	328.95	431.25	4,612.00	1.31	14.02	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Crater Lake NP	OR	351.86	431.25	4,612.00	1.23	13.11	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Strawberry Mountain Wilderness	OR	389.49	431.25	4,612.00	1.11	11.84	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Kalmiopsis Wilderness	OR	417.75	431.25	4,612.00	1.03	11.04	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Mountain Lakes Wilderness	OR	427.74	431.25	4,612.00	1.01	10.78	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Eagle Cap Wilderness	OR	428.90	431.25	4,612.00	1.01	10.75	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Gearhart Mountain Wilderness	OR	437.64	431.25	4,612.00	0.99	10.54	359.22	62.19	9.85	3,776.00	241.00	595.00
05-2520	Beaver Plant/Port Westward I Plant	OR	Hells Canyon Wilderness	ID-OR	500.40	431.25	4,612.00	0.86	9.22	359.22	62.19	9.85	3,776.00	241.00	595.00
15-0159	Biomass One, L.P.	OR	Mountain Lakes Wilderness	OR	56.41	268.89	556.00	4.77	9.86	239.00	15.57	14.32	469.00	48.00	39.00
15-0159	Biomass One, L.P.	OR	Crater Lake NP	OR	62.73	268.89	556.00	4.29	8.86	239.00	15.57	14.32	469.00	48.00	39.00
15-0159	Biomass One, L.P.	OR	Kalmiopsis Wilderness	OR	79.27	268.89	556.00	3.39	7.01	239.00	15.57	14.32	469.00	48.00	39.00
15-0159	Biomass One, L.P.	OR	Marble Mountain Wilderness	CA	87.83	268.89	556.00	3.06	6.33	239.00	15.57	14.32	469.00	48.00	39.00
15-0004	Boise Cascade- Medford	OR	Mountain Lakes Wilderness	OR	60.57	253.68	425.00	4.19	7.02	113.42	125.26	15.00	227.00	167.00	31.00
15-0004	Boise Cascade- Medford	OR	Crater Lake NP	OR	71.93	253.68	425.00	3.53	5.91	113.42	125.26	15.00	227.00	167.00	31.00
15-0004	Boise Cascade- Medford	OR	Kalmiopsis Wilderness	OR	75.12	253.68	425.00	3.38	5.66	113.42	125.26	15.00	227.00	167.00	31.00
15-0004	Boise Cascade- Medford	OR	Marble Mountain Wilderness	CA	78.01	253.68	425.00	3.25	5.45	113.42	125.26	15.00	227.00	167.00	31.00
127	Boise Paper	WA	Eagle Cap Wilderness	OR	114.04	1,656.24	0.00	14.52	0.00	637.27	133.56	885.41	0.00	0.00	0.00
127	Boise Paper	WA	Hells Canyon Wilderness	ID-OR	173.84	1,656.24	0.00	9.53	0.00	637.27	133.56	885.41	0.00	0.00	0.00
127	Boise Paper	WA	Strawberry Mountain Wilderness	OR	193.31	1,656.24	0.00	8.57	0.00	637.27	133.56	885.41	0.00	0.00	0.00
127	Boise Paper	WA	Mount Hood Wilderness	OR	221.76	1,656.24	0.00	7.47	0.00	637.27	133.56	885.41	0.00	0.00	0.00
127	Boise Paper	WA	Mount Jefferson Wilderness	OR	269.21	1,656.24	0.00	6.15	0.00	637.27	133.56	885.41	0.00	0.00	0.00
127	Boise Paper	WA	Mount Washington Wilderness	OR	297.07	1,656.24	0.00	5.58	0.00	637.27	133.56	885.41	0.00	0.00	0.00

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
127	Boise Paper	WA	Three Sisters Wilderness	OR	298.55	1,656.24	0.00	5.55	0.00	637.27	133.56	885.41	0.00	0.00	0.00
46	BP CHERRY POINT REFINERY	WA	Mount Hood Wilderness	OR	391.39	2,808.00	0.00	7.17	0.00	1,918.00	82.00	808.00	0.00	0.00	0.00
2175	Cardinal FG Winlock	WA	Mount Hood Wilderness	OR	151.89	881.83	0.00	5.81	0.00	809.14	16.47	56.22	0.00	0.00	0.00
06900001	CLEARWATER PAPER CORP - PPD & CPD	ID	Hells Canyon Wilderness	ID-OR	70.62	1,614.27	0.00	22.86	0.00	1,372.03	191.14	51.09	0.00	0.00	0.00
06900001	CLEARWATER PAPER CORP - PPD & CPD	ID	Eagle Cap Wilderness	OR	114.96	1,614.27	0.00	14.04	0.00	1,372.03	191.14	51.09	0.00	0.00	0.00
06900001	CLEARWATER PAPER CORP - PPD & CPD	ID	Strawberry Mountain Wilderness	OR	265.89	1,614.27	0.00	6.07	0.00	1,372.03	191.14	51.09	0.00	0.00	0.00
18-0013	Collins Products, L.L.C.	OR	Mountain Lakes Wilderness	OR	23.57	112.77	255.00	4.78	10.82	6.85	105.89	0.03	39.00	166.00	50.00
18-0013	Collins Products, L.L.C.	OR	Lava Beds/Schonchin Wilderness	CA	46.50	112.77	255.00	2.43	5.48	6.85	105.89	0.03	39.00	166.00	50.00
18-0013	Collins Products, L.L.C.	OR	Lava Beds/Black Lava Flow Wilderness	CA	47.51	112.77	255.00	2.37	5.37	6.85	105.89	0.03	39.00	166.00	50.00
18-0014	Columbia Forest Products, Inc.	OR	Mountain Lakes Wilderness	OR	24.64	101.08	191.00	4.10	7.75	43.19	57.16	0.73	65.00	87.00	39.00
09-0084	Compressor Station 12	OR	Three Sisters Wilderness	OR	30.44	70.78	430.00	2.33	14.13	63.60	4.62	2.56	377.00	14.00	39.00
09-0084	Compressor Station 12	OR	Diamond Peak Wilderness	OR	49.11	70.78	430.00	1.44	8.76	63.60	4.62	2.56	377.00	14.00	39.00
09-0084	Compressor Station 12	OR	Mount Washington Wilderness	OR	59.59	70.78	430.00	1.19	7.22	63.60	4.62	2.56	377.00	14.00	39.00
09-0084	Compressor Station 12	OR	Mount Jefferson Wilderness	OR	76.99	70.78	430.00	0.92	5.59	63.60	4.62	2.56	377.00	14.00	39.00
18-0006	dba JELD-WEN	OR	Mountain Lakes Wilderness	OR	21.11	44.95	133.00	2.13	6.30	26.59	16.78	1.58	67.00	27.00	39.00
31-0006	Elgin Complex	OR	Eagle Cap Wilderness	OR	18.09	182.26	272.00	10.08	15.04	128.15	41.10	13.01	171.00	62.00	39.00
26-1865	EVRAZ Inc. NA	OR	Mount Hood Wilderness	OR	73.15	261.41	872.00	3.57	11.92	139.40	118.74	3.27	493.00	340.00	39.00
26-1865	EVRAZ Inc. NA	OR	Mount Adams Wilderness	WA	107.17	261.41	872.00	2.44	8.14	139.40	118.74	3.27	493.00	340.00	39.00
26-1865	EVRAZ Inc. NA	OR	Mount Jefferson Wilderness	OR	116.05	261.41	872.00	2.25	7.51	139.40	118.74	3.27	493.00	340.00	39.00
26-1865	EVRAZ Inc. NA	OR	Goat Rocks Wilderness	WA	131.16	261.41	872.00	1.99	6.65	139.40	118.74	3.27	493.00	340.00	39.00
26-1865	EVRAZ Inc. NA	OR	Mount Rainier NP	WA	140.32	261.41	872.00	1.86	6.21	139.40	118.74	3.27	493.00	340.00	39.00
26-1865	EVRAZ Inc. NA	OR	Mount Washington Wilderness	OR	153.02	261.41	872.00	1.71	5.70	139.40	118.74	3.27	493.00	340.00	39.00
26-1865	EVRAZ Inc. NA	OR	Three Sisters Wilderness	OR	168.79	261.41	872.00	1.55	5.17	139.40	118.74	3.27	493.00	340.00	39.00
15-0135	Forever Friends Pet Cremation	OR	Mountain Lakes Wilderness	OR	5.36	0.00	92.00	0.00	17.16	0.00	0.00	0.00	39.00	14.00	39.00
18-0096	Gas Transmission NW - Compressor Station #13	OR	Crater Lake NP	OR	14.08	32.94	277.00	2.34	19.68	29.40	2.08	1.47	224.00	14.00	39.00
18-0096	Gas Transmission NW - Compressor Station #13	OR	Diamond Peak Wilderness	OR	46.81	32.94	277.00	0.70	5.92	29.40	2.08	1.47	224.00	14.00	39.00
04-0004	Georgia Pacific- Wauna Mill	OR	Mount Rainier NP	WA	131.17	2,353.29	4,129.00	17.94	31.48	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Mount Adams Wilderness	WA	137.45	2,353.29	4,129.00	17.12	30.04	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
04-0004	Georgia Pacific- Wauna Mill	OR	Goat Rocks Wilderness	WA	144.98	2,353.29	4,129.00	16.23	28.48	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Mount Hood Wilderness	OR	145.47	2,353.29	4,129.00	16.18	28.38	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Olympic NP	WA	148.68	2,353.29	4,129.00	15.83	27.77	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Mount Jefferson Wilderness	OR	192.35	2,353.29	4,129.00	12.23	21.47	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Alpine Lakes Wilderness	WA	198.75	2,353.29	4,129.00	11.84	20.77	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Mount Washington Wilderness	OR	227.76	2,353.29	4,129.00	10.33	18.13	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Three Sisters Wilderness	OR	244.30	2,353.29	4,129.00	9.63	16.90	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Glacier Peak Wilderness	WA	263.09	2,353.29	4,129.00	8.94	15.69	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Diamond Peak Wilderness	OR	300.72	2,353.29	4,129.00	7.83	13.73	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	North Cascades NP	WA	308.65	2,353.29	4,129.00	7.62	13.38	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Pasayten Wilderness	WA	340.01	2,353.29	4,129.00	6.92	12.14	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Crater Lake NP	OR	354.11	2,353.29	4,129.00	6.65	11.66	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Strawberry Mountain Wilderness	OR	404.30	2,353.29	4,129.00	5.82	10.21	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Kalmiopsis Wilderness	OR	413.46	2,353.29	4,129.00	5.69	9.99	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Mountain Lakes Wilderness	OR	430.41	2,353.29	4,129.00	5.47	9.59	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Gearhart Mountain Wilderness	OR	444.94	2,353.29	4,129.00	5.29	9.28	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Eagle Cap Wilderness	OR	447.91	2,353.29	4,129.00	5.25	9.22	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Hells Canyon Wilderness	ID-OR	519.72	2,353.29	4,129.00	4.53	7.94	1,037.66	775.80	539.82	2,139.00	1,077.00	913.00
120	Georgia-Pacific Consumer Operations LLC	WA	Mount Hood Wilderness	OR	45.45	689.00	0.00	15.16	0.00	486.00	163.00	40.00	0.00	0.00	0.00
120	Georgia-Pacific Consumer Operations LLC	WA	Mount Jefferson Wilderness	OR	96.44	689.00	0.00	7.14	0.00	486.00	163.00	40.00	0.00	0.00	0.00
21-0005	Georgia-Pacific- Toledo	OR	Three Sisters Wilderness	OR	147.04	1,150.94	2,989.00	7.83	20.33	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Mount Washington Wilderness	OR	157.92	1,150.94	2,989.00	7.29	18.93	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Mount Jefferson Wilderness	OR	158.20	1,150.94	2,989.00	7.28	18.89	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Mount Hood Wilderness	OR	177.98	1,150.94	2,989.00	6.47	16.79	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Diamond Peak Wilderness	OR	180.53	1,150.94	2,989.00	6.38	16.56	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Crater Lake NP	OR	217.65	1,150.94	2,989.00	5.29	13.73	939.11	195.76	16.07	1,351.00	799.00	839.00

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21-0005	Georgia-Pacific- Toledo	OR	Kalmiopsis Wilderness	OR	239.01	1,150.94	2,989.00	4.82	12.51	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Mount Adams Wilderness	WA	248.27	1,150.94	2,989.00	4.64	12.04	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Goat Rocks Wilderness	WA	274.89	1,150.94	2,989.00	4.19	10.87	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Mount Rainier NP	WA	283.59	1,150.94	2,989.00	4.06	10.54	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Mountain Lakes Wilderness	OR	285.39	1,150.94	2,989.00	4.03	10.47	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Redwood NP	CA	308.32	1,150.94	2,989.00	3.73	9.69	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Olympic NP	WA	317.62	1,150.94	2,989.00	3.62	9.41	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Marble Mountain Wilderness	CA	328.37	1,150.94	2,989.00	3.50	9.10	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Gearhart Mountain Wilderness	OR	333.66	1,150.94	2,989.00	3.45	8.96	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Alpine Lakes Wilderness	WA	362.12	1,150.94	2,989.00	3.18	8.25	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Lava Beds/Schonchin Wilderness	CA	367.03	1,150.94	2,989.00	3.14	8.14	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Lava Beds/Black Lava Flow Wilderness	CA	367.55	1,150.94	2,989.00	3.13	8.13	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Strawberry Mountain Wilderness	OR	398.98	1,150.94	2,989.00	2.88	7.49	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Eagle Cap Wilderness	OR	497.91	1,150.94	2,989.00	2.31	6.00	939.11	195.76	16.07	1,351.00	799.00	839.00
21-0005	Georgia-Pacific- Toledo	OR	Hells Canyon Wilderness	ID-OR	562.46	1,150.94	2,989.00	2.05	5.31	939.11	195.76	16.07	1,351.00	799.00	839.00
22-3501	Halsey Pulp Mill	OR	Three Sisters Wilderness	OR	80.37	711.79	1,904.00	8.86	23.69	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Mount Washington Wilderness	OR	93.56	711.79	1,904.00	7.61	20.35	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Mount Jefferson Wilderness	OR	96.77	711.79	1,904.00	7.36	19.68	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Diamond Peak Wilderness	OR	118.12	711.79	1,904.00	6.03	16.12	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Mount Hood Wilderness	OR	144.69	711.79	1,904.00	4.92	13.16	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Crater Lake NP	OR	162.43	711.79	1,904.00	4.38	11.72	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Kalmiopsis Wilderness	OR	224.18	711.79	1,904.00	3.18	8.49	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Mount Adams Wilderness	WA	228.78	711.79	1,904.00	3.11	8.32	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Mountain Lakes Wilderness	OR	235.68	711.79	1,904.00	3.02	8.08	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Goat Rocks Wilderness	WA	258.63	711.79	1,904.00	2.75	7.36	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Gearhart Mountain Wilderness	OR	271.53	711.79	1,904.00	2.62	7.01	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Mount Rainier NP	WA	279.04	711.79	1,904.00	2.55	6.82	352.06	278.81	80.92	687.00	366.00	851.00

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22-3501	Halsey Pulp Mill	OR	Redwood NP	CA	292.87	711.79	1,904.00	2.43	6.50	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Marble Mountain Wilderness	CA	298.49	711.79	1,904.00	2.38	6.38	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Lava Beds/Schonchin Wilderness	CA	314.47	711.79	1,904.00	2.26	6.05	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Lava Beds/Black Lava Flow Wilderness	CA	316.00	711.79	1,904.00	2.25	6.03	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Strawberry Mountain Wilderness	OR	336.99	711.79	1,904.00	2.11	5.65	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Olympic NP	WA	346.70	711.79	1,904.00	2.05	5.49	352.06	278.81	80.92	687.00	366.00	851.00
22-3501	Halsey Pulp Mill	OR	Alpine Lakes Wilderness	WA	359.71	711.79	1,904.00	1.98	5.29	352.06	278.81	80.92	687.00	366.00	851.00
18-0005	Interfor Gilchrist	OR	Diamond Peak Wilderness	OR	22.30	187.74	351.00	8.42	15.74	60.15	125.28	2.31	104.00	208.00	39.00
18-0005	Interfor Gilchrist	OR	Three Sisters Wilderness	OR	39.29	187.74	351.00	4.78	8.93	60.15	125.28	2.31	104.00	208.00	39.00
18-0005	Interfor Gilchrist	OR	Crater Lake NP	OR	50.36	187.74	351.00	3.73	6.97	60.15	125.28	2.31	104.00	208.00	39.00
208850	INTERNATIONAL PAPER	OR	Three Sisters Wilderness	OR	58.94	973.05	0.00	16.51	0.00	724.02	181.39	67.64	0.00	0.00	0.00
208850	INTERNATIONAL PAPER	OR	Diamond Peak Wilderness	OR	81.00	973.05	0.00	12.01	0.00	724.02	181.39	67.64	0.00	0.00	0.00
208850	INTERNATIONAL PAPER	OR	Mount Washington Wilderness	OR	81.85	973.05	0.00	11.89	0.00	724.02	181.39	67.64	0.00	0.00	0.00
208850	INTERNATIONAL PAPER	OR	Mount Jefferson Wilderness	OR	91.41	973.05	0.00	10.65	0.00	724.02	181.39	67.64	0.00	0.00	0.00
208850	INTERNATIONAL PAPER	OR	Crater Lake NP	OR	122.67	973.05	0.00	7.93	0.00	724.02	181.39	67.64	0.00	0.00	0.00
208850	INTERNATIONAL PAPER	OR	Mount Hood Wilderness	OR	164.50	973.05	0.00	5.92	0.00	724.02	181.39	67.64	0.00	0.00	0.00
09-9502	Joyfield Corporation	OR	Three Sisters Wilderness	OR	14.10	0.00	92.00	0.00	6.52	0.00	0.00	0.00	39.00	14.00	39.00
09-9502	Joyfield Corporation	OR	Mount Washington Wilderness	OR	17.14	0.00	92.00	0.00	5.37	0.00	0.00	0.00	39.00	14.00	39.00
204402	KINGSFORD MANUFACTURING COMPANY	OR	Three Sisters Wilderness	OR	60.86	510.81	0.00	8.39	0.00	289.12	177.59	44.10	0.00	0.00	0.00
204402	KINGSFORD MANUFACTURING COMPANY	OR	Diamond Peak Wilderness	OR	83.19	510.81	0.00	6.14	0.00	289.12	177.59	44.10	0.00	0.00	0.00
204402	KINGSFORD MANUFACTURING COMPANY	OR	Mount Washington Wilderness	OR	83.58	510.81	0.00	6.11	0.00	289.12	177.59	44.10	0.00	0.00	0.00
204402	KINGSFORD MANUFACTURING COMPANY	OR	Mount Jefferson Wilderness	OR	92.71	510.81	0.00	5.51	0.00	289.12	177.59	44.10	0.00	0.00	0.00
18-0003	Klamath Cogeneration Proj	OR	Mountain Lakes Wilderness	OR	24.45	168.96	401.00	6.91	16.40	143.00	19.56	6.40	314.00	48.00	39.00
18-0003	Klamath Cogeneration Proj	OR	Lava Beds/Schonchin Wilderness	CA	46.14	168.96	401.00	3.66	8.69	143.00	19.56	6.40	314.00	48.00	39.00
18-0003	Klamath Cogeneration Proj	OR	Lava Beds/Black Lava Flow Wilderness	CA	47.39	168.96	401.00	3.57	8.46	143.00	19.56	6.40	314.00	48.00	39.00
18-0003	Klamath Cogeneration Proj	OR	Crater Lake NP	OR	68.99	168.96	401.00	2.45	5.81	143.00	19.56	6.40	314.00	48.00	39.00
121	Longview Fibre Paper and Packaging, Inc. dba KapStone Kraft Paper Corporation	WA	Mount Hood Wilderness	OR	113.46	1,449.26	0.00	12.77	0.00	1,040.95	210.33	197.98	0.00	0.00	0.00
121	Longview Fibre Paper and Packaging, Inc. dba KapStone Kraft Paper Corporation	WA	Mount Jefferson Wilderness	OR	166.15	1,449.26	0.00	8.72	0.00	1,040.95	210.33	197.98	0.00	0.00	0.00

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121	Longview Fibre Paper and Packaging, Inc. dba KapStone Kraft Paper Corporation	WA	Mount Washington Wilderness	OR	206.12	1,449.26	0.00	7.03	0.00	1,040.95	210.33	197.98	0.00	0.00	0.00
121	Longview Fibre Paper and Packaging, Inc. dba KapStone Kraft Paper Corporation	WA	Three Sisters Wilderness	OR	220.95	1,449.26	0.00	6.56	0.00	1,040.95	210.33	197.98	0.00	0.00	0.00
121	Longview Fibre Paper and Packaging, Inc. dba KapStone Kraft Paper Corporation	WA	Diamond Peak Wilderness	OR	284.63	1,449.26	0.00	5.09	0.00	1,040.95	210.33	197.98	0.00	0.00	0.00
122	Nippon Dynawave Packaging Co.	WA	Mount Hood Wilderness	OR	118.70	2,463.94	0.00	20.76	0.00	1,949.43	124.30	390.21	0.00	0.00	0.00
122	Nippon Dynawave Packaging Co.	WA	Mount Jefferson Wilderness	OR	171.11	2,463.94	0.00	14.40	0.00	1,949.43	124.30	390.21	0.00	0.00	0.00
122	Nippon Dynawave Packaging Co.	WA	Mount Washington Wilderness	OR	210.78	2,463.94	0.00	11.69	0.00	1,949.43	124.30	390.21	0.00	0.00	0.00
122	Nippon Dynawave Packaging Co.	WA	Three Sisters Wilderness	OR	225.75	2,463.94	0.00	10.91	0.00	1,949.43	124.30	390.21	0.00	0.00	0.00
122	Nippon Dynawave Packaging Co.	WA	Diamond Peak Wilderness	OR	288.85	2,463.94	0.00	8.53	0.00	1,949.43	124.30	390.21	0.00	0.00	0.00
122	Nippon Dynawave Packaging Co.	WA	Crater Lake NP	OR	344.04	2,463.94	0.00	7.16	0.00	1,949.43	124.30	390.21	0.00	0.00	0.00
122	Nippon Dynawave Packaging Co.	WA	Strawberry Mountain Wilderness	OR	373.50	2,463.94	0.00	6.60	0.00	1,949.43	124.30	390.21	0.00	0.00	0.00
12-0032	Ochoco Lumber Company	OR	Strawberry Mountain Wilderness	OR	8.46	0.00	120.00	0.00	14.19	0.00	0.00	0.00	50.00	31.00	39.00
03-2729	Oregon City Compressor Station	OR	Mount Hood Wilderness	OR	43.82	159.40	591.00	3.64	13.49	156.66	1.72	1.02	536.00	16.00	39.00
03-2729	Oregon City Compressor Station	OR	Mount Jefferson Wilderness	OR	81.26	159.40	591.00	1.96	7.27	156.66	1.72	1.02	536.00	16.00	39.00
03-2729	Oregon City Compressor Station	OR	Mount Adams Wilderness	WA	106.80	159.40	591.00	1.49	5.53	156.66	1.72	1.02	536.00	16.00	39.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Mount Hood Wilderness	OR	55.05	597.87	1,156.00	10.86	21.00	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Mount Adams Wilderness	WA	97.54	597.87	1,156.00	6.13	11.85	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Mount Jefferson Wilderness	OR	100.59	597.87	1,156.00	5.94	11.49	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Goat Rocks Wilderness	WA	124.17	597.87	1,156.00	4.81	9.31	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Mount Rainier NP	WA	139.73	597.87	1,156.00	4.28	8.27	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Mount Washington Wilderness	OR	140.22	597.87	1,156.00	4.26	8.24	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Three Sisters Wilderness	OR	154.91	597.87	1,156.00	3.86	7.46	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Alpine Lakes Wilderness	WA	220.40	597.87	1,156.00	2.71	5.25	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Diamond Peak Wilderness	OR	220.45	597.87	1,156.00	2.71	5.24	403.65	76.15	118.07	711.00	132.00	313.00
26-1876	Owens-Brockway Glass Container Inc.	OR	Olympic NP	WA	223.32	597.87	1,156.00	2.68	5.18	403.65	76.15	118.07	711.00	132.00	313.00
08-0003	Pacific Wood Laminates, Inc.	OR	Kalmiopsis Wilderness	OR	23.52	194.89	294.00	8.29	12.50	52.50	139.12	3.27	76.00	189.00	29.00
08-0003	Pacific Wood Laminates, Inc.	OR	Redwood NP	CA	27.44	194.89	294.00	7.10	10.72	52.50	139.12	3.27	76.00	189.00	29.00
31-0002	Particleboard	OR	Eagle Cap Wilderness	OR	24.99	332.96	460.00	13.32	18.41	305.10	25.49	2.38	379.00	42.00	39.00
25-0016	PGE Boardman	OR	Mount Adams Wilderness	WA	137.66	5,453.74	16,572.00	39.62	120.38	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
25-0016	PGE Boardman	OR	Mount Hood Wilderness	OR	142.61	5,453.74	16,572.00	38.24	116.21	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Goat Rocks Wilderness	WA	145.09	5,453.74	16,572.00	37.59	114.22	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Strawberry Mountain Wilderness	OR	163.33	5,453.74	16,572.00	33.39	101.47	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Eagle Cap Wilderness	OR	164.42	5,453.74	16,572.00	33.17	100.79	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Mount Rainier NP	WA	174.24	5,453.74	16,572.00	31.30	95.11	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Mount Jefferson Wilderness	OR	186.47	5,453.74	16,572.00	29.25	88.87	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Alpine Lakes Wilderness	WA	205.90	5,453.74	16,572.00	26.49	80.49	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Mount Washington Wilderness	OR	215.09	5,453.74	16,572.00	25.36	77.05	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Three Sisters Wilderness	OR	216.94	5,453.74	16,572.00	25.14	76.39	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Hells Canyon Wilderness	ID-OR	240.57	5,453.74	16,572.00	22.67	68.89	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Glacier Peak Wilderness	WA	255.89	5,453.74	16,572.00	21.31	64.76	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Spokane Reservation	WA	268.73	5,453.74	16,572.00	20.29	61.67	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Diamond Peak Wilderness	OR	293.54	5,453.74	16,572.00	18.58	56.46	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	North Cascades NP	WA	307.96	5,453.74	16,572.00	17.71	53.81	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Olympic NP	WA	335.41	5,453.74	16,572.00	16.26	49.41	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Pasayten Wilderness	WA	336.23	5,453.74	16,572.00	16.22	49.29	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Crater Lake NP	OR	338.37	5,453.74	16,572.00	16.12	48.98	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Selway-Bitterroot Wilderness	MT-ID	347.23	5,453.74	16,572.00	15.71	47.73	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Gearhart Mountain Wilderness	OR	354.86	5,453.74	16,572.00	15.37	46.70	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Mountain Lakes Wilderness	OR	428.46	5,453.74	16,572.00	12.73	38.68	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
25-0016	PGE Boardman	OR	Kalmiopsis Wilderness	OR	504.68	5,453.74	16,572.00	10.81	32.84	1,768.12	387.75	3,297.87	5,961.00	1,086.00	9,525.00
---	Portland International Airport	OR	Mount Hood Wilderness	OR	60.28	1,806.21	0.00	29.96	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Mount Adams Wilderness	WA	98.57	1,806.21	0.00	18.32	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Mount Jefferson Wilderness	OR	105.81	1,806.21	0.00	17.07	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Goat Rocks Wilderness	WA	124.38	1,806.21	0.00	14.52	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Mount Rainier NP	WA	137.96	1,806.21	0.00	13.09	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
---	Portland International Airport	OR	Mount Washington Wilderness	OR	144.96	1,806.21	0.00	12.46	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Three Sisters Wilderness	OR	159.87	1,806.21	0.00	11.30	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Alpine Lakes Wilderness	WA	218.55	1,806.21	0.00	8.26	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Olympic NP	WA	218.87	1,806.21	0.00	8.25	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Diamond Peak Wilderness	OR	224.61	1,806.21	0.00	8.04	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Crater Lake NP	OR	280.60	1,806.21	0.00	6.44	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Glacier Peak Wilderness	WA	283.36	1,806.21	0.00	6.37	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Strawberry Mountain Wilderness	OR	321.71	1,806.21	0.00	5.61	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	North Cascades NP	WA	335.61	1,806.21	0.00	5.38	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
---	Portland International Airport	OR	Mountain Lakes Wilderness	OR	358.18	1,806.21	0.00	5.04	0.00	1,550.53	40.85	214.82	0.00	0.00	0.00
31-0008	R. D. Mac, Inc.	OR	Eagle Cap Wilderness	OR	27.26	0.00	184.00	0.00	6.75	0.00	0.00	0.00	78.00	28.00	78.00
10-0025	Roseburg Forest Products - Dillard	OR	Kalmiopsis Wilderness	OR	81.78	1,559.71	2,508.00	19.07	30.67	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Crater Lake NP	OR	91.38	1,559.71	2,508.00	17.07	27.44	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Diamond Peak Wilderness	OR	108.86	1,559.71	2,508.00	14.33	23.04	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Mountain Lakes Wilderness	OR	128.44	1,559.71	2,508.00	12.14	19.53	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Three Sisters Wilderness	OR	136.52	1,559.71	2,508.00	11.42	18.37	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Redwood NP	CA	150.14	1,559.71	2,508.00	10.39	16.70	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Marble Mountain Wilderness	CA	155.21	1,559.71	2,508.00	10.05	16.16	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Mount Washington Wilderness	OR	171.49	1,559.71	2,508.00	9.10	14.62	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Mount Jefferson Wilderness	OR	191.27	1,559.71	2,508.00	8.15	13.11	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Lava Beds/Black Lava Flow Wilderness	CA	208.51	1,559.71	2,508.00	7.48	12.03	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Lava Beds/Schonchin Wilderness	CA	210.07	1,559.71	2,508.00	7.42	11.94	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Gearhart Mountain Wilderness	OR	213.71	1,559.71	2,508.00	7.30	11.74	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Mount Hood Wilderness	OR	276.60	1,559.71	2,508.00	5.64	9.07	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Thousand Lakes Wilderness	CA	301.34	1,559.71	2,508.00	5.18	8.32	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	South Warner Wilderness	CA	318.14	1,559.71	2,508.00	4.90	7.88	1,006.94	479.24	73.52	1,655.00	743.00	110.00

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
10-0025	Roseburg Forest Products - Dillard	OR	Lassen Volcanic NP	CA	320.28	1,559.71	2,508.00	4.87	7.83	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Yolla Bolly-Middle Eel Wilderness	CA	321.08	1,559.71	2,508.00	4.86	7.81	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Caribou Wilderness	CA	332.88	1,559.71	2,508.00	4.69	7.53	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Mount Adams Wilderness	WA	366.33	1,559.71	2,508.00	4.26	6.85	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Strawberry Mountain Wilderness	OR	385.69	1,559.71	2,508.00	4.04	6.50	1,006.94	479.24	73.52	1,655.00	743.00	110.00
10-0025	Roseburg Forest Products - Dillard	OR	Goat Rocks Wilderness	WA	397.16	1,559.71	2,508.00	3.93	6.31	1,006.94	479.24	73.52	1,655.00	743.00	110.00
15-0073	Roseburg Forest Products- Medford MDF	OR	Mountain Lakes Wilderness	OR	59.50	173.33	526.00	2.91	8.84	131.16	36.24	5.94	272.00	215.00	39.00
15-0073	Roseburg Forest Products- Medford MDF	OR	Crater Lake NP	OR	71.80	173.33	526.00	2.41	7.33	131.16	36.24	5.94	272.00	215.00	39.00
15-0073	Roseburg Forest Products- Medford MDF	OR	Kalmiopsis Wilderness	OR	76.27	173.33	526.00	2.27	6.90	131.16	36.24	5.94	272.00	215.00	39.00
15-0073	Roseburg Forest Products- Medford MDF	OR	Marble Mountain Wilderness	CA	77.45	173.33	526.00	2.24	6.79	131.16	36.24	5.94	272.00	215.00	39.00
10-0078	Roseburg Forest Products- Riddle Plywood	OR	Kalmiopsis Wilderness	OR	68.95	144.78	365.00	2.10	5.29	79.49	50.16	15.13	199.00	127.00	39.00
---	Seattle-Tacoma Intl	WA	Mount Hood Wilderness	OR	226.99	4,286.64	0.00	18.88	0.00	3,704.20	76.43	506.01	0.00	0.00	0.00
---	Seattle-Tacoma Intl	WA	Mount Jefferson Wilderness	OR	294.45	4,286.64	0.00	14.56	0.00	3,704.20	76.43	506.01	0.00	0.00	0.00
---	Seattle-Tacoma Intl	WA	Mount Washington Wilderness	OR	341.53	4,286.64	0.00	12.55	0.00	3,704.20	76.43	506.01	0.00	0.00	0.00
---	Seattle-Tacoma Intl	WA	Three Sisters Wilderness	OR	351.62	4,286.64	0.00	12.19	0.00	3,704.20	76.43	506.01	0.00	0.00	0.00
10-0045	Swanson Group Mfg. LLC	OR	Kalmiopsis Wilderness	OR	48.81	202.99	312.00	4.16	6.39	55.24	144.76	2.99	80.00	193.00	39.00
2	TESORO NORTHWEST COMPANY	WA	Mount Hood Wilderness	OR	347.26	2,194.33	0.00	6.32	0.00	1,970.78	143.83	79.72	0.00	0.00	0.00
15-0025	Timber Products Co. Limited Partnership	OR	Mountain Lakes Wilderness	OR	59.35	96.82	360.00	1.63	6.07	69.18	25.21	2.43	162.00	159.00	39.00
754	TransAlta Centralia Generation, LLC	WA	Mount Hood Wilderness	OR	169.98	8,323.32	0.00	48.97	0.00	6,214.37	419.33	1,689.62	0.00	0.00	0.00
754	TransAlta Centralia Generation, LLC	WA	Mount Jefferson Wilderness	OR	230.03	8,323.32	0.00	36.18	0.00	6,214.37	419.33	1,689.62	0.00	0.00	0.00
754	TransAlta Centralia Generation, LLC	WA	Mount Washington Wilderness	OR	273.59	8,323.32	0.00	30.42	0.00	6,214.37	419.33	1,689.62	0.00	0.00	0.00
754	TransAlta Centralia Generation, LLC	WA	Three Sisters Wilderness	OR	286.66	8,323.32	0.00	29.04	0.00	6,214.37	419.33	1,689.62	0.00	0.00	0.00
754	TransAlta Centralia Generation, LLC	WA	Diamond Peak Wilderness	OR	354.92	8,323.32	0.00	23.45	0.00	6,214.37	419.33	1,689.62	0.00	0.00	0.00
AP49110457	VALMY COOLING TOWER #2	NV	Gearhart Mountain Wilderness	OR	348.95	2,858.07	0.00	8.19	0.00	1,218.79	51.01	1,588.27	0.00	0.00	0.00
AP49110457	VALMY COOLING TOWER #2	NV	Strawberry Mountain Wilderness	OR	391.79	2,858.07	0.00	7.29	0.00	1,218.79	51.01	1,588.27	0.00	0.00	0.00
03-2145	West Linn Paper Company	OR	Mount Hood Wilderness	OR	53.74	203.83	1,422.00	3.79	26.46	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Mount Jefferson Wilderness	OR	85.10	203.83	1,422.00	2.40	16.71	186.13	14.99	2.72	597.00	82.00	743.00

Agency Facility ID	Facility Name	Fac State	CIA Name	CIA State	Distance (km)	ActualComb Q (tpy)	PSELComb Q (tpy)	Q/d Actual	Q/d PSEL	NOX Actual	PM10-PRI Actual	SO2 Actual	NOX PSEL	PM10-PRI PSEL	SO2 PSEL
03-2145	West Linn Paper Company	OR	Mount Adams Wilderness	WA	116.25	203.83	1,422.00	1.75	12.23	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Mount Washington Wilderness	OR	120.50	203.83	1,422.00	1.69	11.80	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Three Sisters Wilderness	OR	136.48	203.83	1,422.00	1.49	10.42	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Goat Rocks Wilderness	WA	144.45	203.83	1,422.00	1.41	9.84	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Mount Rainier NP	WA	162.67	203.83	1,422.00	1.25	8.74	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Diamond Peak Wilderness	OR	198.50	203.83	1,422.00	1.03	7.16	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Alpine Lakes Wilderness	WA	243.34	203.83	1,422.00	0.84	5.84	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Olympic NP	WA	244.72	203.83	1,422.00	0.83	5.81	186.13	14.99	2.72	597.00	82.00	743.00
03-2145	West Linn Paper Company	OR	Crater Lake NP	OR	254.28	203.83	1,422.00	0.80	5.59	186.13	14.99	2.72	597.00	82.00	743.00
125	WestRock Tacoma Mill	WA	Mount Hood Wilderness	OR	210.43	1,532.36	0.00	7.28	0.00	1,120.90	221.74	189.72	0.00	0.00	0.00
125	WestRock Tacoma Mill	WA	Mount Jefferson Wilderness	OR	276.92	1,532.36	0.00	5.53	0.00	1,120.90	221.74	189.72	0.00	0.00	0.00

Appendix B. Oregon facilities with potential visibility impacts in other states

Row Labels	CIAName	Facility Name	Q/d Actual	Q/d PSEL
WA	**Alpine Lakes Wilderness**	A Division of Cascades Holding US Inc.	1.33	28.08
		Beaver Plant/Port Westward I Plant	2.33	24.92
		Georgia Pacific- Wauna Mill	11.84	20.77
		Georgia-Pacific- Toledo	3.18	8.25
		Halsey Pulp Mill	1.98	5.29
		Owens-Brockway Glass Container Inc.	2.71	5.25
		PGE Boardman	26.49	80.49
		Portland International Airport	8.26	0.00
		Willamette Falls Paper Company	0.84	5.84
	Glacier Peak Wilderness	A Division of Cascades Holding US Inc.	1.00	21.09
		Beaver Plant/Port Westward I Plant	1.72	18.41
		Georgia Pacific- Wauna Mill	8.94	15.69
		PGE Boardman	21.31	64.76
		Portland International Airport	6.37	0.00
	Goat Rocks Wilderness	A Division of Cascades Holding US Inc.	2.25	47.45
		Ash Grove Cement Company	2.58	5.36
		Beaver Plant/Port Westward I Plant	3.38	36.19
		EVRAZ Inc. NA	1.99	6.65
		Georgia Pacific- Wauna Mill	16.23	28.48
		Georgia-Pacific- Toledo	4.19	10.87
		Halsey Pulp Mill	2.75	7.36
		Owens-Brockway Glass Container Inc.	4.81	9.31
		PGE Boardman	37.59	114.22
		Portland International Airport	14.52	0.00
		Roseburg Forest Products - Dillard	3.93	6.31

Row Labels	CIAName	Facility Name	Q/d Actual	Q/d PSEL
		Willamette Falls Paper Company	1.41	9.84
	Mount Adams Wilderness	A Division of Cascades Holding US Inc.	2.69	56.77
		Ash Grove Cement Company	2.65	5.50
		Beaver Plant/Port Westward I Plant	3.60	38.54
		EVRAZ Inc. NA	2.44	8.14
		Georgia Pacific- Wauna Mill	17.12	30.04
		Georgia-Pacific- Toledo	4.64	12.04
		Halsey Pulp Mill	3.11	8.32
		Oregon City Compressor Station	1.49	5.53
		Owens-Brockway Glass Container Inc.	6.13	11.85
		PGE Boardman	39.62	120.38
		Portland International Airport	18.32	0.00
		Roseburg Forest Products - Dillard	4.26	6.85
		Willamette Falls Paper Company	1.75	12.23
	Mount Rainier NP	A Division of Cascades Holding US Inc.	2.21	46.53
		Beaver Plant/Port Westward I Plant	3.75	40.15
		EVRAZ Inc. NA	1.86	6.21
		Georgia Pacific- Wauna Mill	17.94	31.48
		Georgia-Pacific- Toledo	4.06	10.54
		Halsey Pulp Mill	2.55	6.82
		Owens-Brockway Glass Container Inc.	4.28	8.27
		PGE Boardman	31.30	95.11
		Portland International Airport	13.09	0.00
		Willamette Falls Paper Company	1.25	8.74
	North Cascades NP	A Division of Cascades Holding US Inc.	0.84	17.70
		Beaver Plant/Port Westward I Plant	1.45	15.50
		Georgia Pacific- Wauna Mill	7.62	13.38
		PGE Boardman	17.71	53.81
		Portland International Airport	5.38	0.00
	Olympic NP	A Division of Cascades Holding US Inc.	1.41	29.68
		Beaver Plant/Port Westward I Plant	2.91	31.17

Row Labels	CIAName	Facility Name	Q/d Actual	Q/d PSEL
		Georgia Pacific- Wauna Mill	15.83	27.77
		Georgia-Pacific- Toledo	3.62	9.41
		Halsey Pulp Mill	2.05	5.49
		Owens-Brockway Glass Container Inc.	2.68	5.18
		PGE Boardman	16.26	49.41
		Portland International Airport	8.25	0.00
		Willamette Falls Paper Company	0.83	5.81
	Pasayten Wilderness	A Division of Cascades Holding US Inc.	0.76	16.01
		Beaver Plant/Port Westward I Plant	1.31	14.02
		Georgia Pacific- Wauna Mill	6.92	12.14
		PGE Boardman	16.22	49.29
	Spokane Reservation	Ash Grove Cement Company	2.64	5.48
		PGE Boardman	20.29	61.67
NV	**Jarbridge Wilderness**	Ash Grove Cement Company	2.85	5.92
MT-ID	**Selway-Bitterroot Wilderness**	Ash Grove Cement Company	4.20	8.71
		PGE Boardman	15.71	47.73
MT	**Anaconda Pintler Wilderness**	Ash Grove Cement Company	3.00	6.23
	Flathead Reservation	Ash Grove Cement Company	2.60	5.39
ID	**Craters of the Moon Wilderness**	Ash Grove Cement Company	2.91	6.04
	Sawtooth Wilderness	Ash Grove Cement Company	5.31	11.01
CA	**Caribou Wilderness**	Roseburg Forest Products - Dillard	4.69	7.53
	Lassen Volcanic NP	Roseburg Forest Products - Dillard	4.87	7.83
	Lava Beds/Black Lava Flow Wilderness	Collins Products, L.L.C.	2.37	5.37
		Georgia-Pacific- Toledo	3.13	8.13
		Halsey Pulp Mill	2.25	6.03
		Klamath Cogeneration Proj	3.57	8.46
		Roseburg Forest Products - Dillard	7.48	12.03
	Lava Beds/Schonchin Wilderness	Collins Products, L.L.C.	2.43	5.48
		Georgia-Pacific- Toledo	3.14	8.14
		Halsey Pulp Mill	2.26	6.05
		Klamath Cogeneration Proj	3.66	8.69

Row Labels	CIAName	Facility Name	Q/d Actual	Q/d PSEL
		Roseburg Forest Products - Dillard	7.42	11.94
	Marble Mountain Wilderness	Biomass One, L.P.	3.06	6.33
		Boise Cascade- Medford	3.25	5.45
		Georgia-Pacific- Toledo	3.50	9.10
		Halsey Pulp Mill	2.38	6.38
		Roseburg Forest Products - Dillard	10.05	16.16
		Roseburg Forest Products- Medford MDF	2.24	6.79
	Redwood NP	Georgia-Pacific- Toledo	3.73	9.69
		Halsey Pulp Mill	2.43	6.50
		Pacific Wood Laminates, Inc.	7.10	10.72
		Roseburg Forest Products - Dillard	10.39	16.70
	South Warner Wilderness	Roseburg Forest Products - Dillard	4.90	7.88
	Thousand Lakes Wilderness	Roseburg Forest Products - Dillard	5.18	8.32
	Yolla Bolly-Middle Eel Wilderness	Roseburg Forest Products - Dillard	4.86	7.81

Appendix C. Comparisons of data used to calculate environmental justice “scores”

This table is taken from Driver et al (2019) and adapted to include Washington’s model, and the data used in the current “run” of the environmental justice score.

Indicators	Description	EPA EJSCREEN	Cal EnviroScreen	MD EJSCREEN	WA Env Health Disp Map	OR EJSCREEN (in progress)
Pollution Burden: Exposure						
National Scale Air Toxics Air (NATA) Toxics Cancer Risk	Lifetime risk of developing cancer from inhalation of air toxins. Reported as risk per lifetime per million people [36].	X		X		
NATA Respiratory Hazard Index	Air toxics respiratory hazard index. This is the sum of hazard indices for those air toxics with reference concentrations based on respiratory endpoints, where each hazard index is the ratio of exposure concentration in the air to the health-based reference [36].	X		X		
NATA Diesel Particulate Matter (DPM)	Levels of diesel particulate matter in air. Reported as micrograms per cubic meter (µg/m^3) [35,36].	X	X	X	X	X
Particulate Matter ($PM_{2.5}$)	Levels of particulate matter with a diameter of 2.5 micrometers or smaller in air. Reported as micrograms per cubic meter (µg/m^3) [35,36].	X	X	X	X	X
Ozone	Summer seasonal average of the maximum daily 8-hour concentration of ozone in air in parts per billion [35,36].	X	X	X	X	X
Traffic Proximity and Volume	Count of vehicles (average annual daily traffic) at major roads within 500 meters or close to 500 meters, divided by distance in meters [35,36].	X	X	X	X	X
Pesticide Use	Total pounds of selected active pesticide ingredients (filtered for hazard and volatility) used in production-agriculture per square mile, averaged over three years (2012 to 2014) [36].		X			

Indicators	Description	EPA EJSCREEN	Cal EnviroScreen	MD EJSCREEN	WA Env Health Disp Map	OR EJSCREEN (in progress)
Drinking Water Contaminants	Water tested to contain one or more contaminants listed in 'Update to California Communities Environmental Health Screening Tool'. Reported as yearly averages of chemical contaminant concentrations for each census tract [36].		X			
Toxic Releases from Facilities	Toxicity-weighted concentrations of modeled chemical releases to air from facility emissions and off-site incineration (averaged over 2011 to 2013) [36].		X		X	?
Pollution Burden: Environmental Effects						
Lead Paint Indicator	Percent of houses built before 1960, which likely contain lead paint [36].	X		X	X	X
Proximity to Risk Management Plan (RMP) Sites	Count of RMP (potential chemical accident management plans) facilities within 5 kilometers or close to 5 kilometers, divided by distance in kilometers [36].	X		X	X	X
Proximity to Treatment Storage and Disposal Facilities (TSDF)	Count of TSDF (hazardous waste management facilities) within 5 kilometers or closest to 5 kilometers, divided by distance in kilometers [36].	X		X	X	X
Proximity to National Priorities List (NPL) Sites	Count of NPL/Superfund sites (polluted sites that pose a risk to human health and/or the environment) within 5 kilometers or close to 5 kilometers, divided by distance in kilometers [35,36].	X	X	X	X	X
Proximity to Major Direct Water Discharges	Toxic concentrations in stream segments within 500 meters, divided by distance in kilometers (km). Standards modeled after Risk-Screening Environmental Indicators (RSEI) [36].	X		X	X	X
Watershed Failure	Percent of each census tract's watershed that exceeds levels of phosphorus and/or nitrogen [39].			X		
Groundwater Threat	Nature and the magnitude of the threat and burden to groundwater safety posed by sites maintained in GeoTracker [35].		X			
Impaired Water Bodies	Contamination of streams, rivers, and lakes by pollutants which compromise the ability to use a body of water for drinking, swimming, fishing, aquatic life protection, etc. [35].		X			

Indicators	Description	EPA EJSCREEN	Cal EnviroScreen	MD EJSCREEN	WA Env Health Disp Map	OR EJSCREEN (in progress)
Solid Waste Sites and Facilities	Solid waste landfills, composting, and recycling facilities [35].		X			
Population Characteristics: Sensitive Populations						
Asthma Emergency Discharges	Count of patients released from the hospital after being admitted for asthma or asthma-related distress [40].			X		
Myocardial Infarction Discharges	Patients released from the hospital after being admitted for a heart attack or heart attack symptoms [35].		X	X		
Low Birth Weight Infants	Babies born weighing less than 5.5 pounds [35].		X	X	X	
Asthma Emergency Visits	Patients admitted to the emergency room for asthma or asthma-related distress [35].		X			
Cardiovascular disease					X	
Population Characteristics: Socioeconomic Factors						
Percent Non-White	Percentage of individuals who define themselves as any race/ethnicity besides non-Hispanic White [35,36].	X	X	X	X	X
Percent Low-Income	Percentage of individuals whose household income in the past 12 months is less than two times below the federal poverty level [35,36].	X	X	X	X	X
Less than high school education	Percentage of individuals 25 and older who lack a high school diploma [35,36].	X	X	X	X	X
Linguistic Isolation	Percentage of households in which no one 14 years old and older speaks English "very well", or households which speak only English [35,36].	X	X	X	X	X
Individuals under age 5	Percentage of people under the age of 5 [36].	X		X		?
Individuals over age 64	Percentage of people over the age of 64 [36].	X		X		?
Unemployment	Percentage of the population over the age of 16 that is unemployed and eligible for the labor force. Excludes retirees, students, homemakers, institutionalized persons except prisoners, those not looking for work, and military personnel on active duty [35].		X	X	X	

Indicators	Description	EPA EJSCREEN	Cal EnviroScreen	MD EJSCREEN	WA Env Health Disp Map	OR EJSCREEN (in progress)
Housing Burdened Low Income Households	Percentage of households in a census tract that make less than 80% of the HUD Area Median Family Income and paying greater than 50% of their income to finance housing [35].		X			
Transportation Expense					X	

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07/26/2021 1:14 PM
ARCHIVES DIVISION
SECRETARY OF STATE
& LEGISLATIVE COUNSEL

DEQ 14-2021

CHAPTER 340
DEPARTMENT OF ENVIRONMENTAL QUALITY

FILING CAPTION: Regional Haze 2021 Division 223

EFFECTIVE DATE: 07/26/2021

AGENCY APPROVED DATE: 07/23/2021

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RULES:
340-200-0040, 340-223-0010, 340-223-0020, 340-223-0030, 340-223-0040, 340-223-0050, 340-223-0060, 340-223-0070, 340-223-0080, 340-223-0100, 340-223-0110, 340-223-0120, 340-223-0130

AMEND: 340-200-0040

RULE TITLE: State of Oregon Clean Air Act Implementation Plan

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Amending rule to reflect adoption of rules that will amend Oregon's State Implementation Plan.

RULE TEXT:

(1) This implementation plan, consisting of Volumes 2 and 3 of the State of Oregon Air Quality Control Program, contains control strategies, rules and standards prepared by DEQ and is adopted as the State Implementation Plan (SIP) of the State of Oregon under the FCAA, 42 U.S.C.A 7401 to 7671q.

(2) Except as provided in section (3), revisions to the SIP will be made under the EQC’s rulemaking procedures in OAR 340 division 11 of this chapter and any other requirements contained in the SIP and will be submitted to the EPA for approval. The SIP was last modified by the EQC on July 23, 2021.

(3) Notwithstanding any other requirement contained in the SIP, DEQ may:

(a) Submit to the EPA any permit condition implementing a rule that is part of the federally-approved SIP as a source-specific SIP revision after DEQ has complied with the public hearings provisions of 40 C.F.R. 51.102; and

(b) Approve the standards submitted by LRAPA if LRAPA adopts verbatim, other than non-substantive differences, any standard that the EQC has adopted, and submit the standards to EPA for approval as a SIP revision.

(4) Revisions to the State of Oregon Clean Air Act Implementation Plan become federally enforceable upon approval by the EPA. If any provision of the federally approved State Implementation Plan conflicts with any provision adopted by the EQC, DEQ must enforce the more stringent provision.

STATUTORY/OTHER AUTHORITY: ORS 468A, ORS 468.020

STATUTES/OTHER IMPLEMENTED: ORS 468A.035, 468A.135

AMEND: 340-223-0010

RULE TITLE: Purpose

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Updating purpose statement. Updating CFR citation. Adding SIP note.

RULE TEXT:

OAR 340-223-0020 through 340-223-0130 establish the process and criteria for identifying reductions of pollutants from stationary sources that reduce visibility and contribute to regional haze in Class I areas, for the purpose of maintaining reasonable progress and other requirements associated with Oregon's implementation of the federal regional haze rule in 40 CFR 51.308 (2017).

[NOTE: This rule is included in the State of Oregon Clean Air Act Implementation Plan that EQC adopted under OAR 340-200-0040.]

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

AMEND: 340-223-0020

RULE TITLE: Definitions

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Removing definitions no longer used and adding three new definitions. Adding SIP note to rule.

RULE TEXT:

The definitions in OAR 340-200-0020 and this rule apply to this division. If the same term is defined in this rule and OAR 340-200-0020, the definition in this rule takes precedence.

(1) "Emissions unit" means any part or activity of a source that emits or has the potential to emit more than 20 tons of any single or combination of round II regional haze pollutants.

(2) “Round II regional haze pollutants” means the pollutants DEQ has identified in round II of regional haze that contribute to visibility impacts in Class I areas, which are sulfur dioxide, particulate matter of a nominal diameter of 10 microns or less, and nitrogen oxides.

(3) “Round II of regional haze” means the combination of information collection, technical demonstrations, control strategies, commitments, rules, orders, and any other actions that make up DEQ’s development and implementation of the 2018 through 2028 long-term strategy for reducing haze in Oregon’s Class I areas that will be submitted or that have been submitted to EPA as part of the state implementation plan.

[NOTE: This rule is included in the State of Oregon Clean Air Act Implementation Plan that EQC adopted under OAR 340-200-0040.]

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

REPEAL: 340-223-0030

RULE TITLE: BART Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106)

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Repealing rule because Boardman Coal Fired Power Plant has been decommissioned.

RULE TEXT:

(1) Emissions limits:

(a) Between July 1, 2011 and December 31, 2020, nitrogen oxide emissions must not exceed 0.23 lb/mmBtu heat input as a 30-day rolling average, provided that:

(A) If the source submitted a complete application for construction and/or operation of pollution control equipment to satisfy the emissions limit in subsection (1)(a) at least eight months prior to the compliance date of July 1, 2011, and the Department has not approved or denied the application by the compliance date, the compliance date is extended until the Department approves or disapproves the application, but may not be extended to a date more than five years from the date that the United States Environmental Protection Agency approves a revision to the State of Oregon Clean Air Act Implementation Plan that incorporates OAR 340-223-0030; and

(B) If it is demonstrated by December 31, 2011 that the emissions limit in subsection (1)(a) cannot be achieved with combustion controls, the Department by order may grant an extension of compliance to July 1, 2013.

(b) Except as provided in section (3) below:

(A) Between July 1, 2014 and June 30, 2018, sulfur dioxide emissions must not exceed 0.40 lb/mmBtu heat input as a 30-day rolling average; and

(B) Between July 1, 2018 and December 31, 2020, sulfur dioxide emissions must not exceed 0.30 lb/mmBtu heat input as a 30-day rolling average.

(c) Between July 1, 2014 and December 31, 2020, particulate matter emissions must not exceed 0.040 lb/mmBtu heat input as determined by compliance source testing.

(d) During periods of startup and shutdown, the following emissions limits apply instead of the limits in subsections (a) through (c):

(A) Sulfur dioxide emissions must not exceed 1.20 lb/mmBtu, as a 3-hour rolling average;

(B) Nitrogen oxide emissions must not exceed 0.70 lb/mmBtu, as a 3-hour rolling average; and

(C) Particulate matter emissions must be minimized to extent practicable pursuant to approved startup and shutdown procedures in accordance with OAR 340-214-0310.

(e) The Foster-Wheeler boiler at the source must permanently cease burning coal by no later than December 31, 2020. Notwithstanding the definition of netting basis in OAR 340-200-0020, and the process for reducing plant site emission limits in OAR 340-222-0043, the netting basis and PSELs for the boiler are reduced to zero upon the date on which the boiler permanently ceases burning coal, and prior to that date the netting basis and PSELs for the boiler apply only to physical changes or changes in the method of operation of the source for the purpose of complying with emission limits applicable to the boiler.

(2) Studies to evaluate compliance with the sulfur dioxide emissions limits in paragraphs (1)(b)(A)–(B), and the potential side effects of compliance with those limits, if required by section (3), must be completed as follows:

(a) A plan to evaluate the sulfur dioxide emissions limit in paragraph (1)(b)(A) must be submitted for Department approval by July 1, 2011, and the results of the evaluation must be submitted to the Department by July 1, 2013;

(b) A plan to evaluate the sulfur dioxide emissions limit in paragraph (1)(b)(B) must be submitted for Department approval by July 1, 2015, and the results of the evaluation must be submitted to the Department by July 1, 2017; and

(c) Each study pursuant to this section (2) must:

(A) Evaluate whether a dry sorbent injection pollution control system is technically infeasible, will prevent compliance with mercury emissions limits under OAR 340-228-0606, or cause a significant air quality impact (as that term is defined in 340-200-0020) for PM10 or PM2.5;

(B) Evaluate a range of commercially available sorbent materials that could be used in a dry sorbent injection pollution control system to reduce sulfur dioxide emissions;
(C) Evaluate the potential for significant air quality impacts for PM10 or PM2.5 as follows:
(i) Perform modeling consistent with the requirements of OAR 340-225-0050(1) with screening meteorological data containing conservative meteorological assumptions; or
(ii) If modeling with screening meteorological data pursuant to subparagraph (i) demonstrates that significant air quality impacts for PM10 or PM2.5 will occur, perform modeling with site specific meteorological data obtained from the installation of a meteorological monitoring station, including one year of monitoring data for each study. The meteorological monitoring station must be installed, certified, operated and maintained, and the output of the meteorological monitoring station must be recorded, in accordance with a plan approved by the Department;
(D) Evaluate the use of other sulfur dioxide pollution control systems of equal or lower cost as a dry sorbent injection pollution control system, including but not limited to the use of ultra-low sulfur coal, if the study demonstrates that the use of a dry sorbent injection pollution control system is technically infeasible, will prevent compliance with mercury emissions limits under OAR 340-228-0606, or will cause a significant air quality impact (as that term is defined in OAR 340-200-0020) for PM10 or PM2.5; and
(E) If applicable, propose an emissions limit for sulfur dioxide based on a 30-day rolling average that exceeds the limits listed in paragraphs (1)(b)(A)–(B), based upon the reduction of sulfur dioxide emissions to the maximum extent feasible through the use of a dry sorbent injection pollution control system or another sulfur dioxide pollution control system of equal or lower cost, including but not limited to the use of ultra-low sulfur coal, provided that the emissions limit may not exceed 0.55 lb/mmBtu heat input as a 30-day rolling average.
(3) Between July 1, 2014 and December 31, 2020, sulfur dioxide emissions may exceed the limit listed in paragraph (1)(b)(A) or (B), or both, if:
(a) Studies have been submitted pursuant to section (2);
(b) Compliance with the applicable emissions limit or limits would:
(A) Be technically infeasible;
(B) Prevent compliance with mercury emissions limits under OAR 340-228-0606; or
(C) Cause a significant air quality impact, as that term is defined in OAR 340-200-0020, for PM10 or PM2.5;
(c) Sulfur dioxide emissions are otherwise reduced to the maximum extent feasible as described in subsection (2)(c); and
(d) The source's Oregon Title V Operating Permit is modified to include a federally enforceable permit limit reflecting the requirements of subsection (2)(c), prior to the compliance date for the sulfur dioxide emissions limit in paragraph (1)(b)(A) or (B) that will be exceeded; provided that if the source's Oregon Title V Operating Permit has not been modified prior to the applicable compliance date, sulfur dioxide emissions may exceed the emissions limit in paragraph (1)(b)(A) or (B) if the source submitted a complete application to modify its Oregon Title V Operating Permit at least eight months prior to the applicable compliance date and sulfur dioxide emissions do not exceed the emissions limit proposed in its application (which may not exceed 0.55 lb/mmBtu heat input as a 30-day rolling average).
(4) Compliance demonstration. Using the procedures specified in section (5) of this rule:
(a) Compliance with a 30-day rolling average limit must be demonstrated within 180 days of the compliance date specified in section (1) of this rule; and
(b) Compliance with any 30-day rolling average limit for sulfur dioxide that may be established pursuant to subsection (3)(c) must be demonstrated within 180 days of the compliance date for the limit in paragraph (1)(b)(A) or (B) that is superseded by the emissions limit established pursuant to subsection (3)(c).
(5) Compliance Monitoring and Testing.
(a) Compliance with the emissions limits in subsections (1)(a), (b) and (d)(A)–(B), and with any emissions limit for sulfur dioxide that may be established pursuant to subsection (3)(c), must be determined with a continuous emissions monitoring system (CEMS) installed, operated, calibrated, and maintained in accordance with the acid rain monitoring requirements in 40 CFR Part 75 as in effect on December 9, 2010.
(A) The hourly emissions rate in terms of lb/mmBtu heat input must be recorded each operating hour, including periods

of startup and shutdown.
(B) The daily average emissions rate must be determined for each boiler operating day using the hourly emissions rates recorded in (A), excluding periods of startup and shutdown.
(C) 30-day rolling averages must be determined using all daily average emissions rates recorded in (B) whether or not the days are consecutive.
(D) The daily average emission rate is calculated for any calendar day in which the boiler combusts any fuel. An operating hour means a clock hour during which the boiler combusts any fuel, either for part of the hour or for the entire hour.
(b) Compliance with the particulate matter emissions limit in subsection (1)(c) must be determined by EPA Methods 5 and 19 as in effect on December 9, 2010.
(A) An initial particulate matter source test must be conducted by January 1, 2015.
(B) Subsequent tests must be conducted in accordance with a schedule specified in the source's Oregon Title V Operating Permit, but not less than once every 5 years.
(C) All testing must be performed in accordance with the Department's Source Sampling Manual as in effect on December 9, 2010. [NOTE: DEQ manuals are published with OAR 340-200-0035.]
(6) Notifications and Reports.
(a) The Department must be notified in writing within 7 days after any control equipment (including combustion controls) used to comply with emissions limits in section (1), and with any emissions limit for sulfur dioxide that may be established pursuant to subsection (3)(c), begins operation.
(b) For nitrogen oxide and sulfur dioxide emissions limits in section (1) based on a 30-day rolling average, a compliance status report, including CEMS data, must be submitted within 180 days of the compliance dates specified in section (1).
(c) For any sulfur dioxide emissions limit that may be established pursuant to subsection (3)(c), a compliance status report, including CEMS data, must be submitted within 180 days of the compliance date for the limit in paragraph (1)(b)(A) or (B) that is superseded by the emissions limit established pursuant to subsection (3)(c).
(d) For particulate matter, a compliance status report, including a source test report, must be submitted within 60 days of completing the initial compliance test and all subsequent tests as specified in subsection (5)(b).
(e) The Department must be notified in writing within 7 days of the date upon which the boiler permanently ceases burning coal.
(7) The following provisions of this rule constitute BART requirements for the Foster-Wheeler Boiler: subsection (1)(a), paragraph (1)(b)(A), subsections (1)(c)–(e), (2)(a) and (2)(c), and sections (3)–(6).
(8) The following provisions of this rule constitute additional requirements pursuant to the federal Regional Haze Rules under 40 CFR § 51.308(e) for the Foster-Wheeler Boiler: paragraph (1)(b)(B), subsections (2)(b) and (2)(c), and sections (3)–(6).
[NOTE: View a PDF of EPA Methods by clicking on "Tables" link below.]

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

REPEAL: 340-223-0040

RULE TITLE: Federally Enforceable Permit Limits

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Repealing rule because the Boardman Coal Fired Power Plant has been decommissioned.

RULE TEXT:

(1) A BART-eligible source that would be subject to BART may accept a federally enforceable permit limit or limits that reduces the source's emissions and prevents the source from being subject to BART.

(2) Any BART-eligible source that accepts a federally enforceable permit limit or limits as described in section (1) to prevent the source from being subject to BART, and that subsequently proposes to terminate its federally enforceable permit limit or limits, and that as a result will increase its emissions and become subject to BART, must submit a BART analysis to the Department and install BART as determined by the Department prior to terminating the federally enforceable permit limit or limits.

(3) The Foster-Wheeler boiler at The Amalgamated Sugar Company plant in Nyssa, Oregon (Title V permit number 23-0002) is a BART-eligible source, and air quality dispersion modeling demonstrates that it would be subject to BART while operating. However, it is not operating as of December 9, 2010, and therefore is not subject to BART. Prior to resuming operation, the owner or operator of the source must either:

(a) Submit a BART analysis and install BART as determined by the Department by no later than five years from the date that the United States Environmental Protection Agency approves a revision to the State of Oregon Clean Air Act Implementation Plan that incorporates OAR chapter 340, division 223, or before resuming operation, whichever is later; or

(b) Obtain and comply with a federally enforceable permit limit or limits assuring that the source's emissions will not cause the source to be subject to BART.

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

REPEAL: 340-223-0050

RULE TITLE: Alternative Regional Haze Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106)

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Repealing rule because the Boardman Coal Fired Power Plant has been decommissioned.

RULE TEXT:

(1) The owner and operator of the Foster-Wheeler boiler at the Boardman coal-fired power plant may elect to comply with OAR 340-223-0060 and 340-223-0070, or with 340-223-0080, in lieu of complying with OAR 340-223-0030, if the owner or operator provides written notification to the Director by no later than July 1, 2014. The written notification must identify which rule of the two alternatives the owner or operator has chosen to comply with. The owner or operator may not change its chosen method of compliance after July 1, 2014.

(2) Compliance with OAR 340-223-0080 in lieu of complying with 340-223-0030 is allowed only if the Foster-Wheeler boiler at the Boardman coal-fired power plant permanently ceases to burn coal within five years of the approval by the United States Environmental Protection Agency (EPA) of the revision to the State of Oregon Clean Air Act Implementation Plan that incorporates OAR chapter 340, division 223. If the boiler has not permanently ceased burning coal by that date, the owner and operator shall be liable for violating OAR 340-223-0030 for each day beginning July 1, 2014 on which the owner or operator did not comply with OAR 340-223-0030. This liability shall include, but is not limited to, civil penalties pursuant to OAR chapter 340, division 12, which includes penalties for the economic benefit of operating the facility without the required pollution controls.

(3) If, by December 31, 2011, the EPA fails to approve a revision to the State of Oregon Clean Air Act Implementation Plan that incorporates OAR 340-223-0030 (concerning BART requirements based upon permanently ceasing the burning of coal in the Foster-Wheeler Boiler by December 31, 2020), or 340-223-0060 and 340-223-0070, then the compliance date of July 1, 2014 in 340-223-0060(2)(b) and (c) (sulfur dioxide and particulate matter emissions limits) is delayed until three years from the date of EPA approval.

(4) Notwithstanding sections (1) and (3), if the EPA approves a revision to the State of Oregon Clean Air Act Implementation Plan that incorporates OAR 340-223-0030 (concerning BART requirements based upon permanently ceasing the burning of coal in the Foster-Wheeler Boiler by December 31, 2020), then OAR 340-223-0060 and 340-223-0070 are repealed, compliance with 340-223-0060 and 340-223-0070 in lieu of complying with 340-223-0030 is no longer an alternative, and compliance with 340-223-0030 or 340-223-0080 is required.

NOTE: This rule is included in the State of Oregon Clean Air Act Implementation Plan that EQC adopted under OAR 340-200-0040.

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

REPEAL: 340-223-0060

RULE TITLE: Alternative BART Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106) Based Upon Operation Until 2040 or Beyond

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Repealing rule because the Boardman Coal Fired Power Plant has been decommissioned.

RULE TEXT:

(1) Subject to OAR 340-223-0050, the owner or operator of the Foster-Wheeler boiler at the Boardman coal-fired power plant may elect to comply with this rule and 340-223-0070 in lieu of compliance with OAR 340-223-0030.

(2) Emissions limits:

(a) On and after July 1, 2011, nitrogen oxide emissions must not exceed 0.28 lb/mmBtu heat input as a 30-day rolling average and 0.23 lb/mmBtu heat input as a 12-month rolling average.

(A) If it is demonstrated by July 1, 2012 that the emissions limits in (a) cannot be achieved with combustion controls, the Department may grant an extension of compliance to July 1, 2014.

(B) If an extension is granted, on and after July 1, 2014 the nitrogen oxide emissions must not exceed 0.19 lb/mm Btu heat input as a 30-day rolling average, and the emissions limits of 0.28 lb/mmBtu heat input as a 30-day rolling average and 0.23 lb/mmBtu heat input as a 12-month rolling average no longer apply.

(b) On and after July 1, 2014, sulfur dioxide emissions must not exceed 0.12 lb/mmBtu heat input as a 30-day rolling average.

(c) On and after July 1, 2014, particulate matter emissions must not exceed 0.012 lb/mmBtu heat input as determined by compliance source testing.

(d) During periods of startup and shutdown, the following emissions limits apply instead of the limits in subsections (2)(a) through (c):

(A) Sulfur dioxide emissions must not exceed 1.20 lb/mmBtu, as a 3-hour rolling average;

(B) Nitrogen oxide emissions must not exceed 0.70 lb/mmBtu, as a 3-hour rolling average; and

(C) Particulate matter emissions must be minimized to extent practicable pursuant to approved startup and shutdown procedures in accordance with OAR 340-214-0310.

(3) Compliance demonstration. Using the procedures specified in section (4) of this rule:

(a) Compliance with a 30-day rolling average limit must be demonstrated within 180 days of the compliance date specified in section (2) of this rule.

(b) Compliance with a 12-month rolling average must be demonstrated within 12 months of the compliance date specified in section (2) of this rule.

(4) Compliance Monitoring and Testing.

(a) Compliance with the emissions limits in (2)(a), (b) and (d)(A)-(B) must be determined with a continuous emissions monitoring system (CEMS) installed, operated, calibrated, and maintained in accordance with the acid rain monitoring requirements in 40 CFR Part 75 as in effect on December 9, 2010.

(A) The hourly emissions rate in terms of lb/mmBtu heat input must be recorded each operating hour, including periods of startup and shutdown.

(B) The daily average emissions rate must be determined for each boiler operating day using the hourly emissions rates recorded in (A), excluding periods of startup and shutdown.

(C) 30-day rolling averages must be determined using all daily average emissions rates recorded in (B) whether or not the days are consecutive.

(D) 12-month rolling averages must be determined using calendar month averages based on all daily averages during the calendar month.

(b) Compliance with the particulate matter emissions limit in (2)(c) must be determined by EPA Methods 5 and 19 as in effect on December 9, 2010.

(A) An initial test must be conducted by January 1, 2015.

(B) Subsequent tests must be conducted in accordance with a schedule specified in the Oregon Title V Operating Permit, but not less than once every 5 years.
(C) All testing must be performed in accordance with the Department's Source Sampling Manual as in effect on December 9, 2010. [NOTE: DEQ manual is published with OAR 340-200-0035.]
(7) Notifications and Reports.
(a) The Department must be notified in writing within 7 days after any control equipment (including combustion controls) used to comply with emissions limits in section (2) begin operation.
(b) For nitrogen oxide and sulfur dioxide limits based on a 30-day rolling average, a compliance status report, including CEMS data, must be submitted within 180 days of the compliance dates specified in section (2).
(c) If applicable, a compliance status report for the 12-month rolling average nitrogen oxide limit in section (2)(a) must be submitted by August 1, 2012.
(d) For particulate matter, a compliance status report, including a source test report, must be submitted within 60 days of completing the initial compliance test specified in section (4)(b).
[NOTE: View a PDF of EPA Methods by clicking on "Tables" link below.]

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

REPEAL: 340-223-0070

RULE TITLE: Additional NOx Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106) Based Upon Operation Until 2040 or Beyond

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Repealing rule because the Boardman Coal Fired Power Plant has been decommissioned.

RULE TEXT:

(1) Subject to OAR 340-223-0050, the owner or operator of the Foster-Wheeler boiler at the Boardman coal-fired power plant may elect to comply with this rule and 340-223-0060 in lieu of compliance with OAR 340-223-0030.
(2) On and after July 1, 2017, nitrogen oxide emissions must not exceed 0.070 lb/mmBtu heat input as a 30-day rolling average, excluding periods of startup and shutdown.
(3) Compliance with the nitrogen oxide emissions limit in section (2) must be determined with a continuous emissions monitoring system in accordance with OAR 340-223-0060(3)-(4).
(4) The Department must be notified in writing within 7 days after any control equipment used to comply with the emissions limit in section (2) begins operation.
(5) A compliance status report, including CEMS data, must be submitted by January 1, 2018.

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

REPEAL: 340-223-0080

RULE TITLE: Alternative Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106) Based Upon Permanently Ceasing the Burning of Coal Within Five Years of EPA Approval of the Revision to the Oregon Clean Air Act State Implementation Plan Incorporating OAR Chapter 340, Division 223.

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: Repealing rule because the Boardman Coal Fired Power Plant has been decommissioned.

RULE TEXT:

(1) Subject to OAR 340-223-0050, the owner or operator of the Foster-Wheeler boiler at the Boardman coal-fired power plant may elect to comply with this rule in lieu of compliance with OAR 340-223-0030 if the boiler permanently ceases to burn coal within five years of the approval by the United States Environmental Protection Agency (EPA) of the revision to the State of Oregon Clean Air Act Implementation Plan that incorporates OAR chapter 340, division 223.

(2) Emissions limits:

(a) Beginning July 1, 2011, nitrogen oxide emissions must not exceed 0.23 lb/mmBtu heat input as a 30-day rolling average, provided that:

(A) If the source submitted a complete application for construction and/or operation of pollution control equipment to satisfy the emissions limit in subsection (2)(a) at least eight months prior to the compliance date of July 1, 2011, and the Department has not approved or denied the application by the compliance date, the compliance date is extended until the Department approves or disapproves the application, but may not be extended to a date more than five years from the date that the EPA approves a revision to the State of Oregon Clean Air Act Implementation Plan that incorporates OAR 340-223-0030; and

(B) If it is demonstrated by December 31, 2011 that the emissions limit in subsection (2)(a) cannot be achieved with combustion controls, the Department by order may grant an extension of compliance to July 1, 2013.

(b) During periods of startup and shutdown, the emissions limit in subsection (2)(a) does not apply, and nitrogen oxide emissions must not exceed 0.70 lb/mmBtu, as a 3-hour rolling average.

(c) The Foster-Wheeler boiler at the source must permanently cease burning coal by no later than five years after the approval by the EPA of the revision to the State of Oregon Clean Air Act Implementation Plan that incorporates OAR chapter 340, division 223. Notwithstanding the definition of netting basis in OAR 340-200-0020, and the process for reducing plant site emission limits in OAR 340-222-0043, the netting basis and PSELs for the boiler are reduced to zero upon the date on which the boiler permanently ceases burning coal, and prior to that date the netting basis and PSELs for the boiler apply only to physical changes or changes in the method of operation of the source for the purpose of complying with emission limits applicable to the boiler.

(3) Compliance demonstration. Using the procedures specified in section (4) of this rule, compliance with a 30-day rolling average limit must be demonstrated within 180 days of the compliance date specified in section (2) of this rule.

(4) Compliance Monitoring and Testing. Compliance with the emissions limit in subsection (2)(a) must be determined with a continuous emissions monitoring system (CEMS) installed, operated, calibrated, and maintained in accordance with the acid rain monitoring requirements in 40 CFR Part 75 as in effect on December 9, 2010.

(a) The hourly emission rate in terms of lb/mmBtu heat input must be recorded each operating hour, including periods of startup and shutdown.

(b) The daily average emission rate must be determined for each boiler operating day using the hourly emission rates recorded in (a), excluding periods of startup and shutdown.

(c) 30-day rolling averages must be determined using all daily average emissions rates recorded in (b) whether or not the days are consecutive.

(d) The daily average emission rate is calculated for any calendar day in which the boiler combusts any fuel. An operating hour means a clock hour during which the boiler combusts any fuel, either for part of the hour or for the entire hour.

(5) Notifications and Reports

(a) The Department must be notified in writing within 7 days after any control equipment (including combustion controls) used to comply with emissions limit in subsection (2)(a) begin operation.
(b) A compliance status report, including CEMS data, must be submitted within 180 days of the compliance date specified in section (2).

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

ADOPT: 340-223-0100

RULE TITLE: Screening Methodology for Sources for Round II of Regional Haze

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: New rule for Screening Methodology for Sources for Round II of Regional Haze

RULE TEXT:

(1) The following sources are subject to the requirements of round II of regional haze, contained in OAR 340-223-0110 to OAR 340-223-0130:

(a) Stationary sources with a Title V operating permit; and

(b) That have a Q/d, as determined as provided in subsection (2), of greater than or equal to 5.00.

(2) To determine Q/d, DEQ shall calculate:

(a) A "Q" factor by adding the plant site emission limits for round II regional haze pollutants as stated in the permit for that source as of December 31, 2017;

(b) A "d" factor by determining the source's physical distance to the closest Class 1 area in Oregon or an adjacent state in kilometers, measured in a straight line from the source to the nearest boundary of a Class I area; and

(c) The ratio of Q divided by d for that source.

[NOTE: This rule is included in the State of Oregon Clean Air Act Implementation Plan that EQC adopted under OAR 340-200-0040.]

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

ADOPT: 340-223-0110

RULE TITLE: Options for Compliance with Round II of Regional Haze

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: New rule for Options for Compliance with Round II of Regional Haze

RULE TEXT:

(1) All sources subject to the requirements of round II of regional haze, as determined in OAR 340-223-0100(1), must submit a four factor analysis as required under OAR 340-223-0120(1) and install all controls determined by DEQ to be cost effective for controlling round II regional haze pollutants on the fastest timeline determined by DEQ to be practicable and no later than July 31, 2026 based on the agency record at the time of its decision and in an order issued under OAR 340-223-0130(1) following DEQ's adjustment and review of the four factor analysis.

(2) DEQ may, but is not required to, offer alternative compliance with subsection (1) by entering into a stipulated agreement and final order under which a source agrees to take one of the actions identified in paragraphs (b)(A) through (E). A stipulated agreement and final order shall identify the action that shall be taken by the source and the timeline for the action, which shall be the fastest timeline determined by DEQ to be practicable as well any monitoring, recordkeeping, reporting, or other requirements that DEQ determines are necessary to ensure actions taken by the source are enforceable.

(a) If DEQ chooses not to enter into a stipulated agreement and final order under this subsection (2), a source shall comply with subsection (1).

(b) DEQ may enter into a stipulated agreement and final order in which a source agrees to:

(A) Accept federally enforceable reductions of combined plant site emission limits of round II regional haze pollutants to bring the source's Q/d below 5.00. Notwithstanding OAR 340-222-0040, a source may take a PSEL reduction below the generic PSEL to achieve an overall PSEL of round II regional haze pollutants below a Q/d of 5.00. A source's Q/d will be considered to be brought below 5.00 when Q/d is below 5.00 using the calculation in OAR 340-223-0100(2), except that the Q factor shall be calculated by adding the plant site emission limits for regional haze pollutants as stated in the stipulated agreement and final order;

(B) Install controls identified by the source in a four factor analysis as cost effective for that source for reducing round II regional haze pollutants. DEQ must agree that the controls identified will result in the greatest cost effective emissions reduction at the identified emissions unit and DEQ must establish a timeline for installation of those controls that is the fastest practicable timeline for installation of the identified controls and that is no later than July 31, 2026;

(C) Install controls or reduce emissions for round II regional haze pollutants that DEQ determines, in its sole discretion, provide equivalent emissions reductions to controls that would be identified as cost effective for that source following the adjustment and review of a four factor analysis. DEQ must establish a timeline for installation of those controls that is the fastest practicable timeline for installation of the identified controls and that is no later than July 31, 2026;

(D) Maintain controls that the source has already installed to control round II regional haze pollutants or maintain reduced emissions of regional haze pollutants that DEQ determines, in its sole discretion, have provided and will continue to provide equivalent emissions reductions to controls that would be identified as cost effective for that source following adjustment and review of a four factor analysis; or

(E) Replace an emissions unit with a new emissions unit that meets the emission limits and requirements of the most recent applicable standard in place at the time of the permitting of the new emissions unit. DEQ must establish a timeline for installation of the new emissions unit that is the fastest practicable timeline for installation of the new emissions unit and that is no later than July 31, 2031.

(c) The stipulated agreement and final order shall be incorporated into the source's Title V permit or upon permit renewal.

(3) If a source fails to take action as required under subsection (1) and DEQ has not entered into a stipulated agreement and final order with that source under subsection (2), DEQ shall complete a four factor analysis for that source, and the source shall install all controls to control round II regional haze pollutants determined by DEQ to be cost effective and

based on the fastest timeline determined by DEQ to be practicable and no later than July 31, 2026 in an order issued under OAR 340-223-0130 based on information compiled by DEQ in the agency record.
[NOTE: This rule is included in the State of Oregon Clean Air Act Implementation Plan that EQC adopted under OAR 340-200-0040.]

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

ADOPT: 340-223-0120

RULE TITLE: Four Factor Analysis

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: New rule for Four Factor Analysis for regional haze.

RULE TEXT:

(1) A four factor analysis is an emissions control analysis that shall include:

(a) All emissions units for the source; and

(b) Information sufficient to determine, at each emissions unit:

(A) The costs of any and all controls that could be used to reduce round II regional haze pollutants, including an estimate of the cost per ton of each round II regional haze pollutant reduced and all control technologies in use by similar emission units, either at that source or at other sources or locations;

(B) How soon the source believes it would be practicable to install to install controls identified under paragraph (A);

(C) The energy and non-air quality environmental impacts of installing controls identified under paragraph (A); and

(D) The remaining useful life of each emissions unit.

(2) If DEQ determines that the four factor analysis is inaccurate, inadequate, or insufficient, DEQ may request in writing additional information from the source and may adjust the four factor analysis based on any information submitted or may adjust the four factor analysis based on other information DEQ determines to be accurate, adequate, and sufficient. DEQ shall place any information submitted or relied on under this subsection into its record.

(3) DEQ may adjust information in the four factor analysis to assist DEQ in conducting a consistent review of submittals. DEQ shall place any information relied on under this subsection into its record.

(4) DEQ shall review the four factor analysis and any additional information that DEQ has placed in the agency record under subsections (2) and (3) to determine which controls, if any, would be cost effective to reduce round II regional haze pollutants for each emissions unit at a source and to determine what is the fastest practicable timeline for installation of the identified controls. In no event shall the timeline determined to be practicable be later than July 31, 2026.

(a) A control is cost effective if DEQ determines that the control will result in a cost of $10,000 or less per ton of reductions for any single or combination of round II regional haze pollutants.

(b) If multiple controls are cost effective at an emissions unit, DEQ shall identify as cost effective the control that will result in the greatest emissions reduction at the emissions unit.

[NOTE: This rule is included in the State of Oregon Clean Air Act Implementation Plan that EQC adopted under OAR 340-200-0040.]

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

ADOPT: 340-223-0130

RULE TITLE: Final Orders Ordering Compliance with Round II of Regional Haze

NOTICE FILED DATE: 05/28/2021

RULE SUMMARY: New rule for Final Orders Ordering Compliance with Round II of Regional Haze

RULE TEXT:

(1) For all sources identified in OAR 340-223-0100(1) that do not enter into a stipulated agreement and final order under OAR 340-223-0110(2), DEQ shall issue a final order no later than August 9, 2021, identifying:

(a) The action that shall be taken by the source pursuant to OAR 340-223-0110(1), as well any monitoring, recordkeeping, reporting, or other requirements that DEQ determines are necessary to ensure any controls or emission limits are actually implemented and are enforceable.

(b) The timeline under which the source shall complete the action in paragraph (a).

(2) The order issued under subsection (1) shall:

(a) Be a contested case order issued in compliance with ORS chapter 183;

(b) Be incorporated into the source's Title V permit in compliance with OAR 340-218-0200(1)(a)(A) or upon permit renewal.

(3) Notwithstanding OAR 340-011-0530(1), a party wishing to request a contested case hearing must do so in writing within ten days of the date of service of the order issued under subsection (1).

(4) In accordance with OAR 340-011-0530(2), due to the complexity of the regional haze program, the request for hearing based on an order issued under subsection (1) must include a written response that admits or denies all factual matters alleged in the notice, and alleges any and all affirmative defenses and the reasoning in support thereof. Due to the complexity, factual matters not denied will be considered admitted, and failure to raise a defense will be a waiver of the defense. New matters alleged in the request for hearing are denied by DEQ unless admitted in subsequent stipulation.

(5) DEQ shall refer all hearing requests received under subsection (3) to the Office of Administrative Hearings within five business days of receipt of the request. The cases shall be heard on an expedited timeline to the greatest extent practicable. All reasonable efforts shall be made for DEQ or the EQC to issue a final order within 90 days of receipt of the hearing request.

[NOTE: This rule is included in the State of Oregon Clean Air Act Implementation Plan that EQC adopted under OAR 340-200-0040.]

STATUTORY/OTHER AUTHORITY: ORS 468, 468A

STATUTES/OTHER IMPLEMENTED: ORS 468A.025

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF BIOMASS ONE, L.P. Permittee.	))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 15-0159

Permittee, Biomass One, L.P., and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a biomass power plant located at 2350 Ave G in White City, Oregon (the Facility).

2. On February 28, 1996, DEQ issued Title V Operating Permit No. 15-0159-TV-01 (the Permit) to Permittee.

3. On May 12, 2020, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2), at the Facility: 469 tons per year for NOx, 31 tons per year for PM10 and 39 tons per year for SO2.

6. The Facility is located 56.4 kilometers from Mountain Lakes Wilderness, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 539; d value is 56.4, and ratio of Q divided by d is 9.6.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable reductions of combined plant site emission limits of round II regional haze pollutants and performance limits which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(b)(A).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(A), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the emission reductions schedule in Section II of this SAFO.

4. The PSEL reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-200(1)(a)(A), as applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial

review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. By July 31, 2022, Permittee shall install CEMS to measure the emissions of NOx from North Boiler and South Boiler. Permittee shall install the CEMS according to the following installation, quality control, and quality assurance requirements:
   a. By September 31, 2022, Permittee shall demonstrate proper installation of the CEMS following EPA Procedure 1 (see 40 CFR 60, Appendix F, Procedure 1), Performance Specification 2 (see 40 CFR 60, Appendix F, Performance Specification 2), and DEQ Continuous Monitoring Manual, Rev. 2015.
   b. By December 31, 2022, Permittee shall submit data collected during demonstrations required under Section II.1.a to DEQ for review and certification of the CEMS.
   c. Upon DEQ's approval of the CEMS certification, Permittee shall use data collected from the CEMS to minimize NOx operations to the extent practicable.
   d. Permittee shall collect and record all data from the NOx CEMS and make that data available to DEQ upon request.
2. Within 180 days after installation of the NOx CEMS in Section II.1, Permittee shall submit to DEQ a NOx optimization plan that describes Permittee's plan to use the CEMS data to operate in a way that minimizes NOx emissions. Permittee will implement the NOx optimization plan at all times after submitting it to DEQ.
3. If Permittee is able to finalize a new power purchase agreement (PPA), Permittee shall notify DEQ in writing within 14 calendar days. Or, if no new PPA is signed, Permittee shall cease operation by January 1, 2027 and request cancellation of their Title V operating permit.
4. If a new PPA is signed, then no later than 180 days after notifying DEQ of the new PPA, the Permittee shall submit a complete application for installation of NOx reduction technology that includes selective catalytic reduction (SCR) on the North

Boiler and South Boiler or demonstrates SCR is technically infeasible or presents other unacceptable energy or non-air quality impacts. If SCR is technically infeasible or presents such other unacceptable impacts, the Permittee will propose the best available, technically feasible, and achievable NOx reduction option for DEQ's review and approval. DEQ will notify Permittee and provide Permittee with a reasonable opportunity to comment before approving a NOx reduction option in response to Permittee's application under this Section II.4.

5. Permittee shall complete installation of the controls approved by DEQ in Section II.4 within 18 months after receiving the necessary approvals from DEQ. After installation of the identified controls, Permittee will operate using those controls at all times.

BIOMASS ONE, L.P. (PERMITTEE)

8/9/2021
Date

Gregory R Bla.
Signature

Gregory R Blair
Name (print)

President, National Public Energy, Inc., its Managing General Partner
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/9/2021
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Boise Cascade Wood Products, L.L.C. Medford Permittee.	)))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 15-0004

Permittee and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a wood products facility located at 3285 N Pacific Highway in Medford, Oregon (the Facility).

2. On July 1, 1997, DEQ issued Title V Operating Permit No. 15-0004-TV-01 (the Permit) to Permittee.

3. On February 20, 2020, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2) at the Facility: 31 tons per year for SO2, 167 tons per year for PM10 and 227 tons per year for NOx.

6. The Facility is located 60.6 kilometers from Mountain Lakes Wilderness, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 425; d value is 60.6, and ratio of Q divided by d is 7.02.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable reductions of combined plant site emission limits of round II regional haze pollutants to bring the Facility's Q/d below 5.00 which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(b)(A).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(A), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL (PM10 + NOx + SO2) reductions schedule in Section II of this SAFO.

4. The PSEL reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions except Permittee may retain unassigned emissions not subject to reduction pursuant to OAR 340-222-0055(3)(c).

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-0200(1)(a)(A), as applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

9. Permittee waives any and all rights and objections Permittee may have to the form,

content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, work interference caused by pandemic, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original

signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. The Permittee shall comply with the PSELs according to the following schedule:

   a. From August 1, 2021, to July 31, 2023, the Permittee's PSELs for the following pollutants are:

      i. 396 tons for PM10 + NOx + SO2.(Q/d = 6.53).

   b. From August 1, 2023, to July 31, 2024, the Permittee's PSELs for the following pollutants are:

      i. 381 tons for PM10 + NOx + SO2 (Q/d = 6.29).

   c. From On August 1, 2024, to July 31, 2025 the Permittee's PSELs for the following pollutants are:

      i. 365 tons for PM10 + NOx + SO2 (Q/d = 6.03) .

   d. From August 1, 2025, to July 31, 2026 the Permittee's PSELs for the following pollutants are:

      i. 347 tons for PM10 + NOx + SO2 (Q/d = 5.73).

   e. On August 1, 2026, the Permittee's PSELs for the following pollutants are:

      i. 302 tons for PM10 + NOx + SO2 (Q/d = 4.99).

BOISE CASCADE WOOD PRODUCTS, LLC.
(PERMITTEE)

August 9, 2021
Date

[signature]
Signature

Robert Glover
Name (print)

Region Manager - Boise Cascade
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/9/2021

Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Cascade Tissue Group – Oregon, a division of Cascades Holding US Inc. Permittee.	))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 05-1849

Permittee, Cascade Tissue Group – Oregon, a division of Cascades Holding US Inc., and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a paper mill located at 1300 Kaster Road, Saint Helens, Oregon (the Facility).

2. On July 1, 1996, DEQ issued Title V Operating Permit No. 05-1849-TV-02 (the Permit) to Permittee.

3. On April 6, 2018, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2) at the Facility: 3400 tons per year for SO2, 738 tons per year for PM10 and 1449 tons per year for NOx.

6. Upon renewal, issued April 6, 2018, the Permit was modified to reduce the PSELs to 39 tons per year for SO2, 14 tons per year for PM10 and 103 tons per year for NOx, and the Permit included condition 23, which documented the following unassigned emissions: 3322 tons for SO2, 739 tons for PM 10, and 1386 tons for NOx.

7. The Facility is located 87.7 kilometers from Mount Hood Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

8. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 5587; d value is 87.7, and ratio of Q divided by d is 63.71.

9. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

10. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to remove and forfeit banked unassigned emissions, and accept the PSELs in effect on April 6, 2018 in their Title V operating permit as compliance with round II of regional haze, which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(b)(A).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(A), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions schedule in Section II of this SAFO.

4. The PSEL and unassigned emissions reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-0200(1)(a)(A), if applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any unforeseen event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's

control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. The Permittee shall comply with the PSELs according to the following schedule:
   a. On August 1, 2022, the Permittee's PSELs for the following pollutants are:
      i. 39 tons per year for SO2, 14 tons per year for PM10 and 103 tons per year for NOx.

2. Unassigned emissions for SO2, PM10, and NOx will be set to 0.

Cascade Tissue Group - Oregon (PERMITTEE)

8/18/2021
Date

Signature

Jonathan Bouchard
Name (print)

Plant Manager
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/18/2021
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF EVRAZ Inc. NA Permittee.	)))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 26-1865

Permittee, EVRAZ Inc. NA, and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a steel mill located at 14400 N Rivergate Boulevard in Portland, Oregon (the Facility).

2. On December 15, 2000, DEQ issued Title V Operating Permit No. 26-1865-TV-01 (the Permit) to Permittee.

3. On March 27, 2018, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2): 39 tons per year for SO2, 340 tons per year for PM10, and 493 tons per year for NOx. Specifically, the Permit authorized these discharges from the following emissions units, as defined in OAR 340-223-0020(1): from EU-10 Reheat Furnace at the Facility.

6. The Facility is located 73.1 kilometers from Mount Hood Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020 (25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2), the Facility's Q value is 872; d value is 73.1, and ratio of Q divided by d is 11.9.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept a federally enforceable requirement to conduct source testing and accept emission limitations to reduce round II regional haze pollutants from the Facility which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions, emission limit, controls, and conditions in Section II of this SAFO.

4. The reductions to PSELs required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-0200(1)(a)(A), as applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any unforeseen event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control, unforeseen, and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. By December 31, 2024, Permittee shall, at a minimum, install low NOx burners on the pre-heat portions of EU-10 Reheat Furnace with a designed NOx emission factor of 170 pounds per million cubic feet of natural gas.
2. During 2025, the Permittee shall conduct an initial NOx source testing campaign on EU-10 Reheat Furnace to verify the designed NOx emission factor.
   a. The initial NOx source testing campaign shall consist of quarterly source testing on EU-10 Reheat Furnace to verify the designed NOx emission factor. Each quarterly source test shall consist of a minimum of three (3) test runs, using EPA Reference Method 7E.
3. Within 90 days of completing the initial NOx source testing campaign, the Permittee shall submit a report to DEQ that includes the source testing results, and proposes a new NOx emission factor for EU-10 Reheat Furnace.
   a. DEQ will review Permittee's report provided under this section and determine the appropriate NOx emissions factor for the EU-10 Reheat Furnace. DEQ will notify the Permittee and provide opportunity to discuss the emissions factor.
   b. After consultation with the Permittee, DEQ will calculate the new potential to emit (PTE) from EU-10 Reheat Furnace using the new NOx emission factor determined under this section. DEQ will adjust Permittee's NOx PSEL in its permit to account for the revised PTE, either pursuant to OAR 340-218-0200(1)(a)(A), as applicable, or upon permit renewal.

EVRAZ Inc. NA (PERMITTEE)

8-9-2021
Date

Signature

DON HUNTER
Name (print)

SR. VICE PRESIDENT - PORTLAND B.U.
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/9/2021
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Gas Transmission Northwest LLC Compressor Station #12 Permittee.	)))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 09-0084

Permittee, Gas Transmission Northwest LLC, and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a natural gas compressor station located at US Highway 97, 19 miles south of Bend in Bend, Oregon (the Facility).

2. On July 9, 1996, DEQ issued Title V Operating Permit No. 09-0084-TV-01 (the Permit) to Permittee.

3. On August 10, 2017, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2) at the Facility: 39 tons per year for SO2, 14 tons per year for PM 10, and 377 tons per year for NOx.

6. The Facility is located 30.4 kilometers from the Three Sisters Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 430; d value is 30.4, and ratio of Q divided by d is 14.1.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable reductions of combined plant site emission limits of round II regional haze pollutants to bring the Facility's Q/d below 5.00 which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(b)(A).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(A), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions schedule in Section II of this SAFO.

4. The PSEL reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not exceed the limits established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to 340-218-0200(1)(a)(A), if applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial

review of the SAFO.

10. In the event EPA does not accept DEQ’s Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee shall negotiate modifications to the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee’s obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any event occurs that is beyond Permittee's reasonable control and that causes a deviation in performance of the requirements of this SAFO, Permittee must notify DEQ as soon as possible via email and follow up with a phone call providing verbally the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate that the delay or deviation has been caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. The Permittee shall comply with the PSELs according to the following schedule:
   a. On August 1, 2022, the Permittee's PSELs for the following pollutants are:
      i. 12.7 tons per year for PM10; 317.1 tons per year for NOx; and 30.4 tons per year for SO2.
   b. On August 1, 2023, the Permittee's PSELs for the following pollutants are:
      i. 11.4 tons per year for PM10; 257.2 tons per year for NOx; and 21.7 tons per year for SO2.
   c. On August 1, 2024, the Permittee's PSELs for the following pollutants are:
      i. 10.2 tons per year for PM10; 197.3 tons per year for NOx; and 13.1 tons per year for SO2.
   d. On August 1, 2025, the Permittee's PSELs for the following pollutants are:
      i. 8.9 tons per year for PM10; 137.4 tons per year for NOx; and 4.4 tons per year for SO2.

GAS TRANSMISSION NORTHWEST LLC
(PERMITTEE)

August 9, 2021
Date

By: DocuSigned by: John McWilliams 05C8C56BD85546D...
John J. McWilliams, Vice-President

DS JH

By: DocuSigned by: Emily Strait 7BE179CD86EB4C0...
Emily L. Strait, Assistant Secretary

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

August 9, 2021
Date

DocuSigned by: Y. Ali Mirzakhalili 7895034861B1468...
Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Georgia-Pacific Toledo LLC Toledo Permittee.	)))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 21-0005

Permittee, Georgia-Pacific Toledo LLC, and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a pulp and paper mill located at 1400 SE Butler Bridge Road in Toledo, Oregon (the Facility).

2. On July 1, 1997, DEQ issued Title V Operating Permit No. 21-0005-TV-01 (the Permit) to Permittee.

3. On September 9, 2016, DEQ issued the most recent renewal Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, see OAR 340-223-0020(2): 437 tons per year for SO2, 311 tons per year for PM10, and 1343 tons per year for NOx.

6. The Facility is located 147.0 kilometers from Three Sisters Wilderness, which is the nearest Class I Area, *see* OAR 340-200-0020 (25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2), the Facility's Q value is 2091; d value is 147.0, and ratio of Q divided by d is 14.2.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. See OAR 340-223-0100(1).

9. In accordance with OAR 340-223-0110(1), the Facility submitted a four factor analysis demonstrating that many identified emission unit/control combinations are not cost effective. Rather than agreeing to install all emission unit/control combinations determined to be cost effective by DEQ, the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept a federally enforceable requirement to install controls and associated monitoring equipment, and to accept emission limitations to reduce round II regional haze pollutants from the Facility which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions, emission limits, controls, monitoring requirements, schedules, and conditions in Section II of this SAFO.

4. The reductions in PSELs required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-0200(1)(a)(A) or upon permit renewal, whichever is sooner.

8. DEQ may submit this SAFO to the Environmental Protection Agency (EPA) as part of the State Implementation Plan.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP. In the event that EPA has disapproved DEQ's Round II Regional Haze SIP and promulgates a Round II Regional Haze federal implementation plan, this agreement will be void.

11. Permittee releases and waives any and all claims of any kind, known or unknown, past or future, against the State of Oregon or its agencies, instrumentalities, employees, officers, or agents, arising out of the matters and events relating to the matter set out in this SAFO. Any and all claims includes but is not limited to any claim under 42 USC § 1983 et seq., any claim under federal or state law for damages, declaratory, or equitable relief, and any claim for attorneys fees or costs.

12. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

13. If any unforeseeable event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee

shall confirm in writing this information within five working days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control, unforeseen, and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, unforeseen delays in issuance of any required permits by DEQ that are beyond the Permittee's control, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

14. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

15. The obligations and requirements in this SAFO may be revised at Permittee's request, e.g., to authorize different but equivalent emission reductions or controls, if DEQ approves such proposed revisions in writing through an amendment to this SAFO.

II. FINAL ORDER

DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. For the EU-11 No. 4 Boiler, EU-13 No. 1 Boiler, and EU-18 No. 3 Boiler:
   a. Permittee shall either complete a NOx reduction project that includes the installation of low NOx burners, flue gas recirculation and continuous emissions monitoring system (CEMS) on the three Boilers, EU-11, EU-13, and EU-18, or replace the boilers with one or more new boilers.
      i. Permittee shall determine whether to complete the NOx reduction project or replace the boilers by July 31, 2022 and shall meet with DEQ by December 31, 2022 to discuss the technical details of the selected project to determine what permitting Permittee shall need prior to construction.

Permittee and DEQ shall agree to a timeline for permitting of construction project in the meeting, including required deadlines for submittal of a complete approvable permit application.

ii. If Permittee chooses to complete a NOx reduction project:

1. By July 31, 2026, Permittee shall install low NOx burners and flue gas recirculation on EU-11, EU-13, and EU-18 in order to achieve an emissions rate no greater than 0.09 lb/MMBtu on a seven day rolling basis. This deadline shall be extended if, in response to a complete application submitted by Permittee in accordance with the timeline established under Section II.2.a.i, DEQ does not provide construction approval on a timely basis.
2. As expeditiously as practicable, but not later than July 31, 2026, Permittee shall install a CEMS to measure the emissions of NOx from EU-11, EU-13, and EU-18. Permittee shall install the CEMS according to the installation, quality control, and quality assurance requirements detailed in the following:
3. Permittee shall demonstrate proper installation of the CEMS following EPA Procedure 1 (see 40 CFR 60, Appendix F, Procedure 1), Performance Specification 2 (see 40 CFR 60, Appendix B, Performance Specification 2), and DEQ Source Sampling Manual, Rev. 2018.
4. Permittee shall submit data collected during demonstrations to DEQ for review and to determine if the CEMS was installed correctly and meets the identified quality assurance criteria.
5. Upon DEQ's approval of the CEMS certification, Permittee shall use data collected from the CEMS to demonstrate compliance

with the applicable NOx PSEL listed in Section II, paragraph 1 above.

6. Permittee shall collect and record all data from the NOx CEMS and make that data available to DEQ upon request.

iii. If Permittee chooses to replace EU-11, EU-13, and EU-18:

1. PSELs for round II regional haze pollutants incorporated in the Permit for the replacement shall be no more than the potential to emit of the replacement, or a Q of 889 tons per year of NOX, 437 tons per year of SO2, and 311 tons per year of PM10 , whichever is lower.

2. Permittee shall complete the replacement of the EU-11, EU-13, and EU-18 with new technology no later than July 31, 2031. This deadline shall be extended if, in response to a complete approvable application submitted by Permittee in accordance with the timeline established under Section II.1.a.i, DEQ does not provide construction approval on a timely basis.

3. The Permittee shall not operate EU-11, EU-13, and EU-18 after July 31, 2031.

Georgia-Pacific Toledo LLC (PERMITTEE)

8/9/21
Date

Jeremy Ness
Signature

Jeremy Ness
Name (print)

VP Mill Manager
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/9/2021
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Georgia-Pacific Consumer Operations LLC Wauna Mill, Permittee.	)))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 04-0004

Permittee, Georgia-Pacific Consumer Operations LLC, and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a pulp and paper mill located at 92326 Taylorville Road in Clatskanie, Oregon (the Facility).

2. On January 2, 1996, DEQ issued Title V Operating Permit No. 04-0004-TV-01 (the Permit) to Permittee.

3. On June 18, 2009, DEQ renewed the Permit, and on December 2, 2010, DEQ issued the current permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2): 913 tons per year for SO2, 1,077 tons per year for PM10, and 2,139 tons per year for NOx.

6. The Facility is located 131.17 kilometers from Mount Rainer National Park, which is the nearest Class I Area, *see* OAR 340-200-0020 (25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2), the Facility's Q value is 4129; d value is 131.17, and ratio of Q divided by d is 31.48.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. In accordance with OAR 340-223-0110(1), the Facility submitted a four factor analysis demonstrating that many identified emission unit/control combinations are not cost effective. Rather than agreeing to install all emission unit/control combinations determined to be cost effective by DEQ, the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept a federally enforceable requirement to install controls and associated monitoring equipment, and to accept emission limitations to reduce round II regional haze pollutants from the Facility which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions, emission limits, controls, monitoring requirements, schedules, and conditions in Section II of this SAFO.

4. The reductions in PSELs required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-0200(1)(a)(A) or upon permit renewal, whichever is sooner.

8. DEQ may submit this SAFO to the Environmental Protection Agency (EPA) as part of the State Implementation Plan.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP. In the event that EPA has disapproved DEQ's Round II Regional Haze SIP and promulgates a Round II Regional Haze federal implementation plan, this agreement will be void.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any unforeseeable event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five working days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control, unforeseen, and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond

Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, unforeseen delays in issuance of any required permits by DEQ that are beyond the Permittee's control, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

14. The obligations and requirements in this SAFO may be revised at Permittee's request, e.g., to authorize different but equivalent emission reductions or controls, if DEQ approves such proposed revisions in writing through an amendment to this SAFO.

II. FINAL ORDER

DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. Permittee shall comply with the PSELs according to the following schedule :
   a. On August 1, 2022, Permittee's PSELs shall incorporate the changes listed in II.3. and, for the following pollutants, are:
      i. For PM10, the PSEL shall be 1,077 tons;
      ii. For NOx, the PSEL shall be 2,019 tons; and
      iii. For SO2, the PSEL shall be 913 tons.
   b. On December 31, 2024, the Permittee's PSELs shall incorporate the changes listed in II.2 and II.3. and, for the following pollutants, are:
      i. For PM10, the PSEL shall be 1,077 tons;
      ii. For NOx, the PSEL shall be 1,999 tons; and
      iii. For SO2, the PSEL shall be 913 tons.
   c. On July 31, 2026, the Permittee's PSELs shall incorporate the changes listed in II.2., II.3., and II.4. and, for the following pollutants, are:
      i. For PM10, the PSEL shall be 1,077 tons;

ii. For NOx, the PSEL shall be 1,413 tons; and

iii. For SO2, the PSEL shall be 913 tons.

2. For Paper Machine 5: Yankee Burner:

a. By December 31, 2024, Permittee shall replace the existing Yankee burner with a low NOx burner to achieve an emissions rate no greater than 0.03 lb/MMBtu and shall use this emission rate for calculating compliance with PSELs.

b. Permittee shall demonstrate compliance with the PSEL through performance testing following EPA Test Method 7E (see 40 CFR Part 60, Appendix A-4), or an alternate test method approved by DEQ, and shall comply with DEQ Source Sampling Manual, Rev. 2018.

c. Permittee shall demonstrate compliance through performance testing within one calendar year after the project is fully executed.

3. For Paper Machine 6: TAD1 Burner and TAD2 Burner, Paper Machine 7: TAD1 Burner and TAD 2 Burner:

a. Permittee shall have a NOx emissions rate no greater than 0.06 lb/MMBtu for each emissions point and shall use this emission rate for calculating compliance with PSELs.

b. Permittee shall demonstrate compliance with PSEL through performance testing following EPA Test Method 7E (see 40 CFR Part 60, Appendix A-4), or an alternate test method approved by DEQ, and shall comply with DEQ Source Sampling Manual, Rev. 2018.

c. Permittee shall demonstrate compliance through performance testing within one calendar year after this agreement is fully executed.

4. For the Power Boiler – 33:

a. By December 31, 2022, Permittee shall meet with DEQ to discuss the technical details of the low NOx burner, flue gas recirculation, and continuous emissions monitoring system (CEMS) installation project to determine what permitting

Permittee shall need prior to construction. Permittee and DEQ shall agree to a timeline for permitting of construction project in the meeting, including required deadlines for submittal of a complete approvable permit application.

b. As expeditiously as practicable, but not later than July 31, 2026, Permittee shall install low NOx burners and flue gas recirculation in order to achieve an emissions rate no greater than 0.09 lb/MMBtu on a seven day rolling basis. If the project results in the Power Boiler - 33 becoming an affected facility under 40 CFR 60.40b, demonstration of compliance shall be on a 30-day rolling basis rather than a seven-day rolling basis in accordance with 40 CFR 60.44b(i).

c. Within one year of completing the Power Boiler project in Section II.4.b, but no later than July 31, 2026, Permittee shall install a CEMS to measure the emissions of NOx from Power Boiler - 33. Permittee shall install the CEMS according to the installation, quality control, and quality assurance requirements detailed in the following:

    i. Permittee shall demonstrate proper installation of the CEMS following EPA Procedure 1 (see 40 CFR 60, Appendix F, Procedure 1),), Performance Specification 2 (see 40 CFR 60, Appendix B, Performance Specification 2), and DEQ Source Sampling Manual, Rev. 2018.

    ii. Permittee shall submit data collected during testing identified in Section II.4.c.i of this Final Order to DEQ for review and to determine if the CEMS was installed correctly and meets the identified quality assurance criteria.

d. Upon DEQ's approval of the CEMS certification, Permittee shall use data collected from the CEMS to demonstrate compliance with the applicable NOx PSEL listed in Section II, paragraph 1 above.

e. Permittee shall collect and record all data from the NOx CEMS and make that data available to DEQ upon request.

Georgia-Pacific Consumer Operations LLC (PERMITTEE)

8/9/21
Date

Signature
Jeremy Ness
Name (print)
VP Mill Manager
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/9/2021
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF International Paper Company Springfield Mill Permittee.	)))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 208850

Permittee (International Paper Company - Springfield Mill), Lane Regional Air Protection Agency (LRAPA), and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a pulp and paper mill located at 801 42nd Street in Springfield, Oregon (the Facility).

2. On June 30, 2005, LRAPA issued Title V Operating Permit No. 208850 (the Permit) to Permittee.

3. On December 14, 2012, LRAPA renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following Plant Site Emission Limits (PSELs) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2) at the Facility: 1,521 tons per year for SO2, 750 tons per year for PM10 and 1,692 tons per year for NOx (as 12-month rolling averages).

6. The Facility is located 58.9 kilometers from Three Sisters Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 3963; d value is 58.9, and ratio of Q divided by d is 67.3.

8. Because the Facility has a Title V Operating Permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable requirements to install and continually operate control devices, monitoring equipment and accept emission limitations to reduce round II regional haze pollutants from the Facility which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(b)(A).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(A), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and must ensure compliance with the PSEL reductions, emission limits, and Continuous Emission Monitoring System (CEMS) installation schedules and conditions in Section II of this SAFO.

4. The PSEL reductions required by this SAFO may not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee must calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. LRAPA shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-200(1)(a)(A), if applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's

failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. On and after July 31, 2022, the Permittee's combined assigned PSELs for the Power Boiler, Package Boiler, Lime Kilns and Recovery Furnace for the following pollutants are:
   a. 237 tons per year for SO2, as a 12-month rolling average.
   b. 962 tons per year for NOx, as a 12-month rolling average.
   c. 177 tons per year for PM10, as a 12-month rolling average.
2. Permittee agrees that the only fuel that it may combust in the Power Boiler and Package Boiler at the facility is natural gas, except that it may operate the Power Boiler and Package Boiler on ultra-low sulfur diesel for no more than 48 hours per year and when needed for natural gas curtailments.
3. Permittee agrees that the only fuels that it may combust in the Recovery Furnace are Black Liquor Solids (BLS) and natural gas, except that it may operate the Recovery Furnace on ultra-low sulfur diesel no more than 48 hours per year and when needed for natural gas curtailment.
4. Permittee agrees that the only fuels that it may combust in the Lime Kilns are natural gas, product turpentine and product methanol, except that it may operate the Lime Kilns on ultra-low sulfur diesel no more than 48 hours per year and when needed for natural gas curtailment.
5. By December 31, 2022, Permittee shall install CEMS and measure the emissions of NOx from the Power Boiler. Permittee shall install the CEMS according to the

installation, quality control, and quality assurance requirements detailed in the following:

a. Permittee shall demonstrate proper installation of the CEMS following EPA Procedure 1 (see 40 CFR 60, Appendix F, Procedure 1), Performance Specification 2 (see 40 CFR 60, Appendix B, Performance Specification 2), and DEQ Source Sampling Manual, Rev. 2018, no later than March 31, 2023.

b. Permittee shall submit data collected during testing identified in Section II.5 to DEQ and LRAPA for review.

c. Upon DEQ's and LRAPA's approval of the CEMS certification, Permittee shall use data collected from the CEMS to demonstrate compliance with the NOx emissions rates in Section II.6 & 7.

d. Permittee shall ensure that the CEMS are certified by DEQ and LRAPA no later than May 31, 2023.

e. Permittee shall use the CEMS to document Power Boiler emissions, replacing the equation in Condition 186.g in the LRAPA permit that requires monitoring of the Power Boiler NOx, no later than May 31, 2023.

f. Permittee shall collect and record all data from the NOx CEMS and make that data available to DEQ and/or LRAPA upon request.

6. On and after January 31, 2025, Permittee shall meet the following emission limit:

a. 0.25 lb NOx/MMBtu on a 7-day rolling average from the Power Boiler

7. On and after December 31, 2025, the Permittee's assigned PSEL for the following pollutants and Emission Unit is:

a. 179 tons per year for NOx, as a 12-month rolling average for the Power Boiler.

International Paper (PERMITTEE)

8/9/2021
Date

Signature

Douglas Black
Name (print)

Mill Manager - Springfield Mill
Title (print)

8-9-21	LANE REGIONAL AIR PROTECTION AGENCY
Date	Steven A. Dietrich
	Steven A. Dietrich, Director

8/9/2021	DEPARTMENT OF ENVIRONMENTAL QUALITY and ENVIRONMENTAL QUALITY COMMISSION
Date	Ali Mirzakhalili, Administrator Air Quality Division on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Owens-Brockway Glass Container Inc. Permittee.	))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 26-1876

Permittee, Owens-Brockway Glass Container Inc., and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a glass manufacturing facility located at 9710 NE Glass Plant Road in Portland, Oregon (the Facility).

2. On November 1, 1997, DEQ issued Title V Operating Permit No. 26-1876-TV-01 (the Permit) to Permittee.

3. On December 10, 2019, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2) at the Facility: 313 tons per year SO2, 132 tons per year PM10 and 711 tons per year NOx.

6. The Facility is located 55.1 kilometers from Mount Hood Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 1156; d value is 55.1, and ratio of Q divided by d is 21.0.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable reductions of combined plant site emission limits of round II regional haze pollutants to bring the Facility's Q/d below 5.00 which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(b)(A).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(A), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions schedule in Section II of this SAFO.

4. The Permittee has previously ceased operations of Furnace B and Furnace C and agrees that it will not operate Furnace B or Furnace C in the future.

5. The PSEL reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

6. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

7. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

8. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-200(1)(a)(A), or upon permit renewal.

9. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

10. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

11. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

12. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

13. If any unforeseen event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

14. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. On and after the execution of this Final Order:

    a. Permittee shall not operate Furnace A.

2. On and after January 1, 2022, the Permittee shall comply with the following PSELs, which apply to each 12 consecutive calendar month period after that date:

    i. 55 tons per year for PM10; 137 tons per year for NOx; and 108 tons per year for SO2.

    b. Unassigned emissions shall be set to 0.

    c. The netting basis for Furnace A, Furnace B, and Furnace C shall be removed from the total netting basis of the Facility.

3. On July 31, 2025, the Permittee's PSELs for the following pollutants are:

    i. 274.95 tons per year for PM10 + NOx + SO2 (Q/d = 4.99).

Owens Brockway Glass Container (PERMITTEE)

8-8-21
Date

Signature

William D Mann
Name (print)

VP Operations, N.A.
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/9/2021
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Roseburg Forest Products Co. Permittee.	))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 10-0025

Permittee, Roseburg Forest Products Co., and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a wood products facility located at Old Highway 99S in Dillard, Oregon (the Facility).

2. On October 20, 1997, DEQ issued Title V Operating Permit No. 10-0025-TV-01 (the Permit) to Permittee.

3. On April 13, 2021, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2): 113 tons per year for SO2, 683 tons per year for PM10, and 1655 tons per year for NOx.

6. The Facility is located 81.8 kilometers from Kalmiopsis Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020 (25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2), the Facility's Q value is 2451; d value is 81.8, and ratio of Q divided by d is 29.97.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept a federally enforceable requirement to install and continually operate control devices, pollution prevention equipment, monitoring equipment and accept emission limitations to reduce round II regional haze pollutants from the Facility which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions, emission limits, and controls and CEMS installation schedules and conditions in Section II of this SAFO.

4. The reductions to PSELs required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-0200(1)(a)(A), if applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the Clean Air Act State Implementation Plan.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any unforeseen event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) working days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control, unforeseen, and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. By July 31, 2022, Permittee shall install CEMS to measure the emissions of NOx from Boiler 1, Boiler 2 and Boiler 6. Permittee shall install the CEMS according to the following installation, quality control, and quality assurance requirements:
   a. By September 31, 2022, Permittee shall demonstrate proper installation of the CEMS following EPA Procedure 1 (see 40 CFR 60, Appendix F, Procedure 1), Performance Specification 2 (see 40 CFR 60, Appendix B, Performance Specification 2), and DEQ Source Continuous Monitoring Manual, Rev. 2015.
   b. By December 31, 2022, Permittee shall submit data collected during demonstrations required under Section II.1.a to DEQ for review and approval of the CEMS.
   c. Upon DEQ's approval of the CEMS certification, Permittee shall use data collected from the CEMS to demonstrate compliance with the applicable NOx emission limits listed in Section II.2 and II.4.
   d. Permittee shall collect and record all data from the NOx CEMS and make those data available to DEQ upon request.
2. From January 31, 2023 until June 30, 2025, Permittee shall meet the following emission limits:
   a. 0.30 lb NOx/MMBtu on a 7-day rolling average at Boiler 1;
   b. 0.30 lb NOx/MMBtu on a 7-day rolling average at Boiler 2;
   c. 0.28 lb NOx/MMBtu on a 7-day rolling average at Boiler 6; Or

d. Average of emissions from Boiler 1, Boiler 2, and Boiler 6 of 0.28 lb NOx/MMBtu (7-day rolling average).

3. By January 31, 2024, the Permittee shall notify DEQ in writing whether the Permittee will comply with the emission limits in Section II.4 using boiler optimization or through the installation of Selective Non-Catalytic Reduction controls (SNCR).

a. If the Permittee determines that the installation of SNCR controls are required to meet the emission limits in Section II.4, SNCR shall be installed, permitted, and operational by June 30, 2025.

b. Permittee shall submit a complete permit application for construction and operation of the SNCR by June 30, 2024.

4. On and after June 30, 2025, Permittee shall meet the following emission limits:

a. 0.27 lb NOx/MMBtu on a 7-day rolling average at Boiler 1;

b. 0.26 lb NOx/MMBtu on a 7-day rolling average at Boiler 2;

c. 0.26 lb NOx/MMBtu on a 7-day rolling average at Boiler 6; Or

d. Average of emissions from Boiler 1, Boiler 2, and Boiler 6 of 0.25 lb NOx/MMBtu (7-day rolling average).

Roseburg Forest Products Co. (PERMITTEE)

8/9/2021
Date

Stuart W. Gray
Signature

Stuart W. Gray
Name (print)

SVP General Counsel & Secretary
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/9/2021
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Willamette Falls Paper Company, Inc. Permittee.	))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 03-2145

Permittee, Willamette Falls Paper Company, Inc., and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a paper mill located at 4800 Mill Street in West Linn, Oregon (the Facility).

2. On October 31, 1995, DEQ issued Title V Operating Permit No. 03-2145-TV-01 (the Permit) to Permittee.

3. On February 24, 2016, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2), at the Facility: 743 tons per year for SO2, 84 tons per year for PM10, and 396 tons per year for NOx.

6. The Facility is located 53.7 kilometers from Mount Hood Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2), the Facility's Q value is 1,422; d value is 53.7, and ratio of Q divided by d is 26.5.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable reductions of combined PSEL of round II regional haze pollutants to bring the Facility's Q/d below 5.00 and remove #6 fuel oil as a permitted fuel source from their Title V operating permit, which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(b).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(A), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions schedule in Section II of this SAFO.

4. The PSEL reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-200(1)(a)(A), as applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

9. Permittee waives any and all rights and objections Permittee may have to the form,

content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any unforeseeable event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original

signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. Permittee shall comply with the PSELs according to the following schedule:
   a. On August 1, 2022, the Permittee's PSELs for the following pollutants are:
      i. 20 tons per year for PM10, 240 tons per year for NOx, and 5 tons per year for SO2.
2. Permittee agrees that the only fuel that it may combust in the Boiler 1, Boiler 2 and Boiler 3 at the facility is natural gas, except that it may operate the Boiler 1, Boiler 2, and Boiler 3 on ultra-low sulfur diesel for no more than 48 hours per year.

Willamette Falls Paper Company, Inc. (PERMITTEE)

8/9/2021
Date

Signature

BRIAN KAWEN
Name (print)

PRESIDENT
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

8/9/2021
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE ENVIRONMENTAL QUALITY COMMISSION

OF THE STATE OF OREGON

IN THE MATTER OF: Gas Transmission Northwest LLC Compressor Station #13 Respondent.	))))	FINAL ORDER TO REQUIRE COMPLIANCE WITH ROUND II OF REGIONAL HAZE CASE NO. AQ/RH-HQ-2021-140

I. AUTHORITY

The Department of Environmental Quality (DEQ) issues this Final Order (Notice) pursuant to Oregon Revised Statutes (ORS) 468A.025, and Oregon Administrative Rules (OAR) Chapter 340, Divisions 011 and 223.

II. FINDINGS OF FACT

1. Respondent, Gas Transmission Northwest LLC, operates a natural gas compressor station located at 1/4 mile west of Diamond Lake Junction in Chemult, Oregon (the Facility).

2. On April 9, 1996, DEQ issued Title V Operating Permit No. 18-0096-TV-01 (the Permit) to Respondent.

3. On July 11, 2018, DEQ renewed the Permit.

4. The Permit authorizes Respondent to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. Turbines 13C and 13D at the Facility are emission units, as defined in OAR 340-223-0020(1).

6. On December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, see OAR 340-223-0020(2), at the Facility: 39 tons per year for SO2, 14 tons per year for PM 10, and 244 tons per year for NOx.

7. The Facility is located 30.4 kilometers from the Three Sisters Wilderness Area, which is the nearest Class I Area, see OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

8. On December 31, 2019, DEQ sent a request for information request to Respondent, pursuant to OAR 340-214-0110, to complete a Four Factor Analysis (FFA) for round II of regional haze.

9. On May 12, 2020, Respondent submitted a FFA to DEQ, identifying the cost of controls for the Facility to reduce round II regional haze pollutants.

10. On August 14, 2020, DEQ requested additional information from Respondent regarding their FFA submittal.

11. On January 21, 2021, DEQ concurred with Respondent's findings in the May 12, 2020 FFA that control of NOx by Selective Catalytic Reduction (SCR) is cost effective for Turbines 13C and 13D at the Facility.

12. On August 3, 2021, Respondent submitted a final control cost calculation. DEQ adjusted the calculations pursuant to OAR 340-223-0120(2), OAR 340-223-0120(3) and OAR 340-223-0120(4), which showed that control of NOx by Selective Catalytic Reduction (SCR) is cost effective for Turbines 13C and 13D at the Facility. The final cost calculation is attached as Exhibit A and is incorporated as part of this Order.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 277; d value is 14.1, and ratio of Q divided by d is 19.68.

2. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

3. As of the date of this Order, DEQ and Respondent have not entered into a stipulated agreement and final order under OAR 340-223-0110(2).

4. After review and consideration of all the data submitted by the Facility and based on adjustments by DEQ to Respondent's FFA pursuant to OAR 340-223-0120(2) and (3), DEQ has determined that the Respondent identified control devices that would reduce round II regional haze pollutants with a cost effectiveness below the cost threshold identified in OAR 340-223-0120(4)(a).

IV. ORDER REQUIRING COMPLIANCE WITH ROUND II OF REGIONAL HAZE

Based upon the foregoing FINDINGS OF FACT AND CONCLUSIONS OF LAW, and pursuant to OAR 340-223-0130(1), Respondent is hereby ORDERED TO:

1. By July 31, 2023, Respondent shall submit to DEQ a complete and approvable permit application to incorporate appropriate and required permit conditions for the installation and operation of Selective Catalytic Reduction (SCR) and Continuous Emissions Monitoring System (CEMS) on Turbines 13C and 13D.

2. By July 31, 2024, install a CEMS on Turbines 13C and 13D to measure the emissions of NOx.

   a. Respondent shall demonstrate proper installation of the CEMS following EPA Procedure 1 (see 40 CFR 60, Appendix F, Procedure 1),), Performance Specification 2 (see 40 CFR 60, Appendix B, Performance Specification 2), and DEQ Continuous Monitoring Manual, Rev. 2015; and

   b. Respondent shall submit data collected during testing identified in Section IV.1.a of this Final Order to DEQ for review and to determine if the CEMS was installed correctly and meets the identified quality assurance criteria.

3. By July 31, 2026, install, maintain, and continuously operate SCR on Turbines 13C and 13D with a minimum control efficiency of 90%.

4. Respondent shall not operate Turbines 13C and 13D after August 1, 2026, unless the SCR is properly operating.

V. NOTICE OF RIGHT TO REQUEST A CONTESTED CASE HEARING

You have a right to a contested case hearing on this Order, if you request one in writing. DEQ must receive your request for hearing **within 10 calendar days** from the date you receive this Order. If you have any affirmative defenses or wish to dispute any allegations of fact in this Order, you must do so in your request for hearing, as factual matters not denied will be considered admitted, and failure to raise a defense will be a waiver of the defense. (See OAR 340-011-0530 for further information about requests for hearing.) You must send your request to: **DEQ, Office of Compliance and Enforcement, 700 NE Multnomah Street, Suite 600, Portland, Oregon 97232**, fax it to **503-229-6762** or email it to **DEQappeals@deq.state.or.us**. An administrative law judge employed by the Office of Administrative

Hearings will conduct the hearing, according to ORS Chapter 183, OAR Chapter 340, Division 011 and OAR 137-003-0501 to 0700. You have a right to be represented by an attorney at the hearing, however you are not required to be. If you are an individual, you may represent yourself. If you are a corporation, partnership, limited liability company, unincorporated association, trust or government body, you must be represented by an attorney or a duly authorized representative, as set forth in OAR 137-003-0555.

Active duty Service members have a right to stay proceedings under the federal Service Members Civil Relief Act. For more information contact the Oregon State Bar at 1-800-452-8260, the Oregon Military Department at 503-584-3571, or the nearest United States Armed Forces Legal Assistance Office through http://legalassistance.law.af.mil. The Oregon Military Department does not have a toll free telephone number.

If you fail to file a timely request for hearing, the Order will become a final order by default without further action by DEQ, as per OAR 340-011-0535(1). If you do request a hearing but later withdraw your request, fail to attend the hearing or notify DEQ that you will not be attending the hearing, DEQ will issue a final order by default pursuant to OAR 340-011-0535(3). DEQ designates the relevant portions of its files, including information submitted by you, as the record for purposes of proving a prima facie case.

8/9/2021

Date

Ali Mirzakhalili, Air Quality Administrator
Oregon Department of Environmental Quality

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State of Oregon
Department of Environmental Quality

Notice of Approval Application

Form MD901
Answer Sheet

FOR DEQ USE ONLY	
Permit Number:	Regional Office: ER - AQ Permit Coordinator
Application No:	Check Number:
Date Received:	Amount ($):
Approved (date):	Staff Initials:

1. Source Number: 18-0005-TV-01	
2. Company	**3. Facility Location**
Legal Name: Gilchrist Forest Products LLC	Name: Gilchrist Facility
Ownership type: Corporate	Plant start date: 03/28/1994
Mailing Address: P.O. Box 218	Street Address: #1 Sawmill Road
City, State, Zip Code: Hulett, WY 82720	City, County, Zip Code: Gilchrist, OR 977 Klamath
4. Number of Employees (corporate): 150	Number of Employees (plant site): 150

5. Contact Person	**6. Industrial Classification Code(s)**
Name: Mike Zojonc	SIC: 2421, 4961
Title: Plant Manager	NAICS: 321113, 221330
Phone number: (541) 815-9245	**7. Type of construction/change*:**
Fax number:	Adding ESP device to existing boiler to control PM10 emissions
Email address: mike.zojonc@gilchristfp.com	

8. Signature

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

Mike Zojonc	Plant Manager
Name of Responsible Official	Title of Responsible Official
[signature]	June 8, 2021
Signature of Responsible Official	Date

*Note: This form requires a $720 fee (OAR 340-216-8020 Table 2) for Type 2 Construction. For a description of Construction Types 1 through 4, see OAR 340-210-0225.

Construction information

9.	Will the construction or project establish a new or relocated emissions unit or point at the facility or location? If yes include or attach a plot plan, map, or other map-related image that clearly shows at least the following: • The physical location of the site and proposed construction or change; • The height of the proposed constructed or modified source and emissions point(s) and stack exit points; • A table or scale for distance; • The location of the nearest zoned residential property; and • The location of the nearest zoned commercial property.	Yes ☐ No ☐
10.	Will the construction allow for an increase in production or capacity of the facility? If yes, by how much (include appropriate units or appropriate clarifying details; attach additional pages as necessary):	Yes ☐ No ☑
11.	Will the construction result in: • An increase or decrease any regulated pollutant emissions; or • Cause any new regulated pollutants to be emitted that were not emitted previously? If yes, use the pre and post-construction 'Emissions Data' table below for each regulated pollutant change (increase or decrease) and each new pollutant. See OAR 340-200-0020(134) for a description of regulated pollutants [For the purposes of this form, regulated air pollutant does not include Toxic Air Contaminants])	Yes ☑ No ☐
12.	Are there any requirements applicable to the new construction or modification? If yes, list them by rule citation (attach additional pages as necessary): OAR 340-218-0190 OAR 340-0210-0240	Yes ☑ No ☐

Fill out one of the following (13a or 13b) as appropriate:

13.a **New and unpermitted facilities**: Describe any existing facility or operations on site and the proposed construction.
N/A ☑

13.b **Existing permitted facilities**: Describe the proposed construction or modification and describe the changes to existing processes or activities. N/A ☐

New construction to add an electrostatic precipitator (ESP) air pollution control device to existing boiler to control PM10 emissions. No changes to throughput. The addition of the ESP to the existing boilers system at Gilchrist Forest Products should not have any impact on the normal boiler operation or boiler operational parameters. There will be several ESP operational recommendations to help optimize ESP performance, such as during boiler start-ups waiting until an appropriate boiler exhaust gas temperature is established before energizing the ESP, but the ESP addition itself should not have any impact on boiler operation or performance.

14. Provide a brief description of the production process **and** attach or include a detailed process flow chart or diagram clearly showing new/existing emissions units and any changes to the process flow expected after the construction or modification: N/A ☑

15.	If the construction/project increases the size (i.e., physical footprint) of the facility/operations, a LUCS specific to the change(s) is required (unless the construction is exclusively for the installation of pollution control equipment). All new facilities or additional properties being used require an approved LUCS. If this change requires land use approval, have you attached or included an approved LUCS?	Yes ☐ No ☑ N/A ☐
16.	If the construction involves any new emission unit(s) or changes to existing emission unit(s), series DV200 and EU500 forms are required. Have you attached or included all necessary DV200 and EU500 forms?	Yes ☑ No ☐ N/A ☐
17.	If the construction includes pollution control equipment, series CD300 form(s), manufacturer information, and/or equipment specifications are required. Have you attached or included all necessary CD300 forms and relevant supplemental material?	Yes ☑ No ☐ N/A ☐
18.	Will the construction or project result in any increase or new fuels being used on site? If yes, list the types and approximate quantities expected to be used:	Yes ☐ No ☑
19.	Will the construction or project result in any new or additional refuse generation? If yes: What are the approximate types and amounts? What will be the method of disposal?	Yes ☐ No ☑
If the proposed construction or project has any association with underground storage tanks (or the associated piping), it is the applicant's responsibility to contact the UST program to determine any additional applicable requirements. UST Email: tanks.info@deq.state.or.us UST Phone: 503-229-6652 or 800-742-7878		

Timing of construction:

20.	Date on which contracts are signed, equipment is ordered, or the facility/entity has or will otherwise 'commit' to initiating construction activities	(mm/dd/yyyy) 11/04/2020
21.	Anticipated date of the beginning of physical construction (e.g. breaking ground)	06/21/2021
22.	Anticipated date of construction completion	09/15/2021

23. Include or otherwise attach any information on pollution prevention measures or cross-media impacts you want DEQ to consider in determining applicable control requirements and evaluating compliance methods.

Emissions data: Increases, Decreases, and new pollutants

Pre-and Post-Construction emissions summary data. Note that column (a) will have multiple entries for each emissions unit (one row for each pollutant). Include documentation showing how emissions were calculated.

a. Emissions Point	b. Pollutant	c. Pre-Construction Emissions		d. Post-Construction Emissions	
		Short-term (specify units)	Annual (tons/year)	Short-term (specify units)	Annual (tons/year)
B1-B2	PM	17.0 tons/month	203.9	6.7 tons/month	81.0
B1-B2	PM10	15.6 tons/month	187.2	5.0 tons/month	60.0
B1-B2	PM2.5	9.5 tons/month	114.2	4.4 tons/month	52.5
B1-B2	CO	59.7 tons/month	715.9	59.7 tons/month	715.9
B1-B2	NOx	8.1 tons/month	97.2	8.1 tons/month	97.2
B1-B2	VOC	1.2 tons/month	14.3	1.2 tons/month	14.3
B1-B2	SO2	0.4 tons/month	5.3	0.4 tons/month	5.3

Submit two copies of the completed Notice to the Regional Office listed below for the county where the source is located.

Select County: Klamath

Oregon Department of Environmental Quality

Eastern Region, Air Quality,
475 NE Bellevue Dr., Suite 110
Bend, OR 97701-7415

State of Oregon Department of Environmental Quality

Device\Process Form
Boilers

FORM DV202
Answer Sheet

Facility name: Gilchrist Facility

Permit Number: 18-0005-TV-01

1.	Device name and ID number or label	Wood-fired boilers, B-1 & B-2
2.	Date installation/construction commenced	1939
3.	Date installed	1939
4.	Special control requirements? [if yes, describe]	
5.	Manufacturer	Wickes
6.	Description of boiler, including type of boiler and firing method: The steam plant sources include emission units B-1 and B-2, which are sources of NOx, SO2, VOC and PM10 emissions. Emission units B-1 and B-2 are Dutch oven boilers that were manufactured by Wickes in 1939. Each of these boilers has a steam production capacity of approximately 50,000 pounds per hour (lb/hr) steam. Steam from the two boilers is measured by a single steam flow monitor. B-1 and B-2 are each equipped with a multiclone to control PM emissions and both boilers exhaust through a common stack. A multiclone is type of mechanical separator that contains an array of cyclones used to clean the boiler exhaust.	
7.	Rated design capacity (heat input, Btu/hr)	79,500,000
8.	Maximum steam production rate (lbs/hr)	50,000
9.	Maximum steam pressure (psi)	230
10.	Maximum steam temperature (°F)	520

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Hog Fuel	4.5 tons hog fuel/hr

Print Form

FORM EU501
Answer Sheet

Emissions Unit Summary

Facility name: Gilchrist Facility   Permit Number: 18-0005-TV-01

1.	Emissions Unit name and ID number or label	B-1, B-2
2.	Emissions Unit description	Wood/bark fired boilers
3.	Operating Scenario ID number	PTE

4. Emission devices, processes, and control devices:

Device/process ID(s) from DV2XX	Control Device ID(s) from CD3XX
Wood-fired boilers, B-1 & B-2	ESP

5. Pollutants/Emissions:

Pollutant	PSEL Component from ED605
PM	81.0
PM10	60.0
PM2.5	52.5

Table 6: Applicable Requirements (next page)

State of Oregon Department of Environmental Quality

Pollution Control Device Form
Electrostatic Precipitator

FORM CD301
Answer Sheet

Facility name: Gilchrist Facility Permit Number:

1.	Name				
2.	ID number or label	TBD			
3.	Date installed	2021			
4.	Manufacturer				
5	Model number	2W-091-2422			
6.	Type (wet or dry)	dry			
7.	Rated efficiency (%)	82.22			
8.	Inlet gas pre-treatment?	Multiclone dust collector on each boiler			
9.	Number of fields	2 electrical fields			
10.	Design primary voltage	480 volts			
11.	Design secondary voltage	70,000 volts			
12.	Design primary current	70 amps	94 amps		
13.	Design secondary current	800 MA	1000 MA		
14	Design inlet gas flow rate (acfm)	150,000 ACFM			

Requested annual plant site emission limits

Form ED605A

Facility: Gilchrist Facility

Operating Scenario PTE

Permit Number: 18-0005-TV-0

Emissions Detail:

Emissions Unit ID	Device/ process ID	Pollutant	Annual Production/ Process Rates		Emissions Factor			Emissions
			Rate	Units	Rate	Units	Reference	(tons/yr)
B1-B2	Wood-fired boilers	PM	750,000	lb steam/yr	0.22	lb/Mlb steam	AP-42 derived	81.0
B1-B2	Wood-fired boilers	PM10	750,000	lb steam/yr	0.16	lb/Mlb steam	Wellons Inc.	60.0
B1-B2	Wood-fired boilers	PM2.5	750,000	lb steam/yr	0.14	lb/Mlb steam	AP-42 derived	52.5
*See Attached								
for facility-wide								
PSEL summary								

Requested annual plant site emission limits

Form ED605A

Emissions Unit Summary:

EU ID	Pollutant	Annual Emissions (tons/yr)
B1-B2	PM	81.0
B1-B2	PM10	60.0
B1-B2	PM2.5	52.5

Facility Summary:

Pollutant	Annual Emissions (tons/yr)
PM	121
PM10	81
PM2.5	65
SO2	39
NOx	104
CO	721
VOC	209
GHG	132,300

Summary of requested changes to PSELs

Pollutant	Facility-wide Current PSEL	B1 & B2 Annual Emissions, Tons Current PTE	New PTE	Difference	Facility-wide Post-Construction PSEL
*PM	243	203.9	81.0	122.9	121
**PM_{10}	208	187.2	60.0	127.2	81
***$PM_{2.5}$	126	114.2	52.5	61.7	65
SO_2	39	5.3	5.3	0	39
NO_x	104	97.2	97.2	0	104
CO	721	715.9	715.9	0	721
VOC	209	14.3	14.3	0	209

*PM calculated assuming PM_{10} is 74.1% of total PM — *AP-42 Section 1.6 9/03, Table 1.6-1, Electrostatic Precipitator*

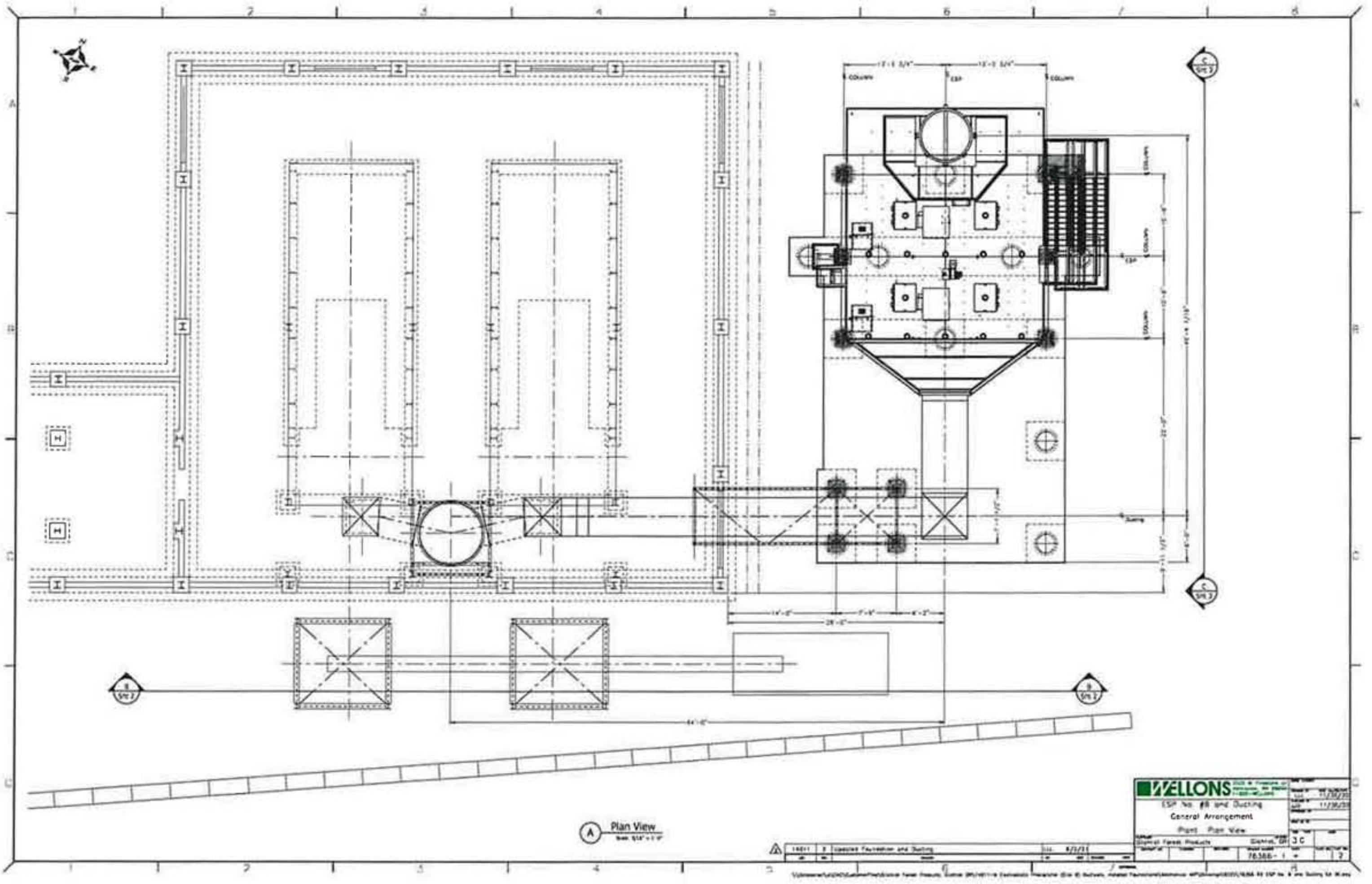
**Emission rate guarantee from manufacturer after installation of ESP — *Wellons, Inc. 2021*

***$PM_{2.5}$ assumed to be 87.5% of PM_{10} — *AP-42 Section 1.6 9/03, Table 1.6-1, Electrostatic Precipitator*

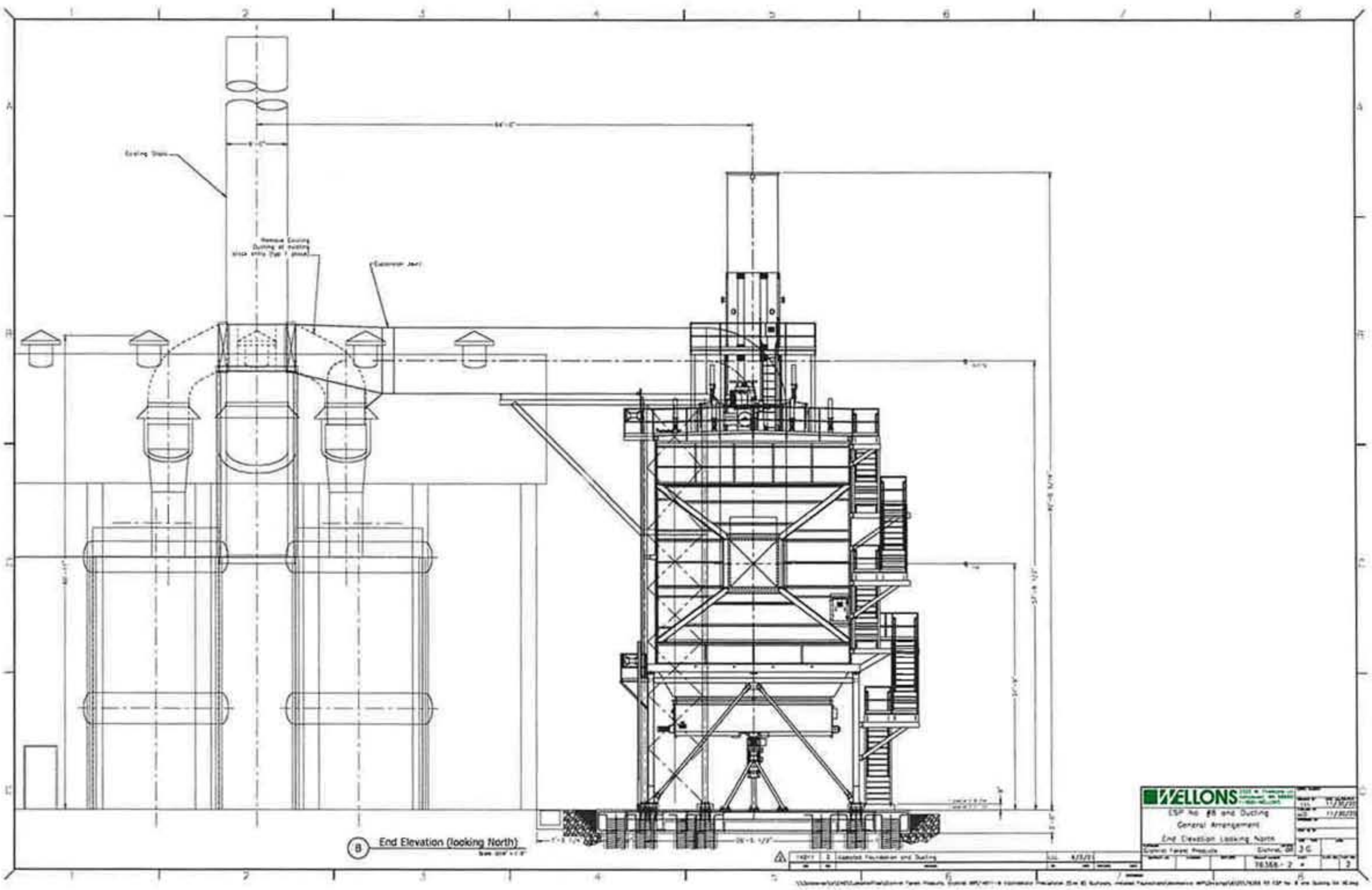
6. Applicable Requirements:

Applicable Requirement Citation	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Current Monitoring Method	Proposed Monitoring Method
340-208-0110 (1)	Visible Air Contaminant Limitations	20% Opacity	Yes	PVEM	PVEM
340-208-0210(2)	Fugitive Emissions	Minimize	Yes	PVEM; REC	PVEM; REC
340-228-0210(1) (a)	Grain Loading Standards	0.2 gr/dscf @ 12% CO2	Yes	CMS; ST; O&M	CMS; ST; O&M; MMP
340-212-0200 - 340–212-0280	residual O2	6% - 13%	Yes	REC	REC
340-212-0200 - 340–212-0280	pressure drop	1" H2O - 4" H2O	Yes	REC	REC
340-220-0120, 340-220-0180	PM10, SO2, NOx, VOC	Approved EFs; production recs	Yes	REC	REC
340-222-0041	PM, SO2, NOx, VOC	PTE	Yes	REC; ST	REC; ST
340-222-0046	PM, PM2.5, PM10, SO2, NOx, CO, VOC, GHG	max production, verified EFs	Yes	REC; ST	REC; ST
340-222-0048	PM,PM10,SO2, NOx,CO,VOC	actual 1977 emissions	Yes	REC; ST	REC; ST
340-222-0048	GHG	actual 2004 emissions	Yes	REC	REC
340-222-0051	PM, SO2, NOx, CO, VOC, GHG	production data, verified EFs	Yes	REC; ST	REC; ST
340-222-0055	PM, SO2, NOx, CO, VOC, GHG	netting basis - PTE	Yes	REC; ST	REC; ST

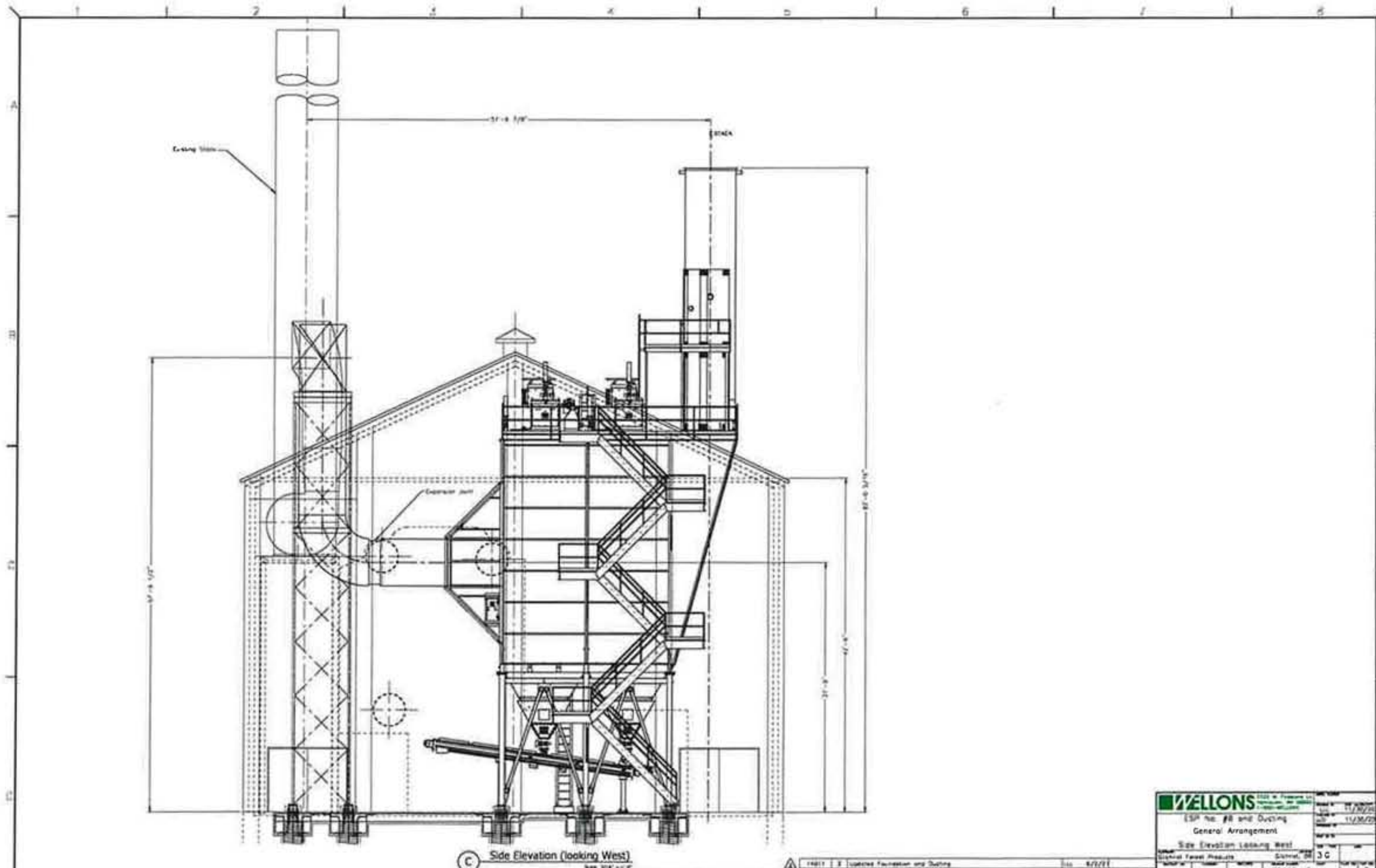
NAD83 UTM Zone 11
June 4, 2021



WELLONS
ESP No. #8 and Ducting
General Arrangement
Plant Plan View
Gilchrist, OR
3 C
78366- 1
Plan View
Upgated Foundation and Ducting



Existing Stack
Remove Existing Ducting at existing stack entry (typ. 1 place)
Expansion Joint
B
End Elevation (looking North)
Updated Foundation and Ducting
WELLONS
ESP No. #8 and Ducting
General Arrangement
End Elevation Looking North
Sierra Pacific Products
78368 - 2



Side Elevation (looking West)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Northwest Pipeline LLC Permittee.	))))	AMENDMENT TO STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 01-0038 AMENDMENT NO. 01-0038-A1

Permittee, Northwest Pipeline LLC, and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee, Northwest Pipeline LLC, operates a natural gas pipeline compressor station located at 18193 Chandler Lane in Baker City, Oregon (the Facility).

2. On May 30, 1997, DEQ issued Title V Operating Permit No. 01-0038-TV-01 (the Permit) to Permittee.

3. On January 12, 2017, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, see OAR 340-223-0020(2): 39 tons per year for SO2, 14 tons per year for PM10, and 542 tons per year for NOx. Specifically, the Permit includes authorization of discharges from the following emissions units, as defined in OAR 340-223-0020(1): _three Cooper GMWA-6 Natural Gas Reciprocating Engines (EU 1 devices C1, C2 and C3), a Cooper GMVH-8 Natural Gas Reciprocating Engine (EU2), a Sellers Natural Gas Boiler (EU4), and a Waukesha Emergency Generator (AUX-1) at the Facility.

6. The Facility is located 40.2 kilometers from the Eagle Cap Wilderness, which is the nearest Class I Area, *see* OAR 340-223-0100(1), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Permittee's Q value is 595; d value is 40.2, and ratio of Q divided by d is 14.8.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Pursuant to OAR 340-223-0110(2), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable reductions of combined plant site emission limits of round II regional haze pollutants to bring the Facility's Q/d below 5.00. which DEQ shall incorporate into a Final Order. As described in Section II, the Final Order would also give the Facility an option to replace EU1 and EU2 by a date certain as an alternative to the plant site emissions reductions. *See* OAR 340-223-0110(2)(A) and (E).

10. DEQ received comments from the U.S. Environmental Protection Agency on the Regional Haze State Implementation Plan, requiring amendments to the SAFO. Additional language is represented in underlined text. Deleted language is represented in strikethrough text.

11. DEQ and Permittee agree to the Amended Stipulated Agreement and Final Order Number 01-0038-A1 (the SAFO Amendment), as indicated by the parties' signatures, below.

I. AGREEMENT

Permittee and DEQ hereby agree that:

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2) and it shall be effective upon the date fully executed.

2. The Permittee is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions schedule or emissions unit replacement schedule and requirements in Section II of this SAFO.

4. The PSEL reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions. If Permittee elects replacement as described in Section II, this provision does not apply.

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit unless an alternative compliance calculation method is required by this SAFO.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-0200(1)(a)(A) or upon permit renewal, whichever if sooner.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO, except as stated in Paragraph I.12 of this SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and DEQ (collectively, the Parties) and the Parties respective successors, agents, and assigns. The undersigned representative of the Parties certifies that he, she, or they are fully authorized to execute and bind the Party to this SAFO. No change in ownership, corporate or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any unforeseen event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must, within 48 hours of the onset of the event or Permittee’s discovery of an event, notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) working days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

The Department of Environmental Quality hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. The Permittee shall comply with the PSELs according to the following schedule:
   a. From August 1, 2022, to July 31, 2023, the Permittee’s PSELs for the following pollutants are:
      i. 5 tons for PM10; 473tons for NOx; and 2 tons for SO2.
   b. From August 1, 2023, to July 31, 2024, the Permittee’s PSELs for the following pollutants are:
      i. 5 tons for PM10; 404 tons for NOx; and 2 tons for SO2.

c. From On August 1, 2024, to July 31, 2025 the Permittee's PSELs for the following pollutants are:

   i. 5 tons for PM10; 335 tons for NOx; and2 tons for SO2.

d. From August 1, 2025, to July 31, 2026 the Permittee's PSELs for the following pollutants are:

   i. 5 tons for PM10; 266 tons for NOx; and 2 tons for SO2.

e. On August 1, 2026, the Permittee's PSELs for the following pollutants are:

   i. 5 tons for PM10; 193 tons for NOx; and 2 tons for SO2.

2. At any point during the phase-out of PSEL, but no later than July 31, 2026, Permittee may request in writing to instead commit to replace EU1 and EU2 at the Facility with new technology to reduce round II regional haze pollutants.

a. Permittee agrees to continue to meet PSELs established in this SAFO that are in effect on July 31, 2021, until the proposed replacement project is completed.

b. DEQ and Permittee shall meet no later than January 1, 2026, to discuss the project and determine what permitting is needed to approve the proposed replacement.

   i. The technology proposed by Permittee for replacement shall meet the emission limits and requirements of the most recent New Source Performance Standard in place at the time of the Permittee submitting a permit application for the project.

   ii. PSELs for round II regional haze pollutants incorporated in the permit modification for the proposed replacement shall be no more than the potential to emit of the proposed replacement, or a Q of 201 tons per year.

   iii. Permittee shall meet all permitting deadlines and provide a complete permit application to DEQ, including any required permitting fees. Both parties will agree to a schedule for permitting of the construction project during this meeting.

c. Permittee shall submit an application for a construction for replacement project in accordance with Section II.2.b.

d. Upon completion of the replacement described in Section II.2.b, Permittee shall not operate EU1and EU2.

e. <u>Permittee shall complete the replacement described in Section II.2.b no later than July 31, 2031.</u>

<u>Northwest Pipeline LLC (PERMITTEE)</u>

DocuSigned by:

Camilo Amezquita

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2/1/2022 | 6:52 AM CST

Date

Signature

Camilo Amezquita

Name (print)

VP GM Northwest Pipeline

Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

DocuSigned by:

Ali Mirzakhalili

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1/31/2022 | 11:32 PM CST

Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Northwest Pipeline LLC Permittee.	))))	AMENDMENT TO STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 03-2729 AMENDMENT NO. 03-2729-A1

Permittee, Northwest Pipeline LLC, and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a natural gas pipeline compressor station located at 15124 S Springwater Road in Oregon City, Oregon (the Facility).

2. On July 1, 1996, DEQ issued Title V Operating Permit No. 03-2729-TV-01 (the Permit) to Permittee.

3. On February 19, 2013, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2): 39 tons per year for SO2, 14 tons per year for PM10, and 344 tons per year for NOx. Specifically, the Permit authorized these discharges from the following emissions units, as defined in OAR 340-223-0020(1): two Ingersoll Rand Reciprocating Internal Combustion Engines (RICE) (EU1), one Solar skid-mounted Turbine (EU6), and one small boiler (EU5), at the Facility.

6. The Facility is located 43.8 kilometers from Mount Hood Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020 (25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 397, d value is 43.8, and ratio of Q divided by d is 9.06.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Pursuant to OAR 340-223-0110(2), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept a federally enforceable requirement to replace the two RICE that comprise EU1 to reduce round II regional haze pollutants from the Facility which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(E).

10. <u>DEQ received comments from the U.S. Environmental Protection Agency on the Regional Haze State Implementation Plan, requiring amendments to the SAFO. Additional language is represented in underlined text. Deleted language is represented in strikethrough text.</u>

11. <u>DEQ and Permittee agree to the Amended Stipulated Agreement and Final Order Number 03-2729-A1 (the SAFO Amendment), as indicated by the parties' signatures, below.</u>

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2), and it shall be effective upon the date fully executed.

2. The Permittee is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions schedule or emissions unit replacement schedule and requirements in Section II of this SAFO.

4. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to OAR 340-218-0200(1)(a)(A) or upon permit renewal, whichever is sooner.

5. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan.

6. Permittee waives any and all rights and objections Permittee may have to the form,

content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO, except as stated in Paragraph I.9 of this SAFO.

7. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

8. This SAFO shall be binding on Permittee and DEQ (collectively, the Parties) and the Parties respective successors, agents, and assigns. The undersigned representative of the Parties certifies that he, she, or they are fully authorized to execute and bind the Party to this SAFO. No change in ownership, corporate or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

9. If any unforeseen event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must, within 48 hours of the onset of the event or Permittee's discovery of an event, notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) working days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by unforeseen circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

10. Facsimile or scanned signatures on this SAFO shall be treated the same as original

signatures.

II. FINAL ORDER

DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. The Permittee shall replace two RICE that comprise EU1 at the Facility with new emissions units to reduce PSELs of round II regional haze pollutants.
   a. DEQ and Permittee shall meet no later than July 1, 2026, to discuss the project and determine what permitting Permittee needs for the replacement.
      i. The technology for replacement shall meet the PSELs and requirements of the most recent New Source Performance Standard (NSPS) in place at the time of the Permittee submitting a permit application for the replacement.
      ii. PSELs for round II regional haze pollutants incorporated in the Permit for the replacement shall be no more than the potential to emit of the replacement, or a Q of 219, whichever is lower.
      iii. Permittee shall meet all permitting deadlines and provide a complete permit application to DEQ, including any required permitting fees. Both parties will agree to a schedule for permitting of the construction project during this meeting.
   b. Permittee shall submit an application for a construction for replacement project in accordance with Section II.1.a.
   c. Upon completion of the replacement described in Section II.1.~~b~~a, Permittee shall not operate EU1.
   d. Permittee shall complete the replacement of described in Section II.1.a no later than July 31, 2031.

DocuSigned by: Northwest Pipeline LLC (PERMITTEE)

Camilo Amezquita

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2/1/2022 | 6:51 AM CST

Date

Signature

Camilo Amezquita

Name (print)

VP GM Northwest Pipeline

Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and ENVIRONMENTAL QUALITY COMMISSION

DocuSigned by:

Ali Mirzakhalili

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1/31/2022 | 11:27 PM CST

Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Cascade Pacific Pulp, LLC Halsey Pulp Mill Permittee.	)))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 22-3501 AMENDMENT NO. 22-3501-A1

Permittee, Cascade Pacific Pulp, LLC, and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee, Cascade Pacific Pulp, LLC, operates a pulp mill located at 30480 American Drive in Halsey, Oregon (the Facility).

2. On March 2, 1998, DEQ issued Title V Operating Permit No. 22-3501-TV-01 (the Permit) to Permittee.

3. On June 30, 2020, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2) at the Facility: 851 tons per year for SO2, 366 tons per year for PM10 and 687 tons per year for NOx.

6. The Facility is located 80.4 kilometers from Three Sisters Wilderness, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 1,904; d value is 80.4, and ratio of Q divided by d is 23.7.

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8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable reductions of combined plant site emission limits of round II regional haze pollutants, remove fuel oil #6 as a fuel for Power Boiler #1 (PB1EU), either ~~and~~ install a low NOx burner or commit to replace PB1EU, which DEQ shall incorporate into a Final Order. See OAR 340-223-0110(2)(b)(C).

10. DEQ received comments from the U.S. Environmental Protection Agency on the Regional Haze State Implementation Plan, requiring amendments to the SAFO. Additional language is represented in underlined text. Deleted language is represented in strikethrough text.

11. DEQ and Permittee agree to the Amended Stipulated Agreement and Final Order Number 22-3501-A1 (the SAFO Amendment), as indicated by the parties' signatures, below.

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(C), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions, control install, and fuel limitations in Section II of this SAFO.

4. The PSEL reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions, except Permittee may retain unassigned emissions not subject to reduction pursuant to OAR 340-222-0055(3)(c).

5. PSELs for this Facility shall not be increased above those established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

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6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to 340-218-0200(1)(a)(A), if applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee modify the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any event occurs that is beyond Permittee's reasonable control and that causes or may cause a delay or deviation in performance of the requirements of this SAFO, Permittee must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence

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of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, work interference caused by pandemic, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. Permittee agrees to not combust fuel oil #6 at any emission unit in the facility by June 30, 2024.
2. By January 31, 2022, Permittee shall conduct source testing for NOx at Power Boiler #1 (PB1EU).
   a. The source test shall be conducted with a steam loading of 80% to 90% designed steam load and the nominal steam load.
   b. Source testing shall adhere to DEQ Source Sampling Manual, Rev. 2018.
3. By March 31, 2024~~December 31, 2022~~, the Permittee shall finalize the design of the low NOx burner to be installed on Power Boiler # 1 (PB1EU).
   a. Permittee shall design the low NOx burner with an objective of achieving a 33% reduction in NOx emissions from Power Boiler #1 (PB1EU). ~~The overall emission reduction with a low NOx burner and the elimination of burning #6 Fuel Oil is anticipated to be up to or greater than 39%, which will be determined by source testing as described in paragraph II.5 and II.6.~~
   b. By March 31, 2025~~December 31, 2023~~, Permittee shall construct and install the low NOx Burner in Power Boiler #1 (PB1EU). Beginning on April 1, 2025,

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Permittee's emissions of NOx from PB1EU shall be at least 20% less than the current emission factor of 282 lb NOx per MM ft3 natural gas and shall be demonstrated to meet this emission reduction through source testing conducted as described in Section II.3.c.

c. By June 30, 2025, Permittee shall conduct source testing for NOx at Power Boiler #1 (PB1EU).

i. The source test shall be conducted with a steam loading of 80% to 90% designed steam load and the nominal steam load.

ii. Source testing shall adhere to DEQ Source Sampling Manual, Rev. 2018.

d. By September 30, 2025, Permittee shall submit to DEQ a report that analyzes the data and information collected in source testing from Section II.3.c of this agreement. The report shall include a proposal from Permittee on a revised emission limit in lb NOx per MM ft3 natural gas for PB1EU. If DEQ determines the testing followed the DEQ Source Sampling Manual, Rev. 2018 requirements, DEQ will use the proposal to establish final emission limit for incorporation into the Permit pursuant to 340-218-0200(1)(a)(A), if applicable, or upon permit renewal.

4. By March 31, 2023, in lieu of complying with the requirements in Section II.3, Permittee may request in writing to instead commit to replace PB1EU at the Facility with new technology to reduce round II regional haze pollutants. If Permittee makes such request to DEQ then:

a. DEQ and Permittee shall meet no later than January 1, 2025, to discuss the project and determine what permitting is needed to approve the proposed replacement and a permit application schedule.

i. The technology proposed by Permittee for replacement shall meet the emission limits and requirements of the most recent New Source

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Performance Standard in place at the time of the Permittee submitting a permit application for the project.

ii. NOx emissions from the proposed replacement meets the emission limits and requirements of the most recent applicable standard in place at the time of the permitting of the new emissions unit pursuant to 340-223-0110(2)(b)(E).

iii. Permittee shall meet all permitting deadlines and provide a complete permit application to DEQ, including any required permitting fees. Both parties will agree to a schedule for permitting of the construction project during this meeting.

b. Permittee shall submit an application for a construction for replacement project in accordance with, and by the deadline established under, Section II.4.a.

c. Upon completion of the replacement, Permittee shall not operate PB1EU.

d. Permittee shall complete the replacement no later than July 31, 2031.

~~4. By December 31, 2023, Permittee shall construct and install the low NOx Burner in Power Boiler #1 (PB1EU).~~

~~5. By March 31, 2024, Permittee shall conduct source testing for NOx at Power Boiler #1 (PB1EU).~~

~~a. The source test shall be conducted with a steam loading of 80% to 90% designed steam load and the nominal steam load.~~

~~b. Source testing shall adhere to DEQ Source Sampling Manual, Rev. 2018.~~

~~6. By June 30, 2024, Permittee shall submit to DEQ a report that analyzes the data and information collected in source testing from Section II.5 of this agreement. The report shall include a proposal from Permittee on revised PSELs. Results from the post installation source test will be used to develop the Plant Site Emission Limit for #1 Power Boiler, which DEQ shall incorporate into the Permit pursuant to 340-218-0200(1)(a)(A), if applicable, or upon permit renewal.~~

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Cascade Pacific Pulp, LLC (PERMITTEE)

1st day of Feb. 2022
Date

Patrick R Rank
Signature

Patrick R. Rank
Name (print)

VP and GM
Title (print)

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

2/1/2022
Date

Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

REGIONAL HAZE FOUR-FACTOR ANALYSIS

COLLINS PRODUCTS, LLC—KLAMATH FALLS FACILITY

Prepared for
COLLINS PRODUCTS, LLC
KLAMATH FALLS FACILITY
June 12, 2020
Project No. 1780.02.01

Prepared by
Maul Foster & Alongi, Inc.
6 Centerpointe Drive, Suite 360, Lake Oswego, OR 97035

MAUL
FOSTER
ALONGI

CONTENTS

ACRONYMS AND ABBREVIATIONS

\$/ton	dollars per ton of pollutant controlled
°F	degrees Fahrenheit
Analysis	Regional Haze Four Factor Analysis
CAA	Clean Air Act
CFR	Code of Federal Regulations
Control Cost Manual	USEPA Air Pollution Control Cost Manual
Collins	Collins Products, LLC
DEQ	Oregon Department of Environmental Quality
ESP	electrostatic precipitator
existing permit	Title V Operating Permit No. 18-0013-TV-01
facility	wood products manufacturing facility located at 6410 Highway 66, Klamath Falls, Oregon 97601
Federal Guidance Document	Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
HAP	hazardous air pollutant
HB	hardboard
MFA	Maul Foster & Alongi, Inc.
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO	nitric oxide
NO_X	oxides of nitrogen
PB	particleboard
PCWP MACT	Plywood and Composite Wood Products Maximum Achievable Control Technology
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
RCO	Regenerative Catalytic Oxidizer
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
USEPA	U.S. Environmental Protection Agency
VOC	volatile organic compound

1 INTRODUCTION

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

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

(1) The cost of control,

(2) The time required to achieve control,

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

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

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

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

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

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

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

1.1 Facility Description

Collins Products, LLC (Collins) owns and operates a wood products manufacturing facility located at 6410 Highway 66, Klamath Falls, Oregon 97601 (the "facility"). The facility produces hardboard (HB) and particleboard (PB). The facility currently operates under Addendum No. 4 to Oregon Title V

Operating Permit No. 18-0013-TV-01 issued by the DEQ on March 14, 2019. The facility is a major source of criteria pollutants and hazardous air pollutants (HAPs). As a result, the facility is subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Plywood and Composite Wood Products, codified in Title 40 Code of Federal Regulations (CFR) Part 63 Subpart DDDD (PCWP MACT). Compliance with the limits and controls associated with this standard require controls that result in significant particulate reductions.

The facility is located just outside the urban growth boundary of Klamath Falls. The urban growth boundary is also the administrative boundary of the Klamath Falls maintenance area for PM_{10} and carbon monoxide. However, the facility is located inside the Klamath Falls nonattainment area for $PM_{2.5}$. The nearest federal Class I Area is the Mountain Lakes Wilderness Area, approximately 24 kilometers northwest of the facility.

1.2 Process Description

1.2.1 Particleboard Plant

Raw materials are delivered to the facility by truck. Raw materials, or furnish (e.g., green and pre-dried wood shavings, sawdust, and chips), are stored, sorted by size, and dried. Dried furnish is separated into core or face grade material. The core and face materials are mixed and blended with formaldehyde free resin, formed into mats, and pressed into boards. Boards are then cooled, sanded, and cut to final product dimensions. Fine particulate emissions generated by all major process equipment, except for the press vent area and two process cyclones, are controlled by fabric filters. Emissions from the press are controlled by a Bio-Reactions BioSystem (biofilter).

1.2.2 Hardboard Plant

The primary processes at the HB plant include raw material receipt, fiber production, mat forming, pressing, baking, humidification, sizing and coating. Raw materials for the HB process include wood by-products of various species. The wood chips are processed through defibrators, where they are blended with resin, producing resinated fibers. Resinated fibers are formed, pressed, baked, humidified and then allowed to cool. Trimmed hardboard siding is coated with a water-based primer coat and oven dried. Emissions from the press and the defibrators are controlled by a combination of cyclones, water sprays, baghouses and a Tri-Mer BioSystem (biofilter).

2 APPLICABLE EMISSION SOURCES

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

After emission rates were tabulated for each emissions unit, estimated emission rates for each pollutant were sorted from the highest emission rate to the lowest. The emission units collectively contributing at least 90 percent of the total facility emissions rate for a single pollutant were identified and selected for the Analysis.

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

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

2.1 Sources of PM_{10} Emissions

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

2.1.1 HB Defibrators/Dryers 1 through 4 (HB01, HB02, HB03, HB04)

Wood chips are processed through four defibrators where they are blended with resin and dried. Process exhaust from HB Defibrators/Dryers 1, 2, and 3 is routed to individual cyclones, followed by multiple in-duct water sprays, followed by a Tri-Mer BioSystem (biofilter). Process exhaust from HB04 is routed to a cyclone, followed by a baghouse, followed by multiple in-duct water sprays, followed by a biofilter. HB Defibrators/Dryers 1, 2, 3 and 4 are subject to PCWP MACT. Because they are already fully controlled sources for PM_{10} emissions, HB01, HB02, HB03 and HB04 will be excluded from further evaluation in the Analysis.

2.1.2 PB Surface Dryers (PB06)

Surface material is conveyed to two flash tube PB surface dryers. Each PB surface dryer is indirectly heated so there are no entrained combustion emissions. The dryer process exhaust is controlled by a downstream baghouse (control device ID PB44).

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

Both PB surface dryers will be excluded from additional analysis for PM control as they are already equipped with best-in-class pollution control technology, which they are required to operate under the federally-enforceable Title V permit. These dryers are also subject to PCWP MACT. Additionally, the surface dryers have potential annual PM_{10} emissions of only 2.54 tons/year. Given the flowrate from this source, MFA is unaware of any additional particulate controls that could be cost effectively applied given the high efficiency of the existing baghouse controls.

2.1.3 HB Cyclone 7 (HB10)

HB cyclone 7 is used to control particulate emissions generated by the former wire negative air system. The exhaust stream enters the cyclone and centrifugal forces are imparted on larger-diameter particles in the conical chamber. The centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of PM at the bottom of the cone. Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone.

2.1.4 HB Cyclone 23 (HB14)

HB cyclone 23 is used to control displaced air during loading and unloading of wood chip storage silos 1, 2 and 3. Silos 1, 2 and 3 store raw wood chips from the chipyard before processing. These raw wood chips have a high moisture content and are assumed to generate minimal PM during loading and unloading processes. Displaced air enters HB cyclone 23 where larger-diameter particles impact the conical chamber and are collected at the bottom of the cone. Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone.

2.1.5 HB Cyclone 27 (HB15)

HB cyclone 27 is used to control particulate emissions generated by the core metering belt shaver system. The fiber exhaust stream enters the cyclone and centrifugal forces are imparted on larger-diameter particles in the conical chamber. The centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of PM at the bottom of the cone. Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone.

2.1.6 HB Bake Oven (HB08) and HB Bake Oven Roof Vents (HB09)

The HB bake oven (HB08) is heated by natural gas-fired combustion and was installed after 1970. The HB bake oven roof vents are situated above emission unit HB08, the hardboard bake oven. Process exhaust from HB08 is routed to the Regenerative Catalytic Oxidizer (RCO) for control of volatile organic compound (VOC) emissions. Entrained filterable and condensable particulate emissions are also combusted in the RCO. and the potential to emit of the RCO is only 2.4 tons/year. Operation of the RCO is required in order to demonstrate compliance with PCWP MACT and the federally-enforceable Title V permit requires continuous parametric monitoring of the device. MFA is unaware of any additional particulate controls that could be cost effectively applied to HB08 given the high efficiency of the existing RCO. Therefore, HB08 will be excluded from additional analysis for PM control.

Racks inside the oven act as a seal during operation. At the end of each cycle as racks are pushed out and new racks are pushed in, fugitive emissions are released to atmosphere through the nearby roof vents (HB09).

2.1.7 PB Core Dryers (PB05)

Core materials are conveyed to two rotary drum PB core dryers. Each PB core dryer is heated by natural gas-fired combustion with a maximum rated design capacity of 10.36 million British thermal units per hour. The moisture content of core material entering the PB core dryers is a maximum of 30 percent moisture and exits with approximately 10 percent moisture. Operating temperature is limited to 600°F. The temperature and moisture limits are required by PCWP MACT and the federally-enforceable Title V permit to minimize the formation of organic emissions that would also form condensable particulate. The combined natural gas-fired burner and dryer process exhaust is controlled by two downstream baghouses (control device IDs PB3 and PB4) which were installed in 1995.

Both PB core dryers will be excluded from additional analysis for PM control as they are already equipped with best-in-class pollution control technology, which they are required to operate under the federally-enforceable Title V permit.

2.1.8 PB Press and Unloader (PB01)

The 14-opening PB press applies heat and pressure to activate the resin in order to bond the wood fibers into solids boards. The PB press produces particleboard ranging between 3/8" to 2-3/16” thick. The PB press was installed after 1970.

Fugitive process exhaust produced by the particleboard presses is routed to the PB biofilter. Testing was conducted by the facility to determine the PM, PM_{10} and $PM_{2.5}$ emission reductions and PM emission reduction credits were allowed based on the results. PB01 is subject to PCWP MACT and is required by the federally-enforceable Title V permit to operate the PB biofilter in order to maintain compliance with that standard. In addition, Addendum No. 3, dated April 6, 2018, to Title V Operating Permit expressly requires that the PB biofilter be operated and maintained as a particulate emissions control device.

2.1.9 PB Trim Saw (PB03)

The PB trim saw is used to trim particleboard sides and ends to final product dimensions. Uncontrolled fugitive particulate emissions are release to atmosphere by nearby roof vents.

2.1.10 PB Cyclone 24 (PB24)

Wood dust from the board trimming process are pneumatically conveyed to process PB cyclone 24, which separates larger-diameter particles from the exhaust stream. Centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of the larger-diameter wood dust at the bottom of the cone. Collected materials are pneumatically conveyed to PB cyclone 15, which dumps collected material to the reclaim storage pile. Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone.

2.1.11 Cyclones with Secondary Filters (PB10)

The cyclones with secondary filters handle sanderdust from the board finishing area in the PB plant. Sanderdust from the board finishing process is pneumatically conveyed to PB cyclone 10, which separates larger-diameter particles from the exhaust stream. The exhaust stream exiting the top of PB cyclone 10 is routed to a downstream baghouse for control of fine particulate emissions. The particleboard cyclones with secondary filters will be excluded from additional analysis for PM control as they are already equipped with best-in-class pollution control technology, which they are required to operate under the federally-enforceable Title V permit. Additionally, PB10 has potential annual PM_{10} emissions of only 2.98 tons/year. Given the flowrate from this source, MFA is unaware of any additional particulate controls that could be cost effectively applied given the high efficiency of the existing baghouse controls.

2.2 Sources of SO_2 Emissions

A summary of the selected emission units and associated SO_2 emission rates to be evaluated in the Analysis is presented in Table 2-2 (attached). The Title V review report (page 37 of 92) still identifies the facility as having the potential to emit 49.3 tons/year of SO_2 from PB05 based on the combustion of 1.39 million gallons of fuel oil annually. In fact, the fuel oil infrastructure has been removed and as the Title V review report (page 39 of 92) shows, the last time that fuel oil was combusted in the PB core dryers was in 2000 when 333 gallons were consumed. As the PB core dryers no longer have the capacity to burn fuel oil and are now only capable of burning natural gas, the potential to emit equals the device's maximum capacity to emit SO_2 while burning natural gas. References to fuel oil combustion by the PB core dryers will be removed as part of the permit renewal currently underway. The PB core dryers have a combined maximum heat input of 20.7 MMBtu/hr which limits the dryers to an SO_2 potential to emit of 0.5 tons/year. Given that the reductions for small sources likely would not improve visibility and would not be cost effective, these activities will not be evaluated further in the Analysis.

2.3 Sources of NO_X Emissions

A summary of the selected emission units and associated NO_X emission rates to be evaluated in the Analysis is presented in Table 2-3 (attached). As noted in Section 2.2, the PB core dryers no longer have the ability to burn fuel oil. The PB core dryers have a combined maximum heat input of 20.7

MMBtu/hr which limits the dryers to a NOx potential to emit of 8.9 tons per year when burning natural gas.

Because of the limited combustion sources at the facility, the Title V permit contains a generic PSEL for NOx of 39 tons/year. Actual emissions are substantially lower (6.9 tons in 2019). Given that the reductions for small sources likely would not improve visibility and would not be cost effective, these activities will not be evaluated further in the Analysis.

2.4 Emissions Unit Exhaust Parameters

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

3 REGIONAL HAZE FOUR FACTOR ANALYSIS METHODOLOGY

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

3.1 Step 1: Determine Emission Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

Section 2 details the method for determining the emission units and emission rates to be used in the Analysis. Potential to emit emission rates were obtained from the existing permit review report.

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

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

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

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

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

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

3.5 Step 5: Characterize Energy and non-Air Environmental Impacts (Statutory Factor 3)

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

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

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

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

4 PM10 ANALYSIS

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

4.1 Step 1 – Determine PM_{10} Control Measures for Consideration

4.1.1 Baghouse

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

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

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

4.1.2 Wet Venturi Scrubber

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

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

The facility operates a closed-loop wastewater system for its existing process water, stormwater and sanitary water. The system currently operates at maximum capacity for the management of wastewater and wet sludge and is unable to accommodate any additional wastewater streams. Additionally, since there are no municipal water treatment plants approved to accept industrial wastewater effluents, there are no off-site options for wastewater management. Therefore, wet control technologies are considered infeasible for the facility and will not be evaluated further in the Analysis.

4.1.3 Electrostatic Precipitator

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

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

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern as they reduce air pollution. Use of wet ESPs generates a wastewater and wet sludge effluent that requires treatment and subsequent disposal. As noted in Section 4.1.2, the wastewater system at the facility currently operates at maximum capacity and is unable to accommodate any additional wastewater streams. Therefore, wet ESPs are considered infeasible for the facility and will not be evaluated further in the Analysis.

The use of dry ESPs with suspended particulates is a safety hazard as the particulate dust may explode if exposed to an ignition source such as spark between the charged ESP plates. Thus, based on the low moisture content of the exhaust streams, and the facility's concerns regarding potential fire or explosion hazards, dry ESPs are considered infeasible for the facility and will not be evaluated further in the Analysis.

4.2 Step 2 – Selection of Emissions

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

4.3 Step 3 – Characterizing the Cost of Compliance

Table 4-2 (attached) presents the detailed cost analyses of the technically feasible PM_{10} control technologies included in the Analysis. A summary of the cost of compliance, expressed in $/ton, is shown below in Table 4-1:

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

Emissions Unit	Emissions Unit ID	Cost of Compliance ($/ton)
		Baghouse
Particleboard Press and Unloader	PB01	36,664
Trim Saw Vent	PB03	24,639
Cyclone PB24	PB08	24,763
Bake Oven Roof Vent	HB09	26,985
Cyclone HB7	HB10	25,942
Cyclone HB23	HB14	25,782
Cyclone HB27	HB15	49,642

4.4 Step 4 – Characterizing the Time Necessary for Compliance

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

4.5 Step 5 – Characterizing the Energy and non-Air Environmental Impacts

4.5.1 Energy Impacts

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

4.5.2 Environmental Impacts

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

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

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

4.6 Step 6 – Characterize the Remaining Useful Life

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

5 SO_2 ANALYSIS

SO_2 emissions from the plant are negligible. Given the reductions for a small source likely would not improve visibility and would not be cost effective, these activities will not be evaluated further in the Analysis.

6 NO_X ANALYSIS

Because of the limited combustion sources at the facility, the Title V permit contains a generic PSEL for NOx of 39 tons/year. Actual emissions are substantially lower (6.9 tons in 2019). Given that the reductions for small sources likely would not improve visibility and would not be cost effective, these activities will not be evaluated further in the Analysis.

7 CONCLUSION

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

Based on the costs described above for the controls under consideration, there does not appear to be any control device that, on a dollar per ton of pollutant-controlled basis, would be considered cost effective. In addition, given the extensive pollution controls already in place at the facility, any additional controls would result in limited visibility improvement. In the absence of significant visibility improvement, it would not be appropriate to require investment in additional controls at a wood products facility in an economically challenged part of the state.

LIMITATIONS

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

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

TABLES

Table 2-1
PM_{10} Evaluation for Regional Haze Four Factor Analysis
Collins Products, LLC. - Klamath Falls, Oregon

Emission Units [(1)]	Emission Unit ID(s)	Current PM_{10} Control Technology [(1)]	Pollution Control Device ID	Annual PM_{10} Emissions [(2)] (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls To Be Evaluated
Defibrators/Dryer (x 3)	HB01-HB03	Cyclone, Biofilter	HB50 (Biofilter)	33.5	No	Sources are already controlled. Process exhaust is routed to individual cyclones, followed by in-duct water sprays, followed by a biofilter.	--
Core Dryers	PB05	Baghouses	PB3, PB4	30.6	No	Sources are already equipped with best-in-class controls. Process exhaust from the core dryers is routed to two downstream baghouses (PB3 and PB4).	--
Particleboard Press and Unloader Area	PB01	Biofilter	PB45	16.1	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Trim Saw Vent	PB03	--	--	11.9	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclone PB24	PB08	--	--	11.1	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Bake Oven Roof Vents	HB09	--	--	10.8	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclone HB7	HB10	--	--	8.66	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclone HB23	HB14	--	--	8.71	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclone HB27	HB15	--	--	4.52	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclones w/ Secondary Filters	PB10	Bagfilters	PB35, PB36, PB37	2.98	No	Sources already are equipped with best in class controls.	--
Surface Dryers	PB06	Baghouse	PB44	2.54	No	Sources already are equipped with best in class controls.	--
All Other Emission Units	Varies	Varies per Emission Unit	--	13.4 [(3)]	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:

PM_{10} = Particulate matter with an aerodynamic diameter of 10 microns or less.

REFERENCES:

(1) Information from the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

(2) Information from the Review Report for the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

(3) The annual PM_{10} emissions estimate of 13.4 tons per year represents the sum total of annual PM_{10} emissions from all emission units collectively comprising less than 10% of the total facility PM_{10} emissions rate.
The maximum annual PM_{10} emissions estimate, from a single emissions unit within this grouping, is only 2.44 tons per year.

Table 2-2
SO_2 Evaluation for Regional Haze Four Factor Analysis
Collins Products, LLC. - Klamath Falls, Oregon

Emission Units (1)	Emission Unit ID(s)	Current SO_2 Control Technology (1)	Annual SO_2 Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls To Be Evaluated
Aggregate Insignificant Activities	Varies	--	1.00	No	Emission controls for 1 ton/yr would not improve visibility and would not be cost effective.	--
Core Dryers	PB05	--	0.50	No	PB Core Dryers no longer have the ability to burn fuel oil and only have the potential to emit 0.5 tons/yr of SO_2 when burning natural gas. Emission controls would not improve visibility and would not be cost effective.	--
All Other Emission Units	Varies	--	0.046	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:
SO_x = Sulfur dioxide

REFERENCES:
(1) Information from the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.
(2) Information from the Review Report for the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

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Table 2-3
NO_X Evaluation for Regional Haze Four Factor Analysis
Collins Products, LLC. - Klamath Falls, Oregon

Emission Units (1)	Emission Unit ID(s)	Current NO_X Control Technology (1)	Annual NO_X Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls To Be Evaluated
Core Dryers	PB05	--	8.88	No	PB Core Dryers no longer have the ability to burn fuel oil and only have the potential to emit 8.88 tons/yr of NO_x when burning natural gas. Emission controls would not improve visibility and would not be cost effective.	--
Hardboard Coating Ovens	HB17	--	6.90	Yes	Emission controls would not improve visibility and would not be cost effective.	--
Bake Oven	HB08	--	3.52	Yes	Emission controls would not improve visibility and would not be cost effective.	--
All Other Emission Units	Aggregate Insignificant	--	1.00	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:
NO_x = Oxides of nitrogen

REFERENCES:
(1) Information from the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.
(2) Information from the Review Report for the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

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Table 2-4
Emissions Unit Input Assumptions and Exhaust Parameters
Collins Products, LLC. - Klamath Falls, Oregon

Emissions Unit ID	Emissions Unit Description	Control Evaluation Proposed? (Yes/No)			Heat Input Capacity (MMBtu/hr)	Exhaust Parameters		
						Exit Temperature (°F)	Exit Flowrate	
		PM_{10}	NO_X	SO_2			(acfm) [1]	(scfm)
HB01 - HB03	Defibrators/Dryers	Yes	No	No	--	199 [1]	56,208	39,029 [a]
HB08	Bake Oven	No	Yes	No	10.6 [1]	271 [1]	28,879	18,056 [1]
HB09	Bake Oven Roof Vents	Yes	No	No	--	70.6 [1]	19,364	16,712 [1]
HB10	Cyclone HB7	Yes	No	No	--	70 [2]	5,827	5,031 [a]
HB14	Cyclone HB23	Yes	No	No	--	70 [2]	5,827	5,031 [a]
HB15	Cyclone HB27	Yes	No	No	--	70 [2]	5,827	5,031 [a]
HB17	Hardboard Coating Ovens	No	Yes	No	38.6 [1]	271 [1]	28,879	18,083 [a]
PB01	Particleboard Press and Unloader Area	Yes	No	No	--	77.7 [1]	78,862	67,165 [1]
PB03	Trim Saw Vent	Yes	No	No	--	220 [1]	19,364	13,027 [a]
PB05	Core Dryers	No	No	No	20.7 [3]	141 [1]	15,160	10,641 [1]
PB08	Cyclone PB24	Yes	No	No	--	70 [2]	15,970	13,788 [a]

NOTES:

acfm = actual cubic feet per minute.

°F = degree fahrenheit

ft/sec = feet per second.

MMBtu/hr = million British thermal units per hour.

NO_x = Oxides of nitrogen

PM_{10} = Particulate matter with an aerodynamic diameter of 10 micron or less

scfm = standard cubic feet per minute.

SO_x = Sulfur dioxide

(a) Exit flowrate (scfm) = (exit flowrate [acfm]) x (1 - [6.73E-06] x [facility elevation above sea level {ft}])$^{5.258}$ x (530) / (460 + [exit temperature {°F}])

Facility elevation above sea level (ft) = 4,094 (4)

REFERENCES:

(1) Data provided by Collins Products, LLC.

(2) Assumes an ambient temperature of 70°F.

(3) Information from the Review Report for the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

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

Table 3-1
Operating and Maintenance Rates
Collins Products, LLC. - Klamath Falls, Oregon

Parameter	Value	(units)	
FACILITY OPERATIONS			
Annual Hours of Operation	8,760	(hrs/yr)	(1)
Annual Days of Operation	365	(day/yr)	(1)
Daily Hours of Operation	24.0	(hrs/day)	(1)
UTILITY COSTS			
Electricity Rate	0.064	($/kWh)	(2)
Natural Gas Rate	5.22	($/MMBtu)	(2)
Water Rate	10.0	($/Mgal)	(2)
Compressed Air Rate	0.004	($/Mscf)	(2)
Landfill Disposal Fee	74.0	($/ton)	(2)
LABOR COSTS			
Maintenance Labor Rate	25.18	($/hr)	(2)
Operating Labor Rate	18.63	($/hr)	(2)
Supervisory Labor Rate	35.00	($/hr)	(2)
Typical Shifts per Day	3.00	(shifts/day)	(2)

NOTES:

Mgal = thousand gallons.

MW-hr = megawatt-hour.

scf = standard cubic feet.

REFERENCES:

(1) Assumes continuous annual operation.

(2) Data provided by Collins Products, LLC.

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Table 4-2
Cost Effectiveness Derivation for Baghouse Installation
Collins Products, LLC. - Klamath Falls, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters		Pollutant Removed by Control Device (a) (tons/yr)	Operating Parameter	
		Exhaust Flowrate (1) (acfm)	PM_{10} Annual Emissions Estimate (2) (tons/yr)		Electrical Requirements (3) (kW)	Number of Filter Bags Required (4)
HB09	Bake Oven Roof Vents	19,364	10.8	10.7	88.7	250
HB10	Cyclone HB7	5,827	8.66	8.57	39.5	82
HB14	Cyclone HB23	5,827	8.71	8.63	39.5	82
HB15	Cyclone HB27	5,827	4.52	4.47	39.5	82
PB01	Particleboard Press and Unloader Area	78,862	16.1	15.9	306.5	987
PB03	Trim Saw Vent	19,364	11.9	11.7	88.7	250
PB08	Cyclone PB24	15,970	11.1	11.0	76.8	208

Emissions Unit ID	Emissions Unit Description	Direct Costs			Total Indirect Costs (d)	Total Capital Investment (e)	Capital Recovery Cost				Direct Annual Costs								Total Indirect Annual Costs (o)	Total Annual Cost (p)	Annual Cost Effectiveness (q)
		Purchased Equipment Cost		Total Direct Cost (c)			Control Device (f)	Replacement Parts			Operating Labor		Maintenance		Utilities			Total Direct Annual Costs (14)			
		Basic Equip./Services Cost (4)	Total (b)					Filter Bag Cost (4)	Bag Labor Cost (h)	Filter Bag (i)	Operator Cost (j)	Supervisor Cost (k)	Labor Cost (j)	Material Cost (14)	Electricity Cost (l)	Compressed Air Cost (m)	Landfill Cost (n)				
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D	C_B	C_L	CFC_B	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
HB09	Bake Oven Roof Vents	$106,809	$126,034	$219,300	$56,715	**$276,015**	$21,681	$3,763	$1,574	$1,581	$40,800	$6,120	$27,572	$27,572	$50,053	$40,711	$793	$195,202	$72,279	**$289,162**	**$26,985**
HB10	Cyclone HB7	$76,367	$90,113	$156,796	$40,551	**$197,347**	$15,502	$1,233	$516	$518	$40,800	$6,120	$27,572	$27,572	$22,293	$12,251	$634	$137,760	$69,132	**$222,394**	**$25,942**
HB14	Cyclone HB23	$76,367	$90,113	$156,796	$40,551	**$197,347**	$15,502	$1,233	$516	$518	$40,800	$6,120	$27,572	$27,572	$22,293	$12,251	$638	$137,764	$69,132	**$222,398**	**$25,782**
HB15	Cyclone HB27	$76,367	$90,113	$156,796	$40,551	**$197,347**	$15,502	$1,233	$516	$518	$40,800	$6,120	$27,572	$27,572	$22,293	$12,251	$331	$137,456	$69,132	**$222,090**	**$49,642**
PB01	Particleboard Press and Unloader Area	$240,608	$283,917	$494,016	$127,763	**$621,779**	$48,841	$14,883	$6,213	$6,249	$40,800	$6,120	$27,572	$27,572	$172,874	$165,799	$1,177	$448,163	$86,109	**$583,113**	**$36,664**
PB03	Trim Saw Vent	$106,809	$126,034	$219,300	$56,715	**$276,015**	$21,681	$3,763	$1,574	$1,581	$40,800	$6,120	$27,572	$27,572	$50,053	$40,711	$869	$195,278	$72,279	**$289,238**	**$24,639**
PB08	Cyclone PB24	$99,176	$117,028	$203,629	$52,663	**$256,292**	$20,132	$3,129	$1,309	$1,315	$40,800	$6,120	$27,572	$27,572	$43,324	$33,575	$815	$181,092	$71,490	**$272,714**	**$24,763**

Table 4-2
Cost Effectiveness Derivation for Baghouse Installation
Collins Products, LLC. - Klamath Falls, Oregon

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

Baghouse control efficiency (%) =	99.0	(4)

(b) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (5).
(c) Total direct cost ($) = (1.74) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (5).

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

(d) Total indirect cost ($) = (0.45) x (total purchased equipment cost [$]); see reference (5).
(e) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (5).
(f) Control device capital recovery cost ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (7)

Control device capital recovery factor =	0.0786	(g)

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

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

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

total time required to change one bag (min/bag) =	15	(12)
Maintenance labor rate ($/hr) =	25.18	(13)

(i) Filter bag capital recovery cost ($) = ([initial filter bag cost {$}] x (1.08) + [bag replacement labor cost {$}]) x (filter bag capital recovery factor); see reference (13).

Filter bag capital recovery factor =	0.2804	(g)

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

Operating labor hours per shift [hrs/shift) =	2	(13)
Maintenance labor hours per shift [hrs/shift) =	1	(13)
Shifts per day (shifts/day) =	3	(13)
Annual days of operation (days/yr) =	365	(13)
Operator labor rate ($/hr) =	18.63	(13)
Maintenance labor rate ($/hr) =	25.18	(13)

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (13).
(l) Annual electricity cost ($) = (electricity rate [$/kWh]) x (total power requirement [kWh]) x (annual hours of operation [hrs/yr])

Electricity rate ($/kWh) =	0.064	(13)
Annual hours of operation (hrs/yr) =	8,760	(13)

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

Compressed air cost ($/Mscf) =	0.0040	(13)
Annual hours of operation (hrs/yr) =	8,760	(13)

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

Landfill disposal rate ($/ton) =	74.00	(13)

(o) Total indirect annual cost ($) = (0.60) x ([operator cost {$}] + [superviser cost {$}] + [maintenance cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]); see reference (13).
(p) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$]) + (control device capital recovery cost [$])
(q) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:
(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. In the quote, costs and equipment requirements for three differently sized baghouses (5,000 cfm, 20,000 cfm, and 50,000 cfm) are presented. For the smallest exhaust flowrate above (MC4), these quoted data was scaled using a ratio. All other costs/data were scaled and obtained using tread line formulas. It is important to note that the quoted costs do not include the costs associated with taxes, installation of equipment, all concrete work (excavation, engineering, plumbing, electrical), building/foundation upgrades, and permitting or licensing.
(4) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-025) for baghouse (fabric filter), pulse-jet cleaned type issued July 15, 2003. Assumes minimum typical new equipment design efficiency.
(5) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See Table 1.9 "Capital Cost Factors for Fabric Filters." The 1.18 factor includes instrumentation, sales tax, and freight.
(6) Conservatively assumes no costs associated with site preparation or building requirements.
(7) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(8) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(9) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(10) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.2.
(11) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. Typical bag filter life is 4 years.
(12) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.1.4.

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

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

REGIONAL HAZE – FOUR FACTOR ANALYSIS

Columbia Forest Products
Klamath Falls, Oregon

June 2020

Regional Haze – Four Factor Analysis

Prepared for:
Columbia Forest Products
4949 Highway 97
Klamath Falls, Oregon 97603

This document has been prepared by SLR International Corporation (SLR). The material and data in this report were prepared under the supervision and direction of the undersigned.

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CONTENTS

ATTACHMENTS

ACRONYMS, ABBREVIATIONS AND TERMS

4FA	Four Factor Analysis
BACT	Best Available Control Technology
Btu	British thermal unit
CFP	Columbia Forest Products
CFR	Code of Federal Regulations
CO_2	Carbon dioxide
DEQ	Department of Environmental Quality
EPA	Environmental Protection Agency
ESP	Electrostatic precipitator
FGR	Fuel gas recirculation
GHG	Greenhouse gas
HAP	Hazardous air pollutants
IMPROVE	Interagency Monitoring of Protected Visual Environments
LAER	Lowest Achievable Emission Rate
LNB	Low NO_X burner
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSR	New Source Review
OFA	Overfire air
O&M	Operation and maintenance
PM	Particulate Matter
PM_{10}	Coarse Particle Matter or Particulate Matter; with an aerodynamic diameter of 10 microns or less
PSEL	Plant Site Emission Limit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
tpy	Tons per year

1. INTRODUCTION

This Regional Haze Four Factor Analysis (4FA) was prepared on behalf of Columbia Forest Products Klamath Falls (the Facility) located at 4949 Highway 97 South, Klamath Falls, Oregon. The Facility manufactures plywood under Title V operating permit number 18-0014-TV-01. The Oregon Department of Environmental Quality (DEQ) identified the Facility as a significant source of regional haze precursor emissions to a Class I area in Oregon, thus triggering the need for a 4FA under the regional haze program.

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.

Data from the Environmental Protection Agency (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 less than 10-micron in diameter (PM_{10}).

The nearest Class I areas to the Facility are the Mountain Lakes Wilderness, located 13 miles northwest, and Crater Lake National Park, located about 40 miles north.

This 4FA provides a detailed evaluation of the Facility emission units that contribute emissions of precursor compounds. The purpose of the analysis is to determine whether additional specific control measures are reasonable for the control of precursor compounds. The four factors considered in this analysis 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.

1.1 FACILITY OVERVIEW

The Facility is a hardwood and veneer plywood mill (NAICS codes 321211 and 221330) located just south of the City of Klamath Falls, Oregon, along the northwest bank of the Klamath River. The Facility operates under Title V operating permit number 18-0014-TV-01 issued by the Oregon DEQ on September 26, 2017 and which expires on October 1, 2022.

The Facility is required to have a Title V air operating permit because it has potential to emit more than 100 tons per year of a criteria pollutant. The Facility has taken a synthetic minor permit limit to limit their potential to emit hazardous air pollutants (HAP) to less than the major HAP source levels.

The main product of the plant is 4' x 8' x 3/4" thick hardwood faced panels. The hardwood veneer is brought in from other locations in a pre-dried condition. Most of the core panels consist of plywood manufactured from white fir veneer which is processed from the raw logs in the Facility. Some of the core panels to which the hardwood face veneer is glued are brought in from elsewhere and consist of veneer core or composite panels (e.g., medium density fiberboard) manufactured by other companies.

The raw logs are brought in by truck and stored until needed. The raw logs are then debarked in a ring de-barker. After the de-barker, the logs are cut to length by a set of large circular chop saws. These sections of peeler logs, called blocks, are transported by conveyor and automatically sorted into bins. The waste trim pieces of the logs known as lily pads are transported to the lily pad chipper. Front end loaders place the blocks into the vats (steam conditioning chests). The blocks are conditioned with hot water and steam to make them suitable for turning on a lathe to peel off veneer.

After conditioning, the blocks are placed on the in-feed conveyors to the lathe. At the lathe, the veneer ribbon travels down a conveyor, through a clipping station where defects are clipped out and to an automatic stacker which sorts the veneer pieces by size and moisture content. Veneer pieces are also pulled from the line after the stacker at the green chain. Reject pieces of veneer and trim pieces are carried by conveyor to the veneer chipper. The block cores left over after peeling are conveyed to the sorter. Some are stockpiled to be trucked offsite and sold while others are chipped for fuel.

The stacks of green veneer are transported by forklift to the B plant. The green veneer is dried in one of the two dryers to less than 24% moisture content. Veneer pieces which test out above the moisture specification after exiting the dryers are either re-dried or stored until they meet the required dryness specification. The two dryers are the Keller #1 & #2 (fired by natural gas).

The dried veneer is worked into solid sheets with a minimum of voids by plugging defects or edge gluing smaller pieces with hot melt glue.

The next activity in the plywood manufacturing process is that of spreading the glue on the veneer sheets, orienting the grain direction of the core veneers at right angles to each other, then placing the hardwood face veneers at the top and bottom of each assembly. After gluing, the stack of laid-up panels is initially placed in a cold press, then put into one of three hot presses.

The plywood panels exiting hot presses are moved to the panel saw for trimming. Any voids in the faces are filled with putty by hand in the patch line. Some oak faced panels are conditioned to prevent staining.

After the patch line, the panels are run through the sander, then inspected and packaged for shipment. The sander is ventilated by a separate sander dust ventilation system. Some of the panels have a coating applied in a UV coating line.

The byproducts or "residuals" are handled as four separate material streams: Wood chips, hogged fuel (mostly bark), plytrim, and sander dust. These residual streams are transported by such means as mechanical conveyor, truck load out bin, and pneumatic transfer through cyclones (C1 & C2). Steam for the presses and the vats is provided by the north and south boilers.

1.2 NESHAPs

The Facility boilers are subject to 40 CPR Part 63, Subpart JJJJJJ, *National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers Area Sources*. The boilers are subject to two work practice requirements: conduct a one-time energy assessment and conduct a boiler tune-up every 2 years.

The Wood Building Products (surface coating) NESHAP (40 CFR, Part 63, Subpart QQQQ) that was promulgated on May 28, 2003 is applicable to the UV coating line.

In 2007, the Facility demonstrated that it is no longer a major source of HAPs, so the NESHAPs for Plywood and Composite Wood Products (40 CFR, Part 63, Subpart DDDD) and Industrial, Commercial and Institutional Boilers and Process Heaters (40 CFR, Part 63, Subpart DDDDD) at major sources are not applicable.

1.3 PRECURSOR COMPOUND EMISSIONS

The Facility emits three types of regional haze precursor compounds: nitrogen oxides, sulfur dioxide, and particulate matter less than 10 microns in diameter. Facility-wide emissions of these compounds for 2017 and the Facility's potential to emit for each compound are presented in Table 1-1. Detailed emission calculations are provided in Attachment B.

Table 1-1. Actual and Permitted Facility-wide Emissions for CFP Klamath Falls

Emission Unit	2017 Actual Emissions (tons per year)				Permitted Emissions (tons per year)			
	NO_X	SO_2	PM_{10}	Total Quantity	NO_X	SO_2	PM_{10}	Total Quantity
South Boiler	37.59	1.01	36.18	74.78	45.55	1.23	43.84	90.62
North Boiler	0.0	0.0	0.0	0.0	6.48	0.25	5.28	12.01
Veneer Dryers	5.03	--	15.09	20.12	9.75	--	29.26	39.01
Plywood Press	--	--	2.29	2.29	--	--	3.26	3.26
Storage Pile	--	--	1.72	1.72	--	--	2.44	2.44
Material Handling	--	--	1.92	1.92	--	--	2.73	2.73
Facility Wide	**43.18**	**1.02**	**57.71**	**101.91**	**65.0**	**39.0***	**87.0**	**191.0**

*Generic Plant Site Emission Limit (PSEL)

The two boilers, two veneer dryers, three press vents, a hog-fuel storage pile, and material handling equipment emit precursor compounds. The precursor compound emissions from each emission unit and the existing pollution control equipment are summarized in Table 1-2.

Table 1-2. Summary of Precursor Compounds Emitted by Emission Unit

Emission Unit	Emission Unit ID	Precursor Compounds Emitted	Installation Date	Existing Pollution Control Equipment
North Boiler	BLR-N	PM_{10}, SO_2, NO_X	1939	NA
South Boiler	BLR-S	PM_{10}, SO_2, NO_X	1944	Multiclone
Keller Dryer #1 (east)	V-N	PM_{10}, SO_2, NO_X	1984	NA
Keller Dryer #2 (west)	V-N	PM_{10}, SO_2, NO_X	1989	NA
Press Vent 1	PV-1	PM_{10}	1983	NA
Press Vent 2	PV-2	PM_{10}	Before 1978	NA
Press Vent 3	PV-3	PM_{10}	Before 1978	NA
Storage Piles	SP	PM_{10}	NA	NA
Material Handling	MH	PM_{10}	NA	Cyclone, Baghouse

The emissions of two boilers, two veneer dryers, and three press vents comprise 98.7% of NO_X, 99% of SO_2, 93% of PM_{10} emissions compared to 2017 facility-wide emissions. Therefore, only these emission units are included in this analysis and are presented in the following sections. Since the 2017 actual emissions of SO_2 are very low (1.02 tons per year [tpy]), SO_2 emissions are not reviewed further in this analysis.

1.3.1 NORTH AND SOUTH BOILERS

The North and South Boilers are capable of firing wood or bark. The South Boiler is a C & E Dutch oven boiler with a rated steam capacity of 35,000 pounds per hour (lb/hr). The South Boiler was installed in 1944. Particulate emissions are controlled by a multiclone installed in 1994.

The North Boiler is an E.F. Huffman Dutch oven boiler with a rated steam capacity of 12,500 lb/hr. The North Boiler was installed in 1939. Particulate emissions are uncontrolled. The North Boiler is currently not operating.

The 2017 annual emissions from these boilers are presented in Table 1-3.

Table 1-3. 2017 Annual Emissions – Boilers

Emission Unit	NO_X Emissions (tons/yr)	PM_{10} Emissions (tons/yr)	SO_2 Emissions (tons/yr)
North Boiler (BLR-N)	0.0	0.0	0.0
South Boiler (BLR-S)	37.59	36.18	1.01

1.3.2 VENEER DRYERS (V-N)

The Facility operates two veneer dryers. The primary species of wood dried are White Fir, Pine, and Douglas Fir. Dryer particulate emissions are uncontrolled.

Dryer 1 (east dryer) was manufactured by Keller. It is a four deck, three zone jet tube dryer heated by burning natural gas. The maximum throughput is 13,000 ft^2/hr on a 3/8" basis. The maximum heating capacity of the burners associated with the dryer is 36 MMBtu/hr. The dryer was installed in 1984.

Dryer 2 (west dryer) was also manufactured by Keller. It is a four deck, three zone jet tube dryer heated by burning natural gas. The maximum throughput as-installed was 9,000 ft^2/hr on a 3/8" basis. The dryer was installed in 1989 and was modified in 2005 by adding another zone to increase the capacity to that of Dryer 1. The current capacity of Dryer 2 is 13,000 ft^2/hr on a 3/8" basis. The maximum heating capacity of the burners associated with the dryer is 41 MMBtu/hr.

The 2017 total annual emissions from both of the dryers are presented in Table 1-4.

Table 1-4. 2017 Annual Emissions – Veneer Dryers

Emission Unit	NO_X Emissions (tons/yr)	PM_{10} Emissions (tons/yr)	SO_2 Emissions (tons/yr)
Dryer #1 (east)	5.03	15.09	0.0
Dryer #2 (west)			

1.3.3 PLYWOOD PRESSES (PV-1, PV-2, PV-3)

There are three steam heated presses which exhaust directly to the atmosphere. The #1 North Press was installed in 1983. The maximum hourly production rate is 20,000 ft^2/hr on a 3/8" basis.

The #2 Middle Press was installed before 1978. The maximum hourly production rate was 16,250 ft^2/hr - 3/8" basis. This press was modified in 2002 by adding six platens for a total of 30. This change increased the capacity from 16,250 to 20,000 ft^2/hr on a 3/8" basis.

The #3 South Press was installed before 1978. The maximum hourly production rate is 16,250 ft^2/hr - 3/8" basis. This press was modified in 2015 by adding six platens for a total of 30. This change increased the capacity from 16,250 to 20,000 ft^2/hr on a 3/8" basis.

The 2017 total annual emissions from all three presses are presented in Table 1-5.

Table 1-5. 2017 Annual Emissions – Plywood Presses

Emission Unit	PM_{10} Emissions (tons/yr)
#1 North Press	2.29
#2 Middle Press	
#3 South Press	

1.4 FOUR FACTOR ANALYSIS METHODOLOGY

As discussed previously, the analysis requires the following steps to identify the technologically feasible control options for each emission unit applicable to the four factor analysis:

- The cost of compliance;
- Time necessary for compliance;
- Energy and non-air environmental impacts; and
- Remaining useful life of the source.

The following steps must be followed in conducting the analysis:

- Identify all available control technologies
- Eliminate technically infeasible options; and
- Rank the remaining options based on effectiveness.

1.4.1 FACTOR 1 – COST OF COMPLIANCE

The basis for comparison in the economic analysis of the control scenarios is the cost effectiveness; that is, the value obtained by dividing the total net annualized cost by the tons of pollutant removed per year for each control technology. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, and such maintenance costs as replacement parts, overhead, raw materials, and utilities. Capital costs include both the direct cost of the control equipment and all necessary auxiliaries as well as both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, start-up costs, and contingencies.

For each technically feasible control option, this analysis will summarize potential emission reductions, estimated capital cost, estimated annual cost, and cost-effectiveness (dollars per ton of pollutant). Per EPA guidance, SLR followed the methods in EPA's Air Pollution Control Cost Manual for this analysis.

1.4.2 FACTOR 2 – TIME NECESSARY FOR COMPLIANCE

Factor 2 involves the evaluation of the amount of time needed for full implementation of the different control strategies. The time for compliance will need to be defined and should include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis should also include the time required for staging the installation of multiple control devices at a given facility if applicable.

1.4.3 FACTOR 3 – ENERGY AND OTHER IMPACTS

Energy and environmental impacts include the following but are not limited to and/or need to be included in the analysis:

Energy Impacts
- Electricity requirement for control equipment and associated fans
- Water required
- Fuel required

Environmental Impacts
- Waste generated
- Wastewater generated
- Additional carbon dioxide (CO_2) produced
- Reduced acid deposition
- Reduced nitrogen deposition
- Impacts to Regional Haze

Non-air environmental impacts (positive or negative) can include changes in water usage and waste disposal of spent catalyst or reagents. EPA recommends that the costs associated with non-air impacts be included in the Cost of Compliance (Factor 1). Other effects, such as deposition or climate change due to greenhouse gases (GHGs) do not have to be considered.

For this analysis, SLR evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, any offsetting negative impacts on visibility from controls operation, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, increased water requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance (O&M) costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1 and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility.

1.4.4 FACTOR 4 – REMAINING EQUIPMENT LIFE

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a specific emission source is less than the lifetime of the pollution control device that is being considered. An appropriate useful life is selected and used to calculate emission reductions, amortized costs, and cost per ton of pollutant.

2. EMISSIONS CONTROL TECHNOLOGY ASSESSMENT

The emission control technology feasibility assessments were performed for the applicable units and pollutants in Table 2-1. Technical feasibility is demonstrated based on physical, chemical, or engineering principles.

Table 2-1. Applicable Unit

Emission Units	Pollutant(s)
South Boiler	PM_{10}, NO_X
North Boiler	PM_{10}, NO_X
Veneer Dryers	PM_{10}, NO_X
Plywood Press	PM_{10}

As outlined in the New Source Review (NSR) Workshop Manual (Draft), control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions or (2) the technology could be applied to the source under review.

2.1 SOUTH BOILER – WOOD/BARK FIRED

The South Boiler is a wood-fired dutch oven boiler with a maximum rated steam capacity of 35,000 lb/hr which is equivalent to approximately 49 MMBtu/hr of heat input. Actual NO_X emissions total 37.59 tons per year. The boiler was manufactured and installed in 1944, making it challenging to modify due to both its age and the dated dutch oven design. The boiler is considered an industrial boiler with a maximum heat input rate of less than 100 MMBtu/hr. As part of this analysis, the retrofit control technologies were identified by researching the U.S. EPA Reasonably Available Control Technology/Best Available Control Technology/Lowest Achievable Emission Rate (RACT/BACT/LAER) Clearinghouse (RBLC) database, engineering and permitting experiences, and surveying available literature.

2.1.1 NO_X CONTROL TECHNOLOGIES

In an industrial boiler, emissions of NO_X are formed in three ways: thermal, fuel bound, and prompt. Thermal NO_X is created by high flame temperature in the presence of oxygen. Fuel bound NO_X is inherent in fuel. Prompt NO_X is formed when nitrogen molecules in the air react with fuel during combustion. NO_x emission control technologies identified which may be available for use on the boiler are shown in Table 2-2.

Table 2-2. NO_X Control Technologies – South Boiler

Control Technology	Control Efficiency (%)	Technically Feasible
Good Combustion Practices	Base Case	Base Case – Feasible
Over Fire Air (OFA)	30-50	Infeasible
Low NO_X Burner (LNB)	30-60	Infeasible

Control Technology	Control Efficiency (%)	Technically Feasible
Flue Gas Recirculation	40-80	Infeasible
Selective Non-catalytic Reduction	25-50	Infeasible
Selective Catalytic Reduction	70-90	Infeasible

A description and evaluation of each of these control technologies is found in the following sections.

2.1.1.1 Good Combustion Practices

Good combustion practices can lower the emission of NO_X by using operational and design elements that optimize the amount and distribution of excess air in the combustion zone. Good combustion practices can be implemented by operating the boiler according to the manufacturer's recommendation, periodic inspections and maintenance, and periodic tuning of boilers to maintain excess air at optimum levels. Good combustion practices are currently used for the boiler and are considered technically feasible for this analysis.

2.1.1.2 Overfire Air

An overfire air (OFA) system is a combustion staging process that diverts a portion of the combustion air away from the primary combustion zone and creates an oxygen depleted zone that reduces the formation of NO_X. OFA systems have demonstrated NO_X reduction efficiencies of approximately 30% to 50%. Although OFA is commonly applied to wood-fired utility boilers, this system is not applied to dutch oven industrial boilers. OFA is also not listed as a control device for NO_X emissions from wood-fired boilers in the RBLC database. OFA retrofit is not considered technically feasible to install on the South Boiler due to the limited space between the top row of the burners and the convective pass. Therefore, OFA is removed from further consideration for the purpose for this analysis.

2.1.1.3 Low NO_X Burners

Low NO_X burners (LNBs) are a pre-combustion control technology that reduces combustion temperature and thus reduces the formation of thermal NO_X. The technology requires careful control of the fuel-air mixture during combustion. LNBs have demonstrated NO_X reduction efficiencies of approximately 30% to 60%. In order to apply an LNB in a wood fired boiler the technology generally requires pulverized fuel. The South Boiler is a dutch oven boiler which uses solid wood fuel in the burner. The solid fuel and the high moisture content in fuel would not create an appropriate environment needed for the effective operation of the LNB.

LNBs are also not listed as a control device for NO_X emissions from wood-fired boilers in the RBLC database. Therefore, LNBs are not considered a technically feasible control option for NO_X emissions from the combustion of solid wood fuel on the South Boiler.

2.1.1.4 Flue Gas Recirculation

Flue gas recirculation (FGR) requires recirculating a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NO_X formation. FGR has demonstrated NO_X reduction efficiencies of approximately 45%.

FGR technology in the boiler will require installing additional ductwork, combustion air fans, and additional structures to recirculate the flue gases from the boiler exhaust stack back into the combustion zone. Due to the extensive structural changes and addition of new equipment, FGR is difficult to retrofit on the existing boiler. The boiler is over 70 years old and the extensive structural changes required to install FGR are not feasible. The boiler also has extremely limited space for any new installation. Therefore, FGR is not considered technically feasible for the boiler.

2.1.1.5 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a post-combustion NO_X control technology in which a reagent (typically ammonia or urea) is injected into the exhaust gases to react chemically with NO_X, forming nitrogen and water. The success of this process in reducing NO_X emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Outside the upper end of the temperature range, the reagent will be converted to NO_X. Below the lower end of the temperature range, the reagent will not react with the NO_X and discharge from the stack (ammonia slip). SNCR systems are capable of sustained NO_X removal efficiency in the range of approximately 25% to 50%.

The exhaust temperature from the South Boiler is approximately 370°F based on the recent source test performed in 2018. However, as mentioned above, SNCR usually operates at gas temperatures ranging from 1,700°F to 2,000°F. In addition, there are also site-specific limitations (space requirement, age of the boilers) of installing all the necessary equipment required for this control technology. Therefore, SNCR is considered technically infeasible for the south boiler.

2.1.1.6 Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion technology that employs ammonia in the presence of a catalyst to convert NO_X to nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_X decomposition reaction. Therefore, the chemical reduction reaction between ammonia and NO_X occurs at much lower temperatures than those required for SNCR systems. The necessary temperature range for the SCR system depends on the type of catalysts. Most SCR systems operate in the range of 550°F to 750°F. However, high-temperature catalysts can operate above 750°F. Typical catalysts include vanadium pentoxide, titanium dioxide, noble metals, and tungsten trioxide.

Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system. When properly designed and operated, SCR systems can achieve NO_X removal efficiencies in the range of 70% to 90%.

The exhaust temperatures from the boiler is approximately 370°F which is below the operating range of 550°F to 750°F for SCR. Furthermore, the PM emissions from the south boiler would foul and poison the catalyst. The deactivation of the catalyst would eliminate the application for SCR to control NO_X emissions. Therefore, SCR is considered technically infeasible for the boiler.

2.1.2 PM_{10} CONTROL TECHNOLOGIES

Particulate matter (PM) emissions from wood-fired boiler consist of unburned carbon particles (soot), condensable vapors, and noncombustible materials (ash). PM_{10} emission control technologies identified which may be available for use on the boiler are shown in Table 2-3.

Table 2-3. PM_{10} Control Technologies – South Boiler

Control Technology	Control Efficiency (%)	Technically Feasible
Multiclone	Base Case	Base Case – Feasible
Venturi Scrubber	90%	Infeasible
Electrostatic Precipitator (ESP)	99%	Feasible
Fabric Filters (Baghouse)	99%	Infeasible

A description and evaluation of each of these control technologies is found in the following sections.

2.1.2.1 Multiclones

Multiclones are mechanical collectors which use centrifugal forces to separate particulate matter from an exhaust gas stream and recirculate back to the boiler. This technology works best when operating according to the maximum pressure drop identified in the design specification. The south boiler is already equipped with multiclones to control PM_{10} emissions.

2.1.2.2 Venturi Scrubber

A venturi scrubber removes PM from the gas stream by capturing the particles in liquid droplets and separating the droplets from the gas steam. The droplets act as conveyors of the particulate out of the gas stream.

A venturi scrubber consists of three sections: converging, throat, and diverging. The flue gas and the scrubbing liquid enter the converging and the throat sections, where the atomization of the scrubbing liquid takes place through the velocity of the flue gas. The atomized liquid provides an enormous number of tiny droplets for the dust particles to impact on. The gas liquid mixture decelerates in the diverging section and the liquid droplets incorporating the particulate matter are separated from the gas stream in a cyclonic separator with a mist eliminator. A venturi scrubber can be designed to achieve a PM removal efficiency of 90%.

Venturi Scrubbers are not listed as a control device for PM_{10} emissions from wood-fired boilers in the RBLC database. Therefore, a venturi scrubber is not considered technically feasible and is removed from further consideration for the purpose of this analysis.

2.1.2.3 Fabric Filters

Fabric filters, also referred to as baghouses, remove PM from a gas stream by passing the stream through porous fabrics. The efficiency of the fabric filter increases as the dust particles form a porous cake on the surface of the fabric. However, the dust particles need to be frequently removed from the fabric in order to maintain the optimum pressure drop across the system. Fabric filters can be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter.

According to U.S. EPA-CICA Fact Sheet, operating conditions are important determinants of the choice of fabric filter. Some fabrics (e.g., polyolefins, nylons, acrylics, polyesters) are useful only at relatively low temperatures of 200°F to 300°F. For high temperature flue gas streams, more thermally stable fabrics such as fiberglass, Teflon®, or Nomex® must be used. Temperatures in excess of 550°F require special refractory mineral or metallic fabrics, which can be expensive. Fabric filter systems can be designed to have a PM removal efficiency in excess of 99%.

A fabric filter has the potential to experience filter clogging (blinding) for boilers that combust high moisture content fuels. In addition, according to US EPA's AP-42, Section 1.6, fabric filters also have the potential to catch and/or cause fire that arises "from the collection of combustible carbonaceous fly ash." Therefore, due to the risk associated with this technology, the fabric filter is not considered technically feasible for the South Boiler. Please note that there are no entries found in the RBLC that show fabric filters for wood-fired industrial boilers less than 100 MMBtu/hr.

2.1.2.4 Electrostatic Precipitator

Electrostatic precipitators (ESPs) use electrical forces to remove particulates from a gas stream and move them onto collector plates. PM in the gas stream is given an electrical charge when it passes through a corona, a region with gaseous ion flow. Electrodes are maintained at high voltage and generate the electrical field that forces PM to the collector walls. After PM is collected, it is knocked off or "rapped" by various mechanical means to dislodge the particulate for collection in hoppers. ESPs can be designed for a wide range of gas temperatures, and can handle temperatures up to 1300°F. ESPs are also capable of operating under high pressure (to 1,030 kPa (150 psi)) or vacuum conditions.

ESPs can be designed to have a PM removal efficiency of approximately 99%. Although, there are site-specific limitations (space requirement, age of the boilers), an ESP is considered technically feasible for the purpose of this analysis.

2.2 NORTH BOILER

The North Boiler is also a wood-fired dutch oven boiler with a maximum rated steam capacity of 12,500 lb/hr which is equivalent to approximately 17 MMBtu/hr of heat input. The emissions control technologies reviewed for the South Boiler are also applicable to the North Boiler. However, the North Boiler is rarely operated and the permitted emissions are extremely low. Due to the low emissions from this boiler and the high cost of any feasible control options identified for the South Boiler, application of good combustion practices are the only technically feasible control option for the North Boiler.

Table 2-4. Control Technology – North Boiler

Control Technology	Control Efficiency (%)	Technically Feasible
Good Combustion Practices	Base Case	Base Case – Feasible

2.3 VENEER DRYERS

CFP operates two veneer dryers (Dryer 1 and Dryer 2) equipped with natural gas burners. Dryer 1 and Dryer 2 have a maximum throughput of 13,000 ft^2/hour and 9,000 ft^2/hour, respectively. PM_{10} emissions from veneer dryers are the result of fuel combustion and condensable PM associated with higher weight gaseous organic compounds. NO_X emissions are associated with the natural gas combustion. The emissions from the veneer dryers are currently minimized by implementing best management practices which include operating the dryers in accordance with manufacturers' recommendations.

2.3.1 PM_{10} CONTROL TECHNOLOGIES

Multiple cyclones, electrified filter beds, wet scrubbers, and wet ESPs can be used to control PM_{10} emissions from the dryers. However, these control technologies are not commonly used for veneer dryers. There is only one entry found in the RBLC database that lists multiclones as a control technology for PM emission from a veneer dryer. The veneer dryers each include a heating zone and a cooling zone and each zone is equipped with several exhaust stacks. Due to multiple stacks associated with the dryers, it would be difficult to install add-on controls, such as a multiclone to successfully control emissions of PM. Therefore, for the purpose of this analysis, multiclones are not considered technically feasible for the veneer dryers.

Table 2-5. PM_{10} Control Technologies – Veneer Dryers

Control Technology	Control Efficiency (%)	Technically Feasible
Best Management Practice	Base case	Base Case – Feasible
Multiclone	10-40	Infeasible

2.3.2 NO_X CONTROL TECHNOLOGIES

LNBs are the only control technology identified in the RBLC database for veneer dryers. As mentioned previously, LNBs have demonstrated NO_X reduction efficiencies of approximately 30% to 60%. For the purpose of this analysis, LNBs are considered a technically feasible control option for NO_X emissions from the natural gas burners associated with the veneer dryers.

Table 2-6. NO_X Control Technologies – Veneer Dryers

Control Technology	Control Efficiency (%)	Technically Feasible
Best Management Practice	Base case	Base Case – Feasible
LNB	30-60	Feasible

2.4 PLYWOOD PRESSES

CFP operates three steam heated presses each with a maximum production of 20,000 ft^2 per hour. PM_{10} emissions from these presses consist of very fine wood materials and condensable PM from organic compounds. As shown in Table 1-5 the total permitted PM_{10} emissions from the presses are only 2.5 tpy. Due to the extremely low emissions from these presses and the high cost of any add-on emission controls, additional PM_{10} controls would not be feasible. The emissions from the presses are currently minimized by implementing best management practices which include operating the presses in accordance with manufacturers' recommendations.

Table 2-7. Control Technology – Plywood Presses

Control Technology	Control Efficiency (%)	Feasibility
Best Management Practice	Base Case	Base Case – Feasible

3. FOUR FACTOR ANALYSIS

This section addresses the following four factors for the technologically feasible control options identified in Section 2 as requested by Oregon DEQ.

- Cost of compliance
- Time necessary for compliance
- Energy and non-air environmental impacts
- Remaining useful life of the source

For these four factors, this analysis followed EPA guidance[1] as well as EPA's Air Pollution Cost Manual.

3.1 FACTOR 1 – COST OF COMPLIANCE

The cost of compliance analysis estimated the capital cost, annual cost, and cost-effectiveness of each control option identified as technically feasible according to the methods and recommendations in the U.S. EPA's Air Pollution Control Cost Manual. The capital cost includes the equipment cost and the installation costs (direct and indirect). The annual cost includes O&M costs. The cost-effectiveness (dollar per ton of pollutant removed) is calculated using the total net annualized costs of control, divided by the actual tons of pollutant removed per year, for each control technology. The 2017 actual emissions for each applicable emission unit are used as baseline emissions for this analysis. The capital recovery factor applied in this analysis is 0.0786, based on a 20-year equipment life and 4.75% interest rate as noted in Oregon DEQ's *Fact Sheet – Regional Haze: Four Factor Analysis (December 5, 2019)*. The costs are adjusted to 2020 dollar values due to inflation. The detailed cost calculations are provided in Attachment A.

3.1.1 ESP – SOUTH BOILER

The capital and O&M costs for an ESP are based on the average cost data provided in U.S. EPA's *Air Pollution Control Technology – Fact Sheet (EPA 452/F-03-024)* and the design flowrate of the clay handling system. According to U.S. EPA document (EPA/452/B-02-001), the useful life of an ESP varies between 4 to 30 years and the typical useful life is about 20 years. Therefore, a useful life of 20 years was used for this analysis. Table 3-1 summarizes the costs of an ESP for the South Boiler. The cost effectiveness value of approximately \$11,400 per ton of PM_{10} removed is clearly excessive and indicates that the installation of an ESP is not cost effective for the South Boiler.

[1] *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019)*

Table 3-1. Cost Effectiveness – ESP for South Boiler

Parameter	Value
Design Flowrate (scfm)	9,762
Total Capital Cost Total O&M Cost Total Annualized Cost	$395,058 $385,794 $416,826
Control Efficiency (%)	99
PM_{10} Emissions Reduction (tons/yr)	36.43
Cost Effectiveness ($/ton PM_{10} removed)	**11,441**

3.1.2 LNB – VENEER DRYERS

The capital and O&M costs for the LNB are based on the average cost data provided in Table 14 of U.S. EPA's *Technical Bulletin – Nitrogen Oxides (NO_x), Why and How They Are Controlled (EPA 456/F-99-006R, November 1999)* and the maximum heat rates of the dryers. Table 3-2 summarizes the costs of LNBs for the dryers. The cost effectiveness value of approximately $70,000 per ton of NO_X removed is clearly excessive and indicates that the installation of LNBs is not cost effective for each dryer.

Table 3-2. Cost Effectiveness – LNB for Veneer Dryer

Parameter	Dryer 1	Dryer 2
Maximum Heat Rate (MMBtu/hr)	36	41
Total Capital Cost Total O&M Cost Total Annualized Cost	$291,600 $59,940 $82,845	$332,100 $68,265 $94,352
Control Efficiency (%)	45	45
NO_x Emissions Reduction (tons/yr)	1.13	1.13
Cost Effectiveness ($/ton NO_X removed)	**73,201**	**83,368**

3.2 FACTOR 2 – TIME NECESSARY FOR COMPLIANCE

This factor addresses the estimated time needed for the design and installation of the technically feasible control options. Per U.S. EPA's Technical document[2], the installation of LNBs may require up to 8 months. Due to the site specific constraints and age of the applicable units, installation of LNBs will be complex and may require additional time than provided by U.S. EPA guidance. A similar timeline is proposed for an ESP. The projected time for compliance is provided in Table 3-3. Although these control options have are already been deemed as not cost effective, the following information is provided per U.S. EPA guidance.

[2] *Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance (November 2015)*

Table 3-3. Time for Compliance

Control Options	Time Necessary for Compliance
LNB (for Veneer Dryer)	12 Months (approx.)
ESP (for South Boiler)	12 Months (approx.)

3.3 FACTOR 3 – ENERGY AND NON-AIR ENVIRONMENTAL IMPACTS

This subsection addresses the energy and non-air environmental impacts associated with the installation and operation of the technically feasible control options. These impacts are based on the information from standard resources (e.g., U.S. EPA Technical documents) and professional experience and judgement.

3.3.1 ESP – SOUTH BOILER

The installation of an ESP for the South Boiler would increase the annual electric consumption of the facility. Electricity is required for the operation of a fan, electric field generation, and cleaning. The power required for a fan is dependent on the pressure drop across the ESP, the flowrate, and the operating time. The annual electricity cost is included in the O&M costs of the cost analyses summarized in Table 3-1. The non-environmental impacts include landfilling of solid waste generated in the form of the collected dust from operation of the ESP.

3.3.2 LNB – VENEER DRYERS

The energy impacts from the application of LNBs are expected to be minimal. However, the lower flame temperature associated with an LNB will decrease the efficiency and the performance of the burners. Therefore, to maintain the same amount of heat required for the dryers, the burners will be required to burn more fuel.

LNBs are not expected to have any non-air environmental impacts.

3.4 FACTOR 4 – REMAINING USEFUL LIFE OF SOURCE

Per EPA guidance, the useful life of the control equipment will be less than the useful life of the facility itself. Although most of the applicable units are more than 50 years old, CFP has no plan of shutting down any of the equipment currently. Therefore, the remaining useful life of the sources is assumed to be 20 years, which is the typical useful life of the control equipment.

4. CONCLUSIONS

At the request of the Oregon DEQ, a four factor analysis was prepared for CFP. The analysis identified technically feasible control options for applicable emission units and evaluated the technology for the following four statutory factors:

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

Based on the above evaluation, SLR has determined that it is not technically feasible or cost effective to implement additional emission controls for the emission units at CFP.

5. REFERENCES

United States Environmental Protection Agency (USEPA). 2017. Office of Air Quality Planning and Standards Control Cost Manual. Office of Air Quality Planning and Standards, Economic Analysis Branch, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. November. (Chapter 2, updated November, 2017)

USEPA. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019)

USEPA. Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance (November 2015)

USEPA. Technical Bulletin – Nitrogen Oxides (NOx), Why and How They Are Controlled (EPA 456/F-99-006R, November 1999)

Oregon Department of Environmental Quality (DEQ). Fact Sheet – Regional Haze: Four Factor Analysis (December 5, 2019)

ATTACHMENT A

COST ANALYSIS

Table 1. ESP Retrofit Cost Effectiveness - South Boiler
Columbia Forest Products
Klamath Falls, Oregon

Parameter	Value	Reference
Design Flowrate (scfm)	9,762	2018 Source Test Data [(1)]
Capital Cost ($/scfm) in 2002 dollars	21.5	EPA-452/F-03-028 (Fact Sheet) - Average of Range [(2)]
O&M Cost ($/scfm) in 2002 dollars	21	EPA-452/F-03-028 (Fact Sheet) - Average of Range [(2)]
Capital Cost ($/scfm) in 2020 dollars	31.13	Adjusted for Inflation - CPI Inflation Calculator [(3)]
O&M Cost ($/scfm) in 2020 dollars	30.4	Adjusted for Inflation - CPI Inflation Calculator [(3)]
Total Capital Cost ($)	395,058	Design Rate (scfm) x 2020 Capital Cost ($/scfm) x Retrofit Factor (1.3) [(4)]
Total O&M Cost ($)	385,794	Design Rate (scfm) x 2020 O&M Cost ($/scfm) x Retrofit Factor (1.3) [(4)]
i, Interest Rate (%)	4.75	DEQ's Regional Haze; Four Factor Analysis - Fact Sheet (12/5/2019)
n, Equipment Life	20	EPA Cost Control Manual [(4)]
Capital Recovery Factor (CRF) =	0.08	i (1+ i)n/(1+ i)n - 1
Total Capital Investment (TCI) =	31,032	Total Capital Cost ($) x CRF
Total Annualized Cost ($) =	416,826	Total O&M Cost ($) + TCI ($)
Baseline PM_{10} Emissions (tons/yr)	36.80	2017 Annual Emissions
Control Efficiency (%)	99	Assumed
PM_{10} Reduction (tons/yr)	36.43	Baseline emissions x Control Efficiency/100
Cost Effectiveness ($/ton)	**11,441**	**Total Annual Cost/PM_{10} Removed/year**

Notes:
scfm = standard cubic feet per minute (flow rate)
O&M = Operations and Maintenance
1) Source Test Report - 2018 Compliance Testing - Columbia Forest Products - South Boiler (EU BLR-S), Klamath Falls, Oregon - Prepared by Montrose Air Quality Services, LLC (October 23, 2018)
2) U.S. EPA, Air Pollution Control Technology Fact Sheet, Dry Electrostatic Precipitator (ESP) - Wire-Plate Type (EPA-452/F-03-028)
3) CPI Inflation Calculator - Bureau of Labor Statistics - https://data.bls.gov/cgi-bin/cpicalc.pl
4) U.S. EPA, Cost Control Manual, Section 6, Chapter 3 - EPA/452/B-02-001, 2002. https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf

Table 2. Low NO_X Burner (LNB) Retrofit Cost Effectiveness - Veneer Dryers

Columbia Forest Products

Klamath Falls, Oregon

Parameter	Dryer 1	Dryer 2	Reference
Maximum Heat Input Rate (MMBtu/hr)	36	41	Design Specifications
Capital Cost ($/MMBtu) in 1993 dollars	4475	4475	Table 14. EPA-456/F-99-00R (November 1999) - Average of Range [(1)]
O&M Cost ($/MMbtu) in 1993 dollars	920	920	Table 14. EPA-456/F-99-00R (November 1999) - Average of Range [(1)]
Capital Cost ($/MMBtu) in 2020 dollars	8100	8100	Adjusted for Inflation - CPI Inflation Calculator [(2)]
O&M Cost ($/MMBtu) in 2020 dollars	1665	1665	Adjusted for Inflation - CPI Inflation Calculator [(2)]
Total Capital Cost ($)	291,600	332,100	Design Rate (MMBtu/hr) x 2020 Capital Cost ($/MMBtu)
Total O&M Cost ($)	59,940	68,265	Design Rate (MMBtu/hr) x 2020 O&M Cost ($/MMBtu)
i, Interest Rate (%)	4.75	4.75	DEQ's Regional Haze; Four Factor Analysis - Fact Sheet (12/5/2019)
n, Equipment Life	20	20	EPA Cost Control Manual [(3)]
Capital Recovery Factor (CRF) =	0.08	0.08	i (1+ i)n/(1+ i)n - 1
Total Capital Investment (TCI) =	22,905	26,087	Total Capital Cost ($) x CRF
Total Annualized Cost ($) =	82,845	94,352	Total O&M Cost ($) + TCI ($)
Baseline NO_X Emissions (tons/yr)	2.52	2.52	2017 Annual Emissions
Control Efficiency (%)	45	45	Chemical Engineering Progress (CEP), Magazine, January 1994 [(4)]
NO_X Reduction (tons/yr)	1.13	1.13	Baseline emissions x Control Efficiency/100
Cost Effectiveness ($/ton)	**73,201**	**83,368**	**Total Annual Cost/NO_X Removed/year**

Notes:

O&M = Operations and Maintenance

1) U.S. EPA, Technical Bulletin on Nitrous Oxides (Nox), Why and How They are Controlled, EPA-465/F-99-00R, 1999
   https://www3.epa.gov/ttncatc1/dir1/fnoxdoc.pdf
2) CPI Inflation Calculator - Bureau of Labor Statistics - https://data.bls.gov/cgi-bin/cpicalc.pl
3) U.S. EPA, Cost Control Manual, EPA/452/B-02-001, 2002. https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf
4) Chemical Engineering Progress (CEP) Magazine, January 1994; ClearSign Combustion Corporation, May 2013

ATTACHMENT B

SUPPORTING DOCUMENTS

Table 1. Emissions Details
Regional Haze Four Factor Analysis
Columbia Forest Products - Klamath Falls. Oregon

Emissions Source	2017 Throughput	Permitted Throughput	Throughput Unit	Pollutant(s)	Emission Factor	Emission Factor Unit	Reference	2017 Emissions (tons/yr)	Permitted Emissions (tons/yr)
South Boiler (BLR-S)	144,588,000	175,200,000	lbs steam/yr	PM_{10}	0.50	lb/1000 lb steam	94% of PM -1994 ST	36.18	43.84
				SO_2	0.01	lb/1000 lb steam	DEQ factor	1.01	1.23
				NO_X	0.52	lb/1000 lb steam	Avg. of all valid ST	37.59	45.55
Noth Boiler (BLR-N)	0	35,040,000	lbs steam/yr	PM_{10}	0.30	lb/1000 lb steam	86% of PM - 1994 ST	0.00	5.28
				SO_2	0.01	lb/1000 lb steam	DEQ factor	0.00	0.25
				NO_X	0.37	lb/1000 lb steam	Avg. of all valid ST	0.00	6.48
Veneer Dryers (V-N)	83,829	162,540	MSF/yr	PM_{10}	0.36	lb/MSF	Avg. of all valid ST	15.09	29.26
				NO_X	0.12	lb/MSF	DEQ factor	5.03	9.75
Plywood Press (PV)	114,402	162,790	MSF/yr	PM_{10}	0.04	lb/MSF	2000 ST	2.29	3.26
Storage Pile (SP)	114,402	162,790	MSF/yr	PM_{10}	0.03	lb/MSF	EPA Fire factor (emission factors based on plywood production)	1.72	2.44
Material handling (cyclones, target box, baghouses)	114,402	162,790	MSF/yr	PM10	0.033	lb/MSF	EPA Fire factor (emission factors based on plywood production)	1.92	2.73

Table 1. RBLC Search - Wood-Fired Industrial Boilers less than 100 MMBtu/hr - PM_{10}
Permit Date Between 01/01/2010 And 05/14/2020

RBLCID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Primary Fuel	Throughput	Throughput Unit	Control Method Description	Emission Limit	Emission Limit Unit	Case-by-Case Basis
*WI-0276	LOUISIANA-PACIFIC CORPORATION	WI	14-DCF-189	4/2/2015	B11 & B12 Boilers	Wood Waste	19.4	mmBTU/hr	Cyclone, Wet Electrostatic Precipitator, and Thermal Oxidizer in series	6.1	LB/HR	BACT-PSD
*WI-0276	LOUISIANA-PACIFIC CORPORATION	WI	14-DCF-189	4/2/2015	B21 & B22 Boilers	Wood Waste	23.8	mmBTU/hr	Cyclone, Wet Electrostatic Precipitator, and Thermal Oxidizer in series	6.1	LB/HR	BACT-PSD

Table 2. RBLC Search - Wood-Fired Industrial Boilers less than 100 MMBtu/hr - NO_X
Permit Date Between 01/01/2010 And 05/14/2020

RBLCID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Primary Fuel	Throughput	Throughput Unit	Control Method Description	Emission Limit	Emission Limit Unit	Case-by-Case Basis
*WI-0276	LOUISIANA-PACIFIC CORPORATION	WI	14-DCF-189	4/2/2015	B11 & B12 Boilers	Wood Waste	19.4	mmBTU/hr	Good Combustion Practices	8.9	LB/HR	BACT-PSD
*WI-0276	LOUISIANA-PACIFIC CORPORATION	WI	14-DCF-189	4/2/2015	B21 & B22 Boilers	Wood Waste	23.8	mmBTU/hr	Good Combustion Practices	16.2	LB/HR	BACT-PSD

Table 1. RBLC Search - Natural Gas-Fired Veneer Dryer - PM_{10}
Permit Date Between 1/1/2000 And 05/14/2020

RBLCID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Throughput	Throughput Unit	Control Method Description	Emission Limit	Emission Limit Unit	Case-by-Case Basis
MT-0021	PLUM CREEK MANFACTURING, EVERGREEN FACILITY	MT	2602-08	8/10/2002	PLYWOOD VENEER DRYERS				12.6	LB/H	BACT-PSD
TX-0292	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	TX	PSD-TX-924	8/6/2000	REJECT VENEER DRYER, EPN19A/B	25000	SQ FT/H	CYCLONE A & B	1.5	LB/H	Other Case-by-Case

Table 2. RBLC Search - Natural Gas-Fired Veneer Dryer - NO_X
Permit Date Between 1/1/2000 And 05/14/2020

RBLCID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Throughput	Throughput Unit	Control Method Description	Emission Limit	Emission Limit Unit	Case-by-Case Basis
LA-0259	FLORIEN PLYWOOD PLANT	LA	PSD-LA-755	1/31/2012	Veneer Dryer No. 1- 4 Heated Zones			Low NOx Burners	8.49	LB/H	BACT-PSD
LA-0125	WILLAMETTE INDUSTRIES, INC.	LA	PSD-LA-627 (M-1)	1/7/2002	VENNER DRYER NO.2 COOLING ZONE				0.88	LB/H	BACT-PSD
LA-0125	WILLAMETTE INDUSTRIES, INC.	LA	PSD-LA-627 (M-1)	1/7/2002	VENEER DRYERS, HOT ZONES			RTO/RCO	10.27	LB/H	BACT-PSD
LA-0125	WILLAMETTE INDUSTRIES, INC.	LA	PSD-LA-627 (M-1)	1/7/2002	VENNER DRYER NO.1 COOLING ZONE				0.37	LB/H	BACT-PSD

REGIONAL HAZE FOUR-FACTOR ANALYSIS

OCHOCO LUMBER COMPANY

Prepared for

OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY

OCHOCO LUMBER COMPANY
(DBA) MALHEUR LUMBER COMPANY
June 10, 2020
Project No. 1461.01.03

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CONTENTS

ACRONYMS AND ABBREVIATIONS

$/ton	dollars per ton of pollutant controlled
Analysis	Regional Haze Four Factor Analysis
CAA	Clean Air Act
Control Cost Manual	USEPA Air Pollution Control Cost Manual
DEQ	Oregon Department of Environmental Quality
ESP	electrostatic precipitator
°F	degrees Fahrenheit
facility	lumber and wood pellet/wood brick manufacturing facility located at 60339 West Highway 26, John Day, Oregon
Federal Guidance Document	USEPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
HAP	hazardous air pollutant
MACT	Maximum Achievable Control Technology
MMBtu/hr	Million British thermal units per hour
Malheur	Malheur Lumber Company
MFA	Maul Foster & Alongi, Inc.
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO	nitric oxide
NO_x	oxides of nitrogen
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
USEPA	U.S. Environmental Protection Agency

1 INTRODUCTION

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

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

(1) The cost of control,

(2) The time required to achieve control,

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

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

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

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

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

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

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

1.1 Facility Description

Ochoco Lumber Company owns and operates Malheur Lumber Company (Malheur), a lumber and wood pellet/wood brick manufacturing facility located at 60339 West Highway 26, John Day, Oregon (the facility). The nearest Class I area is the Strawberry Mountain Wilderness, approximately 8.5

kilometers southeast of the facility. The facility currently operates under Standard Air Contaminant Discharge Permit number 12-0032-ST-01 issued by the DEQ on June 25, 2019. The facility is a minor stationary source of criteria pollutants and hazardous air pollutants (HAPs).

1.2 Process Description

1.2.1 Lumber Manufacturing

Logs received by the Malheur facility are debarked and bucked (cut) to the appropriate length. The cut log segments (blocks) are sawn into various pieces of dimensional lumber based on the size and shape of the blocks. Generated sawdust will be transferred to a load-out bin for other use or sale. Wood scraps from the sawmill will be hogged and used as boiler feed.

After sawing, the dimensional lumber is still green (wet) so it is stacked for drying in one of the onsite kilns, which are steam-heated. Depending upon the moisture and species of wood, the green lumber is dried for 50 or more hours. When dried to the appropriate final moisture content, the lumber is planed to final dimensions. Planer shavings are bagged and sold for uses such as animal bedding. Wood species utilized by the facility include, but are not limited to, Ponderosa Pine, White Fir, Hemlock, Douglas Fir, and Larch.

1.2.2 Torrefied-Wood Production

Green log shavings and wood chips will be stored outside at the north end of the property. A loader will place these materials into a hopper to feed an indirectly heated belt dryer, which dries the material to approximately 10% moisture. The belt dryer will use heat from the torrefier, a high temperature rotary kiln, to generate a high volume of low temperature air which will be passed through the wood on the belt. The dried materials from the belt dryer will be screened, then conveyed to the torrefier. Torrefied material will be conveyed in an enclosed drag chain conveyor to the densification process, which will consist of pelleting and/or briquetting equipment. In the event that there is decreased demand for torrefied wood, the facility will have the ability to bypass the torrefier and use the dry material to manufacture wood pellets.

2 APPLICABLE EMISSION SOURCES

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

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

After emission rates were tabulated for each emissions unit, estimated emission rates for each pollutant were sorted from the highest emission rate to the lowest. The emission units collectively contributing to 90 percent of the total facility emissions rate for a single pollutant were identified and selected for the Analysis.

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

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

2.1 Sources of PM_{10} Emissions

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

2.1.1 Torrefier (TORR)

The direct-fired rotary kiln torrefaction unit (torrefier) is equipped with a low NO_X burner. Wood dried in the belt dryer is conveyed to the torrefier, where hemicellulose in the wood fibers undergoes thermal decomposition, producing low-heat synthesis gas (syngas). The propane burner used to heat the torrefier has a maximum rated heat input capacity of 44.1 million British thermal units per hour (MMBtu/hr).

The torrefier system incorporates syngas recirculation and combustion staging with tangential gas entry. This minimizes the amount of supplemental propane gas needed to maintain the torrefaction reaction. Process exhaust from the torrefier is routed to a thermal oxidizer for control of volatile organic compounds and organic HAP emissions.

2.1.2 Boiler 3 (BLR3)

Boiler 3 is a Hurst wood-fired boiler equipped with a low NO_X burner. It has a maximum rated heat input capacity of 58 MMBtu/hr. Boiler 3 was installed in 2019 but will not be through shakedown until late June of 2020. Steam produced from Boiler 3 is used to indirectly-heat the dry kilns for lumber production and the belt dryer. Process exhaust exiting Boiler 3 is routed to a downstream dry electrostatic precipitator (ESP) for control of fine particulate matter emissions.

Boiler 3 is subject to the National Emission Standards for Hazardous Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers Area Sources (Boiler MACT), codified at Title 40 Code of Federal Regulations 63, Subpart JJJJJJ, effective September 14, 2016. Based on the Federal Guidance Document, the USEPA believes it is reasonable for states to exclude a source for further analysis if

> For the purpose of particulate matter [PM] control measures, a unit that is subject to and complying with any CAA section 112 National Emission Standard for Hazardous Air Pollutants (NESHAP) or CAA section 129 solid waste combustion rule, promulgated or reviewed since July 31, 2013, that uses total or filterable PM as a surrogate for metals or has specific emission limits for metals. The NESHAPs are reviewed every 8 years and their emission limits for PM and metals reflects at least the maximum achievable control technology for major sources and the generally available control technology for area sources. It is unlikely that an analysis of control measures for a source meeting one of these NESHAPs would conclude that even more stringent control of PM is necessary to make reasonable progress.

Based on the Federal Guidance Document, and that Boiler 3 is already equipped with best-in-class control for fine particulate emissions, Boiler 3 was excluded from further evaluation in the Analysis.

2.1.3 Boilers 1 and 2 (BLR1 and BLR2)

Two Erie City water tube stoker wood-fired boilers (Boiler 1 and 2) are typically operated in a standby state as backup to Boiler 3. Each boiler has a maximum rated heat input capacity of 22.4 MMBtu/hr. The boilers supply steam to heat the dry kilns and the belt dryer. Process exhaust from each boiler is routed to multiclones for control of particulate emissions.

Each boiler is assumed to operate one at a time on an annual basis, for up to six months, at 50 percent load. However, on occasions of extreme weather, either Boiler 1 or 2 may operate at full load for short periods in addition to Boiler 3. In addition, at times where Boiler 3 is down for maintenance or repairs, both Boiler 1 and 2 may operate at full load.

Similar to Boiler 3, Boilers 1 and 2 are subject to the National Emission Standards for Hazardous Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers Area Sources (Boiler MACT), codified at Title 40 Code of Federal Regulations 63, Subpart JJJJJJ, effective September 14, 2016.

Boilers 1 and 2 have potential annual PM_{10} emissions of only 2.94 tons/yr combined. The boilers are separate emission points and each would require separate controls. MFA is unaware of any additional particulate controls that could be cost effectively applied. Given that they are permitted for limited use and they are primarily used as back-up to Boiler 3, Boilers 1 and 2 were excluded from further evaluation in the Analysis.

2.1.4 Unpaved Roads

The unpaved roads emissions unit is representative of fugitive emissions generated by vehicle traffic on unpaved roads. The facility conducts periodic sweeping and watering to on-site roads as preventative dust-control measures. Further control of the unpaved roads emissions unit is considered to be technically infeasible since capture and collection of emissions cannot reasonably be achieved. Therefore, the unpaved roads emissions unit was excluded from further evaluation in the Analysis.

2.2 Sources of NO_X Emissions

A summary of the selected emission units and associated NO_X emission rates to be evaluated in the Analysis is presented in the attached Table 2-2 (attached). As shown in the table, only Boiler 3 and the torrefier are included as a source for further evaluation in the Analysis. See Sections 2.1.1 and 2.1.2 for descriptions of the torrefier and Boiler 3 emissions units and associated existing control devices.

2.3 Sources of SO_2 Emissions

A summary of the selected emission units and associated SO_2 emission rates to be evaluated in the Analysis is presented in the attached Table 2-3 (attached). As shown in the table, only Boiler 3 is included as a source for further evaluation in the Analysis. See Section 2.1.2 for a description of the Boiler 3 emissions unit and associated existing control device.

2.4 Emission Unit Exhaust Parameters

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

3 REGIONAL HAZE FOUR FACTOR ANALYSIS METHODOLOGY

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

3.1 Step 1: Determine Emission Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

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

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

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

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

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

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

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

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

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

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

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

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

4 PM_{10} ANALYSIS

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

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

4.1.1 Baghouses

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

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

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

Biomass dust from the torrefaction process is highly flammable at low temperatures. The exhaust temperature for the torrefier system is estimated to be 435 °F to 450 °F, well above temperatures that would pose a risk of fire or explosion in a baghouse. Based on the high risk of fire and explosion hazards, baghouse control is considered to be technically infeasible for control of PM_{10} emissions from the torrefier.

4.1.2 Wet Venturi Scrubbers

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

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

4.1.3 Electrostatic Precipitator

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

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

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern as they reduce air pollution. Use of wet ESPs generates a wastewater and wet sludge effluent that requires treatment and subsequent disposal, thereby increasing the overall costs.

Biomass dust from the torrefaction process is highly flammable at low temperatures. The exhaust temperature for the torrefier system is estimated to be 435 °F to 450 °F, well above temperatures that would pose a risk of fire or explosion in a dry ESP. Based on the high risk of fire and explosion hazards, dry ESP control is considered to be technically infeasible for control of PM_{10} emissions from the torrefier.

The cost analyses for dry ESP installations are used as a surrogate for wet ESP. Wet ESP installations are expected to be higher due to the additional costs for wastewater treatment and disposal.

4.2 Step 2—Selection of Emissions

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

4.3 Step 3—Characterizing Cost of Compliance

Tables 4-2 and 4-3 (attached) present the detailed cost analyses of the technically feasible PM_{10} control technologies included in the Analysis. A summary of the cost of compliance, expressed in $/ton, is shown below:

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

Emissions Unit	Emissions Unit ID	Cost of Compliance ($/ton)	
		Venturi Scrubber	ESP
Torrefier	TORR	22,951	27,344

4.4 Step 4—Characterizing Time Necessary for Compliance

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

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

4.5.1 Energy Impacts

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

4.5.2 Environmental Impacts

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

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

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

4.6 Step 6—Characterize the Remaining Useful Life

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

5 NO_X ANALYSIS

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

5.1 Step 1—Determine NO_X Control Measures for Consideration

5.1.1 Selective Non-catalytic Reduction

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

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

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

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

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

5.1.2 Selective Catalytic Reduction and Hybrid Systems

Unlike SNCR, selective catalytic reduction (SCR) reduces NO_X emissions with ammonia in the presence of a catalyst. The major advantages of SCR technology are the higher control efficiency (70 to 90 percent) and the lower temperatures at which the reaction can take place (400°F to 800°F, depending on the catalyst selected). SCR is widely used for combustion processes, such as those using natural gas turbines, where the type of fuel produces a relatively clean combustion gas. In an

SNCR/SCR hybrid system, ammonia or urea is injected into the combustion chamber to provide the initial reaction with NO_X emissions, followed by a catalytic (SCR) section that further enhances the reduction of NO_X emissions. The primary reactions that take place in the presence of the catalyst are:

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

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

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

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

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

5.2 Step 2—Selection of Emissions

See Section 2 for a description of the NO_X emissions used in the Analysis.

5.3 Step 3—Characterizing Cost of Compliance

Table 5-2 (attached) presents the detailed cost analyses of the technically feasible NO_X control technologies included in the Analysis. A summary of the cost of compliance, expressed in \$/ton, is shown below in Table 5-1.

Table 5-1
Cost of Compliance Summary for NO_X

Emissions Unit	Emissions Unit ID	Control Technology	Cost of Compliance ($/ton)
Boiler 3	BLR3	SNCR	10,140
Torrefier	TORR	SNCR	30,076

5.4 Step 4—Characterizing Time Necessary for Compliance

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

5.5 Step 5—Characterizing Energy and non-Air Environmental Impacts

5.5.1 Energy Impacts

Direct energy impacts will result from the use of SNCR control systems. Energy use (e.g. electricity use) is limited to the operation of pumps for urea injection into the SNCR and the heating of the urea storage tank. As a result, direct energy impacts are expected to be minimal. SNCR systems utilize urea or ammonia reagents, which result in the consumption of fossil fuels, primarily natural gas, during the production process. Additionally, combustion devices controlled by SNCR using urea require additional fuel consumption to offset the increased moisture loads caused by the urea injection in the flue gas.

5.5.2 Environmental Impacts

SNCR units require the use of urea (or aqueous ammonia) injection in the exhaust stream. Any unreacted excess ammonia in the exhaust stream (i.e., ammonia slip) will be released to the atmosphere. Ammonia slip to the atmosphere is a contributor to fine particle formation, which further exacerbates the regional haze issue; ammonia is also considered to be a toxic air contaminant with associated human health risks, and is regulated under the Cleaner Air Oregon Program. Therefore, there is a trade-off between maximizing NO_X emission reductions and minimizing the potential for ammonia slip. Additionally, increased fuel use by the combustion device or in the manufacture of reagents will lead to additional greenhouse gas contributions as well as other regulated pollutants.

5.6 Step 6—Characterize the Remaining Useful Life

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

6 SO_2 ANALYSIS

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

6.1 Step 1—Determine SO_2 Control Measures for Consideration

6.1.1 Dry Sorbent Injection

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

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

Dry sorbent injection systems introduce PM emissions into the exhaust stream, as mentioned above. This will cause increases to the particulate inlet loading of downstream particulate-control devices. For retrofit applications, it is likely that modification of the downstream existing particulate-control device will be necessary in order to accommodate the increased particulate inlet loading. It is anticipated that this increased loading may not be accommodated solely through modifications to the existing control device. Additional particulate controls may be required, resulting in cost increases and further energy and environmental impacts.

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

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

6.2 Step 2—Selection of Emissions

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

6.3 Step 3—Characterizing the Cost of Compliance

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

6.4 Step 4—Characterizing Time Necessary for Compliance

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

6.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

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

6.6 Step 6—Characterize the Remaining Useful Life

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

7 CONCLUSION

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

LIMITATIONS

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

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

TABLES

Table 2-1
PM_{10} Evaluation for Regional Haze Four Factor Analysis
Malheur Lumber Company—John Day, Oregon

Emission Units (1)	Emission Unit ID(s)	Current PM_{10} Control Technology (1)	Pollution Control Device ID	Annual PM_{10} Emissions (2) (tons/yr)	Control Evaluation Included?	Rationale for Exclusion from Control Evaluation	Emission Controls to Be Evaluated
Torrefier	TORR	--	--	13.1	Yes	--	Baghouse, Venturi Scrubber, Electrostatic Precipitator
Boiler 3	BLR3	Dry ESP	ESP	9.98	No	Source is directly regulated for filterable PM as a surrogate for metals under Area Source Boiler MACT (40 CFR 63 Subpart JJJJJJ), which became effective September 14, 2016. Therefore, this source meets USEPA guidance for no further analysis.	--
Boilers 1 & 2	BLR1, BLR2	Multiclone	MC	2.94	Yes	Source is directly regulated for filterable PM as a surrogate for metals under Area Source Boiler MACT (40 CFR 63 Subpart JJJJJJ), which became effective September 14, 2016. Therefore, this source meets USEPA guidance for no further analysis.	--
Unpaved Roads	FUG	Road Watering/ Sweeping	--	2.55	No	Fugitive source. No further control is technically feasible.	--
All Other Emission Units	Varies	Varies per Emissions Unit	--	1.98 (3)	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

Color Key
MFA-specific ID.

NOTES:
CFR = Code of Federal Regulations.
ESP = electrostatic precipitator.
PM_{10} = particulate matter with an aerodynamic diameter of 10 microns or less.
MACT = maximum achievable control technology.

REFERENCES:
(1) Information taken from the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.
(2) Information taken from the Review Report for the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.
(3) Each emission unit in the lower 10th percentile of the total facility emissions rates has potential PM_{10} emissions of 1.08 tons per year or less.

Table 2-2
NO_X Evaluation for Regional Haze Four Factor Analysis
Malheur Lumber Company—John Day, Oregon

Emission Units (1)	Emission Unit ID(s)	Current NO_X Control Technology (1)	Annual NO_X Emissions (2) (tons/yr)	Control Evaluation Included?	Rationale for Exclusion from Control Evaluation	Emission Controls to Be Evaluated
Boiler 3	BLR3	Low-NO_x Burner	55.9	Yes	--	SCR, SNCR
Torrefier	TORR	Low-NO_x Burner	14.4	Yes	--	SCR, SNCR
Boiler 1 & 2	--	--	6.08	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:

NO_x = oxides of nitrogen.

SNCR = selective catalytic reduction.

SNCR = selective non-catalytic reduction.

REFERENCES:

(1) Information taken from the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.

(2) Information taken from the Review Report for the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.

Table 2-3
SO_2 Evaluation for Regional Haze Four Factor Analysis
Malheur Lumber Company—John Day, Oregon

Emission Units [(1)]	Emission Unit ID(s)	Current SO_2 Control Technology [(1)]	Annual SO_2 Emissions [(2)] (tons/yr)	Control Evaluation Included?	Rationale for Exclusion from Control Evaluation	Emission Controls to be Evaluated
Boiler 3	BLR3	--	6.35	Yes	--	Dry Sorbent Injection
All Other Emission Units	Varies	--	0.34	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:

SO_2 = sulfur dioxide.

REFERENCES:

(1) Information taken from the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.

(2) Information taken from the Review Report for the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.

Table 2-4
Emissions Unit Input Assumptions and Exhaust Parameters
Malheur Lumber Company—John Day, Oregon

Emissions Unit ID	Emissions Unit Description	Heat Input Capacity [(1)] (MMBtu/hr)	Exhaust Parameters			
			Exit Temperature (°F)		Exit Flowrate	
					(acfm) [(1)]	(scfm) [(a)]
BLR1	Line 1 Boiler	22.4	475	(1)	15,200	7,716
BLR2	Line 2 Boiler	22.4	475	(1)	15,200	7,716
BLR3	Boiler 3	58.0	400	(1)	30,000	16,556
TORR	Torrefier	44.1	435	(2)	19,480	10,331

NOTES:

°F = degree Fahrenheit.

acfm = actual cubic feet per minute.

ft/sec = feet per second.

MMBtu/hr = million British thermal units per hour.

NO_x = oxides of nitrogen.

PM_{10} = particulate matter with an aerodynamic diameter of 10 microns or less.

scfm = standard cubic feet per minute.

SO_2 = sulfur dioxide.

(a) Exit flowrate (scfm) = (exit flowrate [acfm]) x (1 - [6.73E-06] x [facility elevation above sea level {ft}])$^{5.258}$
x (530) / (460 + [exit temperature {°F}])

Facility elevation above sea level (ft) = 3,087 (3)

REFERENCES:

(1) Data provided by Malheur Lumber Company.

(2) Information taken from the Review Report for the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued by the Oregon DEQ on June 25, 2019.

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

Table 3-1
Operating and Maintenance Rates
Malheur Lumber Company—John Day, Oregon

Parameter	Value	(units)	
FACILITY OPERATIONS			
Annual Hours of Operation	8,760	(hrs/yr)	(1)
Annual Days of Operation	365	(day/yr)	(1)
Daily Hours of Operation	24.0	(hrs/day)	(1)
UTILITY COSTS			
Electricity Rate	0.061	($/kWh)	(2)
Natural Gas Rate	2.49	($/MMBtu)	(1)
Water Rate	14.5	($/Mgal)	(2)
Compressed Air Rate	0.003	($/Mscf)	(2)
Water Disposal Rate	24.0	($/Mgal)	(2)
Landfill Disposal Fee	44.9	($/ton)	(2)
LABOR COSTS			
Maintenance Labor Rate	27.00	($/hr)	(2)
Operating Labor Rate	22.00	($/hr)	(2)
Supervisory Labor Rate	30.00	($/hr)	(2)
Operating Labor Hours per Shift	2.00	(hrs/shift)	(3)
Maintenance Labor Hours per Shift	1.00	(hrs/shift)	(3)
Typical Shifts per Day	3.00	(shifts/day)	(2)

NOTES:

Mgal = thousand gallons.

kW-hr = kilowatt-hour.

scf = standard cubic feet.

REFERENCES:

(1) Assumes continuous annual operation.

(2) Data provided by Malheur Lumber Company.

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

Table 4-2
Cost Effectiveness Derivation for Wet Venturi Scrubber Installation
Malheur Lumber Company—John Day, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters			Pollutant Removed by Control Device [a] (tons/yr)	Operating Parameter		
		Exhaust Flowrate [1]		PM_{10} Annual Emissions Estimate [2] (tons/yr)		Pump and Fan Power Requirement [b] (kW)	Inlet Grain Loading [c] (gr/ft^3)	Annual Water Demand [c] (gal/yr)
		(acfm)	(scfm)					
TORR	Torrefier	19,480	10,331	13.1	13.0	62	0.018	664,506

Emissions Unit ID	Emissions Unit Description	Direct Costs			Total Indirect Costs [h]	Total Capital Investment [i]	Capital Recovery Cost of Control Device [j]	Direct Annual Costs								Total Indirect Annual Costs [q]	Total Annual Cost [r]	Annual Cost Effectiveness [s]
		Purchased Equipment Cost		Total Direct Cost [g]				Operating Labor		Maintenance		Utilities			Total Direct Annual Costs [15]			
		Basic Equip./Services Cost [e]	Total [f]					Operator Cost [l]	Supervisor Cost [m]	Labor Cost [l]	Material Cost [15]	Electricity Cost [n]	Water Usage Cost [o]	Wastewater Treatment Cost [p]				
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
TORR	Torrefier	$186,407	$219,960	$343,138	$76,986	**$420,124**	$39,795	$48,180	$7,227	$29,565	$29,565	$32,921	$9,635	$15,948	$173,041	$125,322	**$298,363**	**$22,951**

Table 4-2
Cost Effectiveness Derivation for Wet Venturi Scrubber Installation
Malheur Lumber Company—John Day, Oregon

NOTES:

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

Control efficiency (%) =	99.0	(3)

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

Typical water usage rate (gpm/1,000 acfm) =	4.27	(4)

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

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

(d) Water demand (gal/yr) = (control efficiency [%] / 100) x (inlet grain loading [gr/ft³]) x (lb/7,000 gr) x (exhaust flowrate [scfm]) x (60 min/hr) x (annual hours of operation [hrs/yr]) / (mass fraction of solids in recirculation water) / (density of water [lb/gal]); see reference (6).

Control efficiency (%) =	99.0	(3)
Annual hours of operation (hrs/yr) =	8,760	(5)
Mass fraction of solids in recirculation water =	0.25	(5)
Density of water (lb/gal) =	8.3	(5)

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

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

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

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

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

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

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

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

Control device capital recovery factor =	0.0947	(k)

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

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

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

Operator labor rate ($/hr) =	22.00	(5)
Operating labor hours per shift [hrs/shift) =	2.00	(5)
Maintenance labor rate ($/hr) =	27.00	(5)
Maintenance labor hours per shift [hrs/shift) =	1.00	(5)
Shifts per day (shifts/day) =	3.00	(5)
Annual days of operation (days/yr) =	365	(5)

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

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

Electricity rate ($/kWh) =	0.061	(5)

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

Water rate ($/Mgal) =	14.5	(5)

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

Sewage treatment rate ($/Mgal) =	24.0	(5)

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

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

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

Table 4-2
Cost Effectiveness Derivation for Wet Venturi Scrubber Installation
Malheur Lumber Company—John Day, Oregon

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-017) for venturi scrubber issued July 15, 2003. Assumes the maximum PM control efficiency and average capital cost.
(4) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.3.
(5) See Table 3-1, Operating and Maintenance Rates.
(6) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See section 2.5.5.1, and equations 2.36 and 2.37.
(7) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices.
(8) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.8.
(9) Conservatively assumes no costs associated with site preparation or building requirements.
(10) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See equation 2.42.
(11) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(12) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(13) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.5% as a default.
(14) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See section 2.6.2.2.
(15) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.9.

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Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Malheur Lumber Company—John Day, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters			Pollutant Removed by Control Device [a] (tons/yr)	Operating Parameter		
		Exhaust Flowrate [1]		PM_{10} Annual Emissions Estimate [2] (tons/yr)		System Pressure Drop [4] (inch w.c.)	Total Collection Plate Area Estimate [b] (ft^2)	ESP Inlet Grain Loading [c] (gr/ft^3)
		(acfm)	(scfm)					
TORR	Torrefier	19,480	10,331	13.1	13.0	6.0	4,132	0.018

Emissions Unit ID	Emissions Unit Description	Direct Costs			Total Indirect Costs [f]	Total Capital Investment [g]	Capital Recovery Cost of Control Device [h]	Direct Annual Costs										Total Indirect Annual Costs [s]	Total Annual Cost [t]	Annual Cost Effectiveness [u]
		Purchased Equipment Cost		Total Direct Cost [e]				Operating Labor			Maintenance		Utilities				Total Direct Annual Costs [13]			
		Basic Equip./Services Cost [5]	Total [d]					Operator Cost [j]	Supervisor Cost [k]	Coordinator Cost [l]	Labor Cost [m]	Material Cost [n]	Fan Electricity Cost [o]	Oper. Electricity Cost [p]	Compressed Air Cost [q]	Landfill Cost [r]				
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D	--	--	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
TORR	Torrefier	$604,474	$713,280	$1,191,177	$263,914	**$1,455,091**	$114,298	$48,180	$7,227	$16,060	$6,416	$7,133	$11,228	$4,255	$30,716	$749	$131,964	$223,511	**$355,474**	**$27,344**

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Malheur Lumber Company—John Day, Oregon

NOTES:

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

Control efficiency (%) =	99.0	(3)

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

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

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

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

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

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

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

(f) Total indirect cost ($) = (0.37) x (total purchased equipment cost [$]); see reference (8).

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

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

Control device capital recovery factor =	0.0786	(i)

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

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

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

Operator labor rate ($/hr) =	22.00	(6)
Operating labor hours per shift [hrs/shift) =	2.00	(6)
Shifts per day (shifts/day) =	3	(6)
Annual days of operation (days/yr) =	365	(6)

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

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

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

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

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

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

Annual hours of operation (hrs/yr) =	8,760	(6)
Electricity rate ($/kWh) =	0.061	(6)

(p) Annual operating power electricity cost ($) = (1.94E-03) x (total collection plate area estimate [ft^3]) x (annual hours of operation [hrs/yr]) x (electricity rate [$/kWh])

Annual hours of operation (hrs/yr) =	8,760	(6)
Electricity rate ($/kWh) =	0.061	(6)

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

Compressed air cost ($/Mscf) =	0.003	(6)
Annual hours of operation (hrs/yr) =	8,760	(6)

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

Annual hours of operation (hrs/yr) =	8,760	(6)
Landfilling cost ($/ton) =	57.00	(6)

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

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

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

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Malheur Lumber Company—John Day, Oregon

REFERENCES:

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

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

(3) USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-028) for dry electrostatic precipitator, wire-plate type issued July 15, 2003. Assumes the typical collection area and minimum new equipment design control efficiency.

(4) PPC Industries Quotation no. 18048/18049 (Revision 0) dated September 12 and 13, 2018. MFA obtained two separate costs and equipment requirements for dry ESPs sized at 21,000 acfm and 51,000 acfm. For the smallest exhaust flowrate above (MC4), the quoted data was scaled using a ratio. All other costs/data were scaled and obtained using tread line formulas. It is important to note that the quoted costs do not include the costs associated with taxes, freight, mechanical construction, electrical work, excavation, building/foundation upgrades, and permitting or licensing.

(5) excavation, building/foundation upgrades, and permitting or licensing.

(6) See Table 3-1, Operating and Maintenance Rates.

(7) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.16 "Capital Cost Factors for ESPs."

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

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

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

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

(12) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.4.2.

(13) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.21.

(14) See Chemical Engineering magazine, chemical engineering plant cost index section for annual indices.

Table 5-2
Cost Effectiveness Derivation for SNCR Installation
Malheur Lumber Company—John Day, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters				Pollutant Removed by Control Device		Normalized Stoichiometric Ratio (e)	Operating Parameters				
		Heat Input Capacity (1) (MMBtu/hr)	Uncontrolled NO_X Emissions Estimate		Uncontrolled NO_X Emissions in Flue Gas (b) (lb/MMBtu)	Hourly (c) (lb/hr)	Annual (d) (tons/yr)		Reagent Mass Consumption (f) (lb/hr)	Reagent Solution Flowrate (g) (gal/hr)	Power Demand (h) (kW)	Water Demand (i) (gal/hr)	Additional Fuel Usage (j) (MMBtu/hr)
			Hourly (a) (lb/hr)	Annual (3) (tons/yr)									
		Q_B	--	--	NO_{Xin}	--	--	NSR	$m_{reagent}$	q_{sol}	P	q_{water}	ΔFuel
BLR3	Boiler 3	58.0	12.8	55.9	0.22	3.19	14.0	1.30	10.8	2.27	35.8	10.3	0.087
TORR	Torrefier	44.1	3.29	14.4	0.075	0.82	3.60	2.85	6.11	1.29	35.4	5.86	0.049

Emissions Unit ID	Emissions Unit Description	Direct Cost	Indirect Cost	Total Capital Investment (m)	Capital Recovery Cost of Control Device (n)	Direct Annual Costs							Total Indirect Annual Costs (w)	Total Annual Cost (x)	Annual Cost Effectiveness (y)
						Maintenance Labor and Material Cost (p)	Reagent Usage (q)	Utilities				Total Direct Annual Costs (27)			
		Capital Cost (k)	Balance of Plant Cost (l)					Electricity Cost (s)	Water Usage Cost (t)	Fuel Additive Cost (u)	Ash Disposal Cost (v)				
USEPA COST MANUAL VARIABLE		$SNCR_{COST}$	BOP_{COST}	TCI	CR	--	--	--	--	--	--	DAC	IDAC	TAC	($/ton)
BLR3	Boiler 3	$153,247	$437,150	**$892,391**	$70,098	$13,386	$37,049	$18,988	$1,313	$312	$34	$71,082	$70,499	**$141,582**	**$10,140**
TORR	Torrefier	$116,601	$339,465	**$717,761**	$56,380	$10,766	$20,994	$18,809	$744	$177	$19	$51,510	$56,703	**$108,214**	**$30,076**

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Table 5-2
Cost Effectiveness Derivation for SNCR Installation
Malheur Lumber Company—John Day, Oregon

NOTES:

(a) Uncontrolled hourly NO_X emissions estimate (lb/hr) = (uncontrolled annual NO_X emissions estimate [tons/yr]) x (2,000 lb/ton) / (annual hours of operation [hrs/yr])

Annual hours of operation (hrs/yr) =	8,760	(2)

(b) Uncontrolled NO_X emissions in flue gas (lb/MMBtu) = (uncontrolled hourly NO_X emissions estimate [lb/hr]) / (heat input capacity [MMBtu/hr])

(c) Hourly pollutant removed by control device (lb/hr) = (uncontrolled hourly NO_X emissions estimate [lb/hr]) x (control efficiency [%] / 100)

Control efficiency (%) =	25.0	(4)

(d) Annual pollutant removed by control device (tons/yr) = (uncontrolled annual NO_X emissions estimate [tons/yr]) x (control efficiency [%] / 100)

Control efficiency (%) =	25.0	(4)

(e) Normalized stoichiometric ratio = ([2] x [uncontrolled NOX emissions in flue gas {lb/MMBtu}] + [0.7]) x (control efficiency [%] / 100) / (uncontrolled NOX emissions in flue gas [lb/MMBtu]); see reference (5).

Control efficiency (%) =	25.0	(4)

(f) Reagent mass consumption (lb/hr) = (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (heat input capacity [MMBtu/hr]) x (normalized stoichiometric ratio) x (60.06 lb-urea/lb-mole) / (46.01 lb-NO_2/lb-mole) / [theoretical stoichiometric ratio]); see reference (6).

Theoretical stoichiometric ratio =	2	(7)

(g) Reagent solution flowrate (gal/hr) = (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (aqueous reagent solution density [lb/ft³]) x (7.4805 gal/ft³); see reference (8).

Aqueous reagent solution concentration (%) =	50.0	(8)
Aqueous reagent solution density (lb/ft³) =	71.0	(8)

(h) Power demand (kW) = (0.47) x (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (normalized stoichiometric ratio) x (heat input capacity [MMBtu/hr]) / (net plant heat rate [MMBtu/MWh]); see reference (9). + (power required to heat tank [kW]); see reference (11).

Net plant heat rate (MMBtu/MWh) =	10.0	(10)
Power required to heat tank (kW) =	35.0	(11)

(i) Water demand (gal/hr) = (4) x (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (density of water [lb/gal]); see reference (12).

Aqueous reagent solution concentration (%) =	50.0	(8)
Density of water (lb/gal) =	8.345	

(j) Additional fuel usage (MMBtu/hr) = (9) x (heat of vaporization of water [Btu/lb]) x (reagent mass consumption [lb/hr]) x (MMBtu/1,000,000 Btu); see reference (22).

Heat of vaporization of water (Btu/lb) =	900	(13)

(k) Capital cost ($) = (capital cost [1999 $/MMBtu/hr]) x (heat input capacity [MMBtu/hr]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 1999)

Capital cost ($/MMBtu/hr) =	1,700	(4)
Chemical engineering plant cost index for 2019 =	607.5	(14)
Chemical engineering plant cost index for 1999 =	390.6	(14)

(l) Balance of plant costs ($) = (213,000) x ([heat input capacity {MMBtu/hr}] / [net plant heat rate {MMBtu/MWh}])^(0.33) x (hourly pollutant removed by control device [lb/hr])^(0.12) x (retrofit factor); see reference (13).

Net plant heat rate (MMBtu/MWh) =	10.0	(10)
Retrofit factor =	1.00	(15)

(m) Total capital investment ($) = (1.3) x ([capital cost {$}] + [balance of plant cost {$}]) + (reagent storage tank cost [$]) + (reagent storage tank construction [$]); see reference (24).

Reagent storage tank ($) =	74,875	(17)
Reagent storage area construction ($) =	50,000	(18)

(n) Control device capital recovery cost ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (25).

Control device capital recovery factor =	0.0786	(o)

(o) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (17).

Interest rate (%) =	4.75	(21)
SNCR economic life (yr) =	20	(22)

(p) Annual maintenance cost ($) = (0.015) x (total capital investment [$]); see reference (23).

(q) Annual reagent usage cost ($) = (reagent solution flowrate [gal/hr]) x (reagent cost [$/50% urea solution]) x (annual hours of operation [hrs/yr])

Table 5-2
Cost Effectiveness Derivation for SNCR Installation
Malheur Lumber Company—John Day, Oregon

Reagent rate ($/50% urea solution) =	1.86	(r)
Annual hours of operation (hrs/yr) =	8,760	(2)

(r) Reagent rate ($/50% urea solution) = (reagent cost [2016 $/50% urea solution]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 2016)

Reagent rate (2016 $/50% urea solution) =	1.66	(4)
Chemical engineering plant cost index for 2019 =	607.5	(14)
Chemical engineering plant cost index for 2016 =	541.7	(14)

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

Electricity rate ($/kWh) =	0.061	(2)
Annual hours of operation (hrs/yr) =	8,760	(2)

(t) Annual water usage cost ($) = (water demand [gal/hr]) x (Mgal/1,000 gal) x (water rate [$/Mgal]) x (annual hours of operation [hrs/yr])

Water rate ($/Mgal) =	14.5	(2)
Annual hours of operation (hrs/yr) =	8,760	(2)

(u) Annual fuel additive cost ($) = (high heating value estimate [Btu/lb) x (reagent mass consumption [lb/hr]) x (9) x (MMBtu/1,000,000 Btu) x (fuel rate [$/MMBtu]) x (annual hours of operation [hrs/yr]); see reference (23).

High heat value of wood (MMBtu/BDT) =	17.48	(25)
Wood fuel rate ($/BDT) =	21.00	(2)
Annual hours of operation (hrs/yr) =	8,760	(2)

(v) Ash disposal ($) = (additional fuel usage [MMBtu/hr]) x (ash production [wt%])/100 x (annual hours of operation [hrs/yr]) / (high heat value of wood [MMBtu/BDT]) x (landfill disposal rate [$/ton]); see reference (25).

Ash production (wt%) =	1.75	(27)
Annual hours of operation (hrs/yr) =	8,760	(2)
High heat value of wood (MMBtu/BDT) =	17.48	(25)
Landfill disposal rate ($/ton) =	44.90	(2)

(w) Total indirect annual cost ($) = (0.03) x (annual maintenance cost [$]) + (capital recovery cost [$]); see reference (29).
(x) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])
(y) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 3-1, Operating and Maintenance Rates.
(3) See Table 2-2, NO_X Evaluation for Regional Haze Four Factor Analysis.
(4) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR) issued July 15, 2003. Assumes the average PM control efficiency and average capital cost.
(5) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.17.
(6) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.18.
(7) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. Assumes theoretical stoichiometric ratio for urea.
(8) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.19 and 1.20.
(9) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.42.
(10) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.3.1.
(11) Information provided by Chromalox vendor. Assumes heating of urea is required to a minimum of 95°F.
(12) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.45.
(13) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.48.
(14) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices.
(15) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.37. Assumes retrofit factor.
(16) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.35.

Table 5-2
Cost Effectiveness Derivation for SNCR Installation
Malheur Lumber Company—John Day, Oregon

(17) Cost for storage tank and heating unit. Includes shipping and installation costs.
(18) Cost for construction of covered tank storage area and secondary containment.
(19) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(20) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(21) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(22) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.4.2.
(23) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.39.
(24) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.49.
(25) 40 CFR, Subchapter C, Part 98, Subpart C. See Table C-1 "Default CO2 Emission Factors and High Heat Values of Various Types of Fuel". Factor for wood and wood residuals.
(26) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.50 and 1.51.
(27) Average wood ash production from burning of hogged fuel.
(28) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.38.
(29) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.52 and 1.53.

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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

Prepared on behalf of:
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Brookings Facility
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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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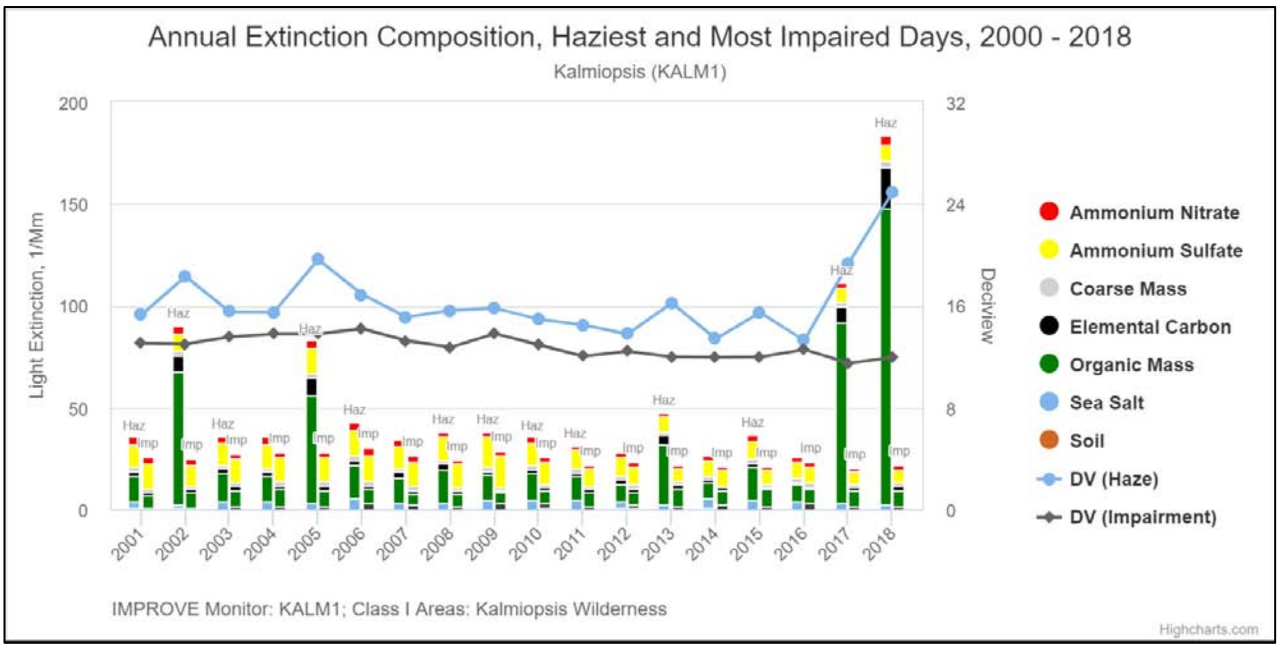
[3] A mandatory Class I area is usually a national park or wilderness area above a certain threshold size (4,000 or 5,000 acres) and in existence on or before August 7, 1977.

[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.

[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.

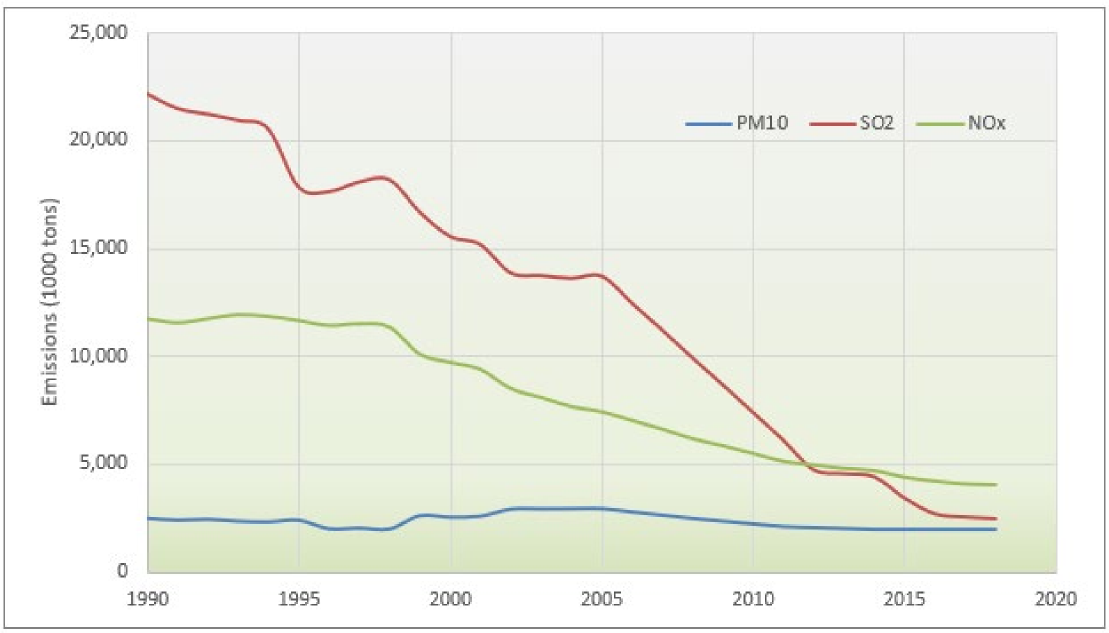
3.0 REASONABLE PROGRESS PERSPECTIVE

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

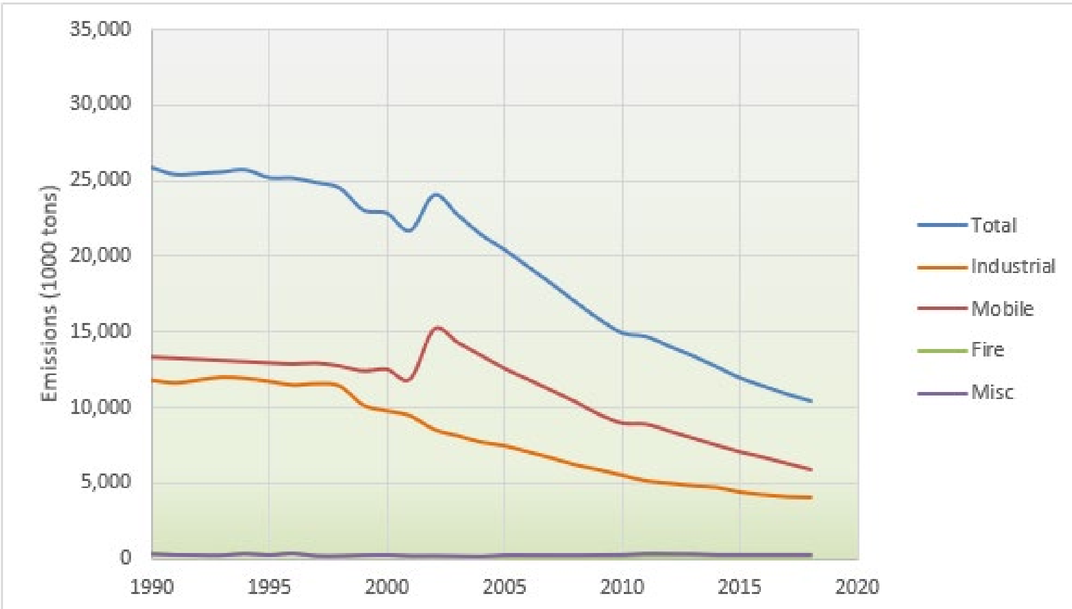
Category	NEI Source Groups
Industrial	Fuel Combustion: Electric Utility, Industrial, & Other Chemical and Allied Product Manufacturing Metals Processing Petroleum and Related Industries Other Industrial Processes Solvent Utilization Storage and Transport Waste Disposal and Recycling
Mobile/Transportation	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

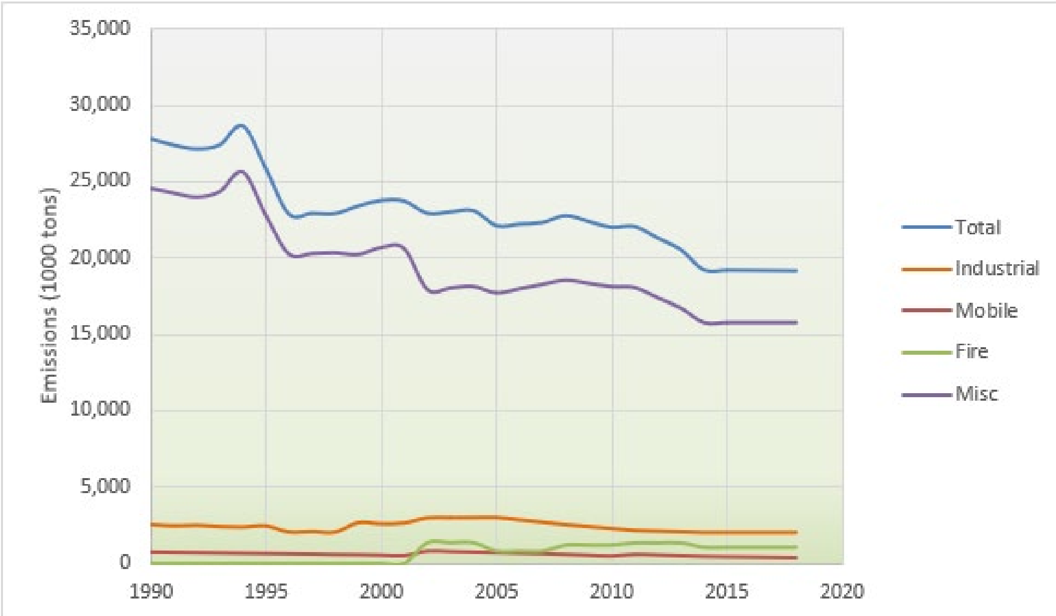
contributor of NO_x emissions originates from on-road vehicles and nonroad engines and vehicles. On-road vehicles include light-duty and heavy-duty gas and diesel vehicles. Nonroad engines and vehicles account for non-road gasoline and diesel engines, aircraft, marine vessels, railroads, and other sources.

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)

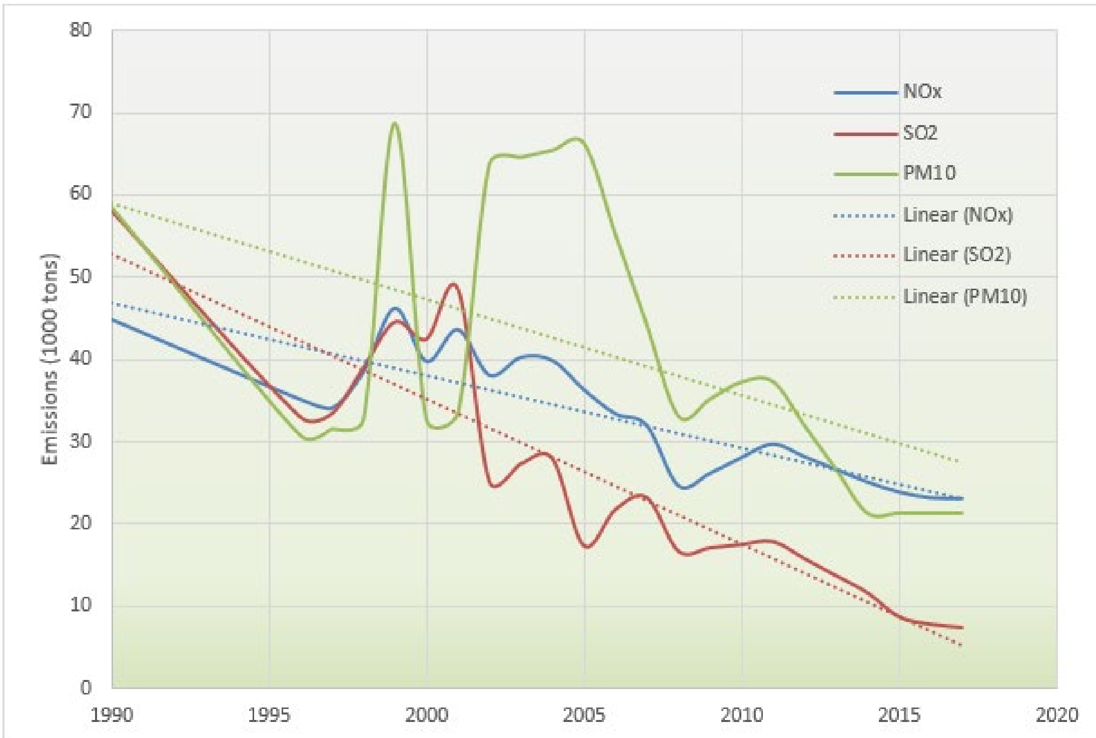


Figure 3-5: Oregon Total Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)

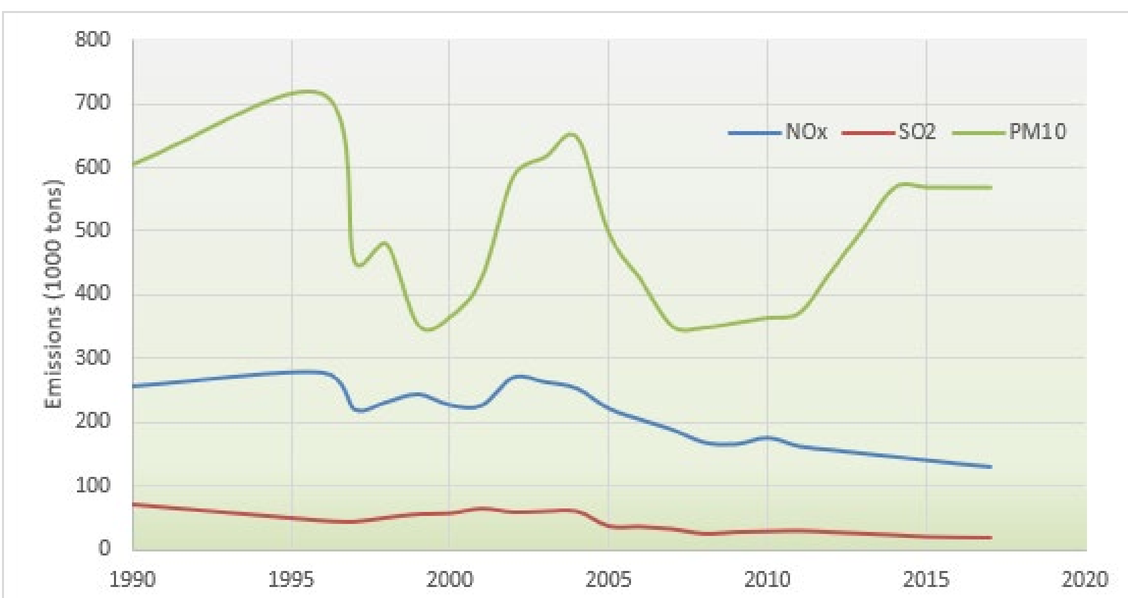
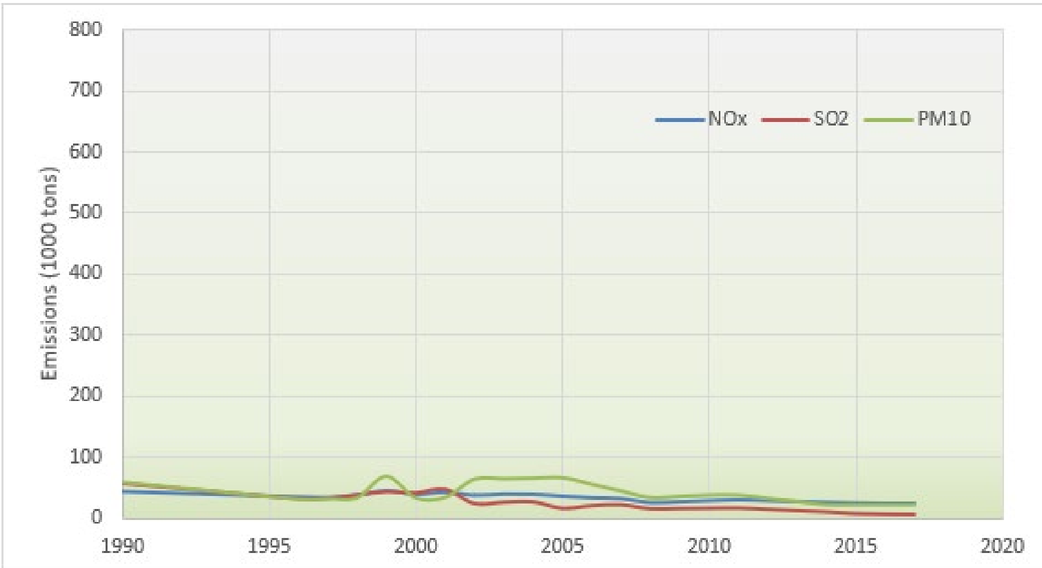


Figure 3-6 provides the industrial emissions data included in Figure 3-4 but in context to the scale of the y-axis in Figure 3-5. This demonstrates the contribution of industrial emissions to total state emissions.

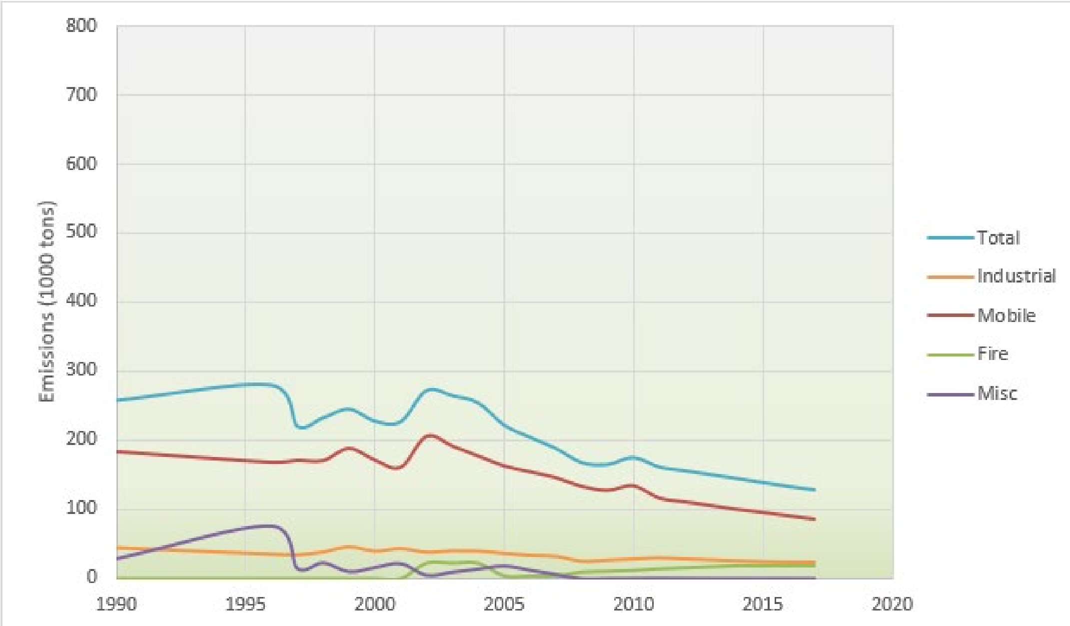
Figure 3-6: Oregon Industrial Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)



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



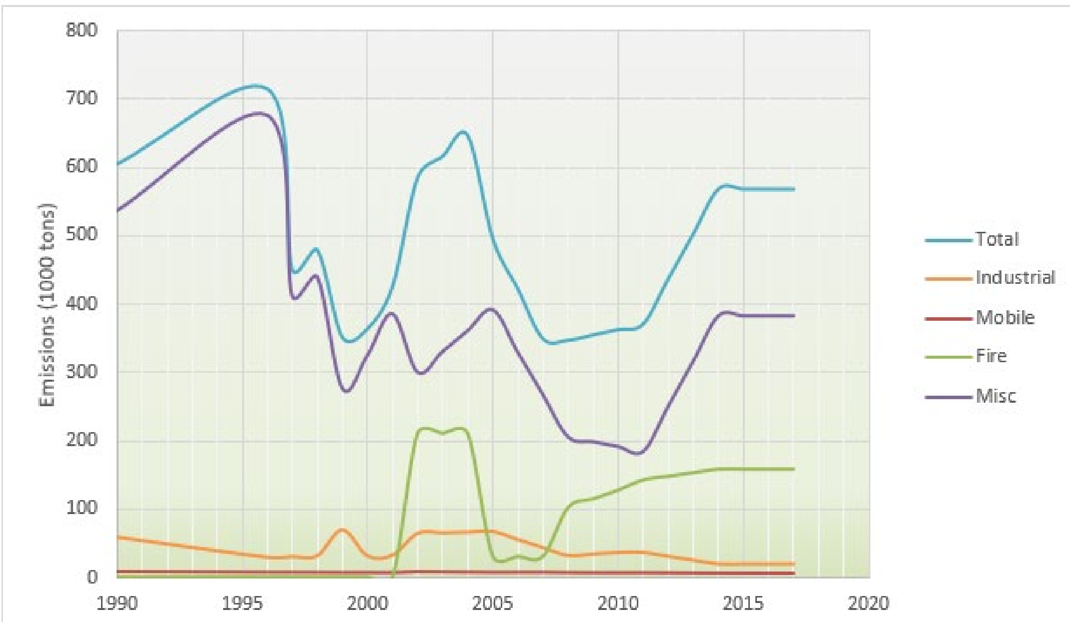
Similarly, Figure 3-8 compares the contribution of PM_{10} emissions across source groups to the state-wide total. Industrial sources again contribute minimally to total emissions (4% in 2017), whereas the "Miscellaneous" source group accounts for 48% to 95% of total PM_{10} emissions from 1990 – 2018 (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]

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[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.

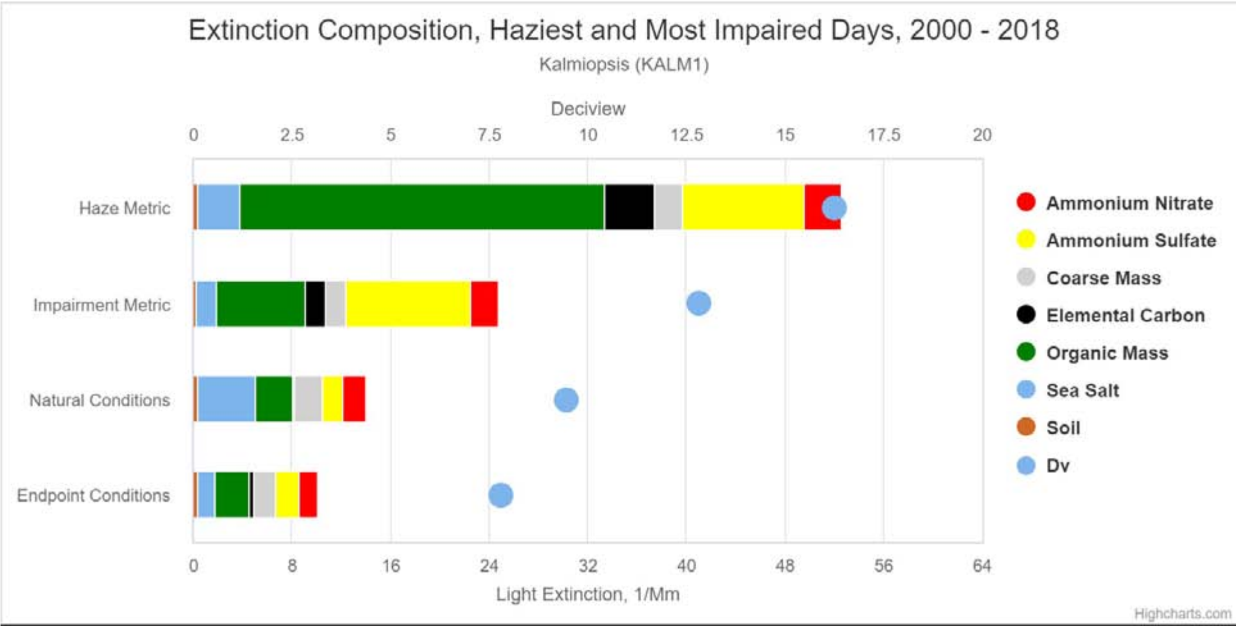
3.4 Emissions vs Visibility Impairment Analysis

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.

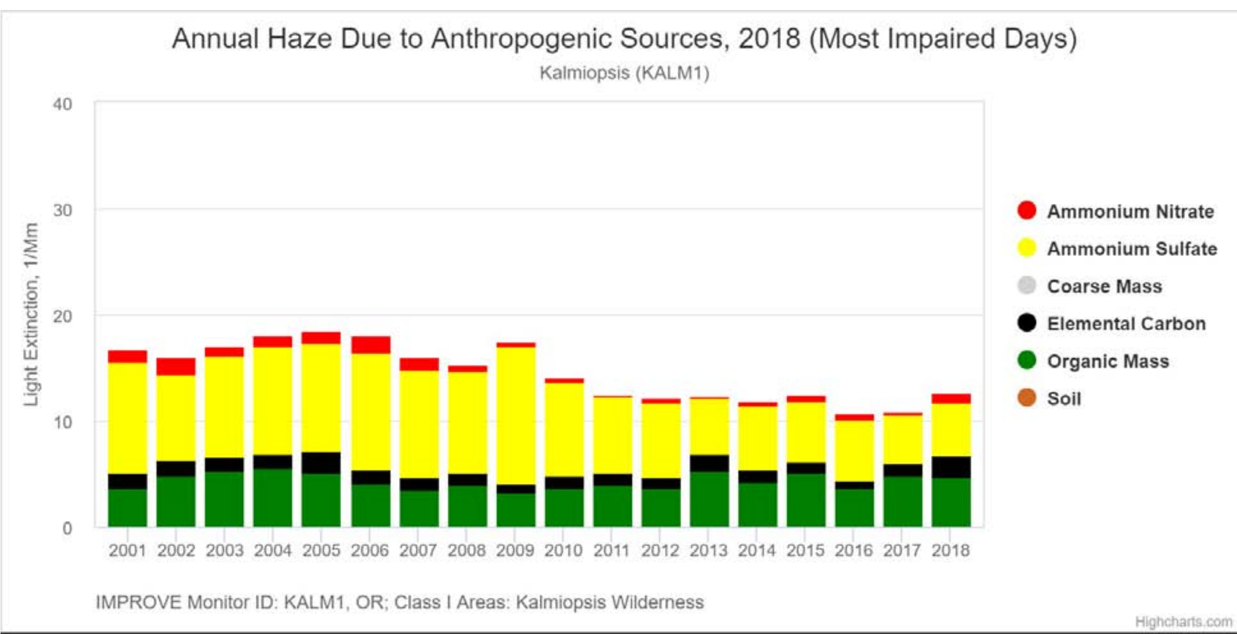
Figure 3-9 indicates a similar representation of haze and impairment contributions by providing the extinction composition by deciview for each metric [6]. Clearly, organic mass dominates the haze metric while ammonium sulfate provides the majority of the impairment metric. As stated previously, visibility 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.

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[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

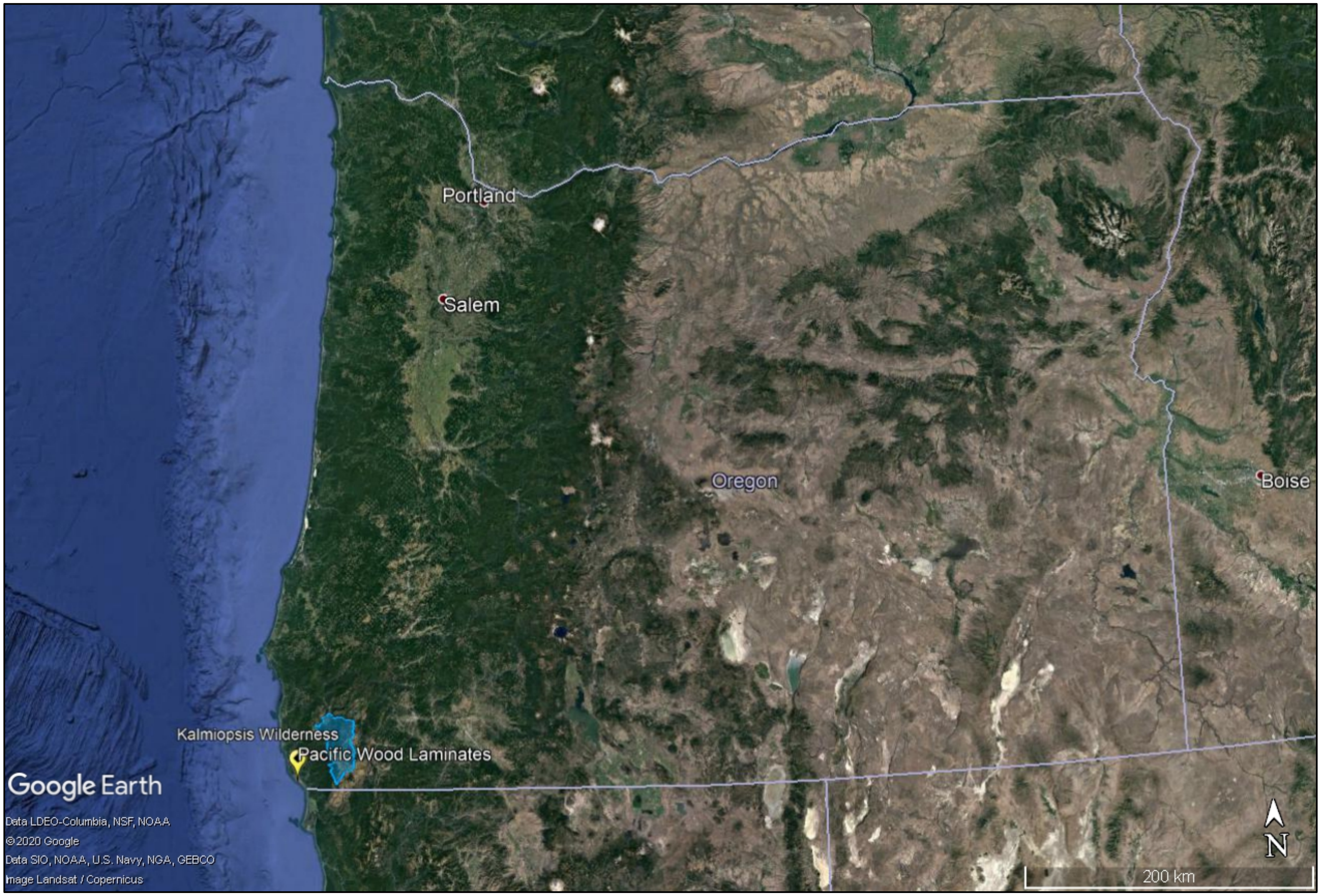
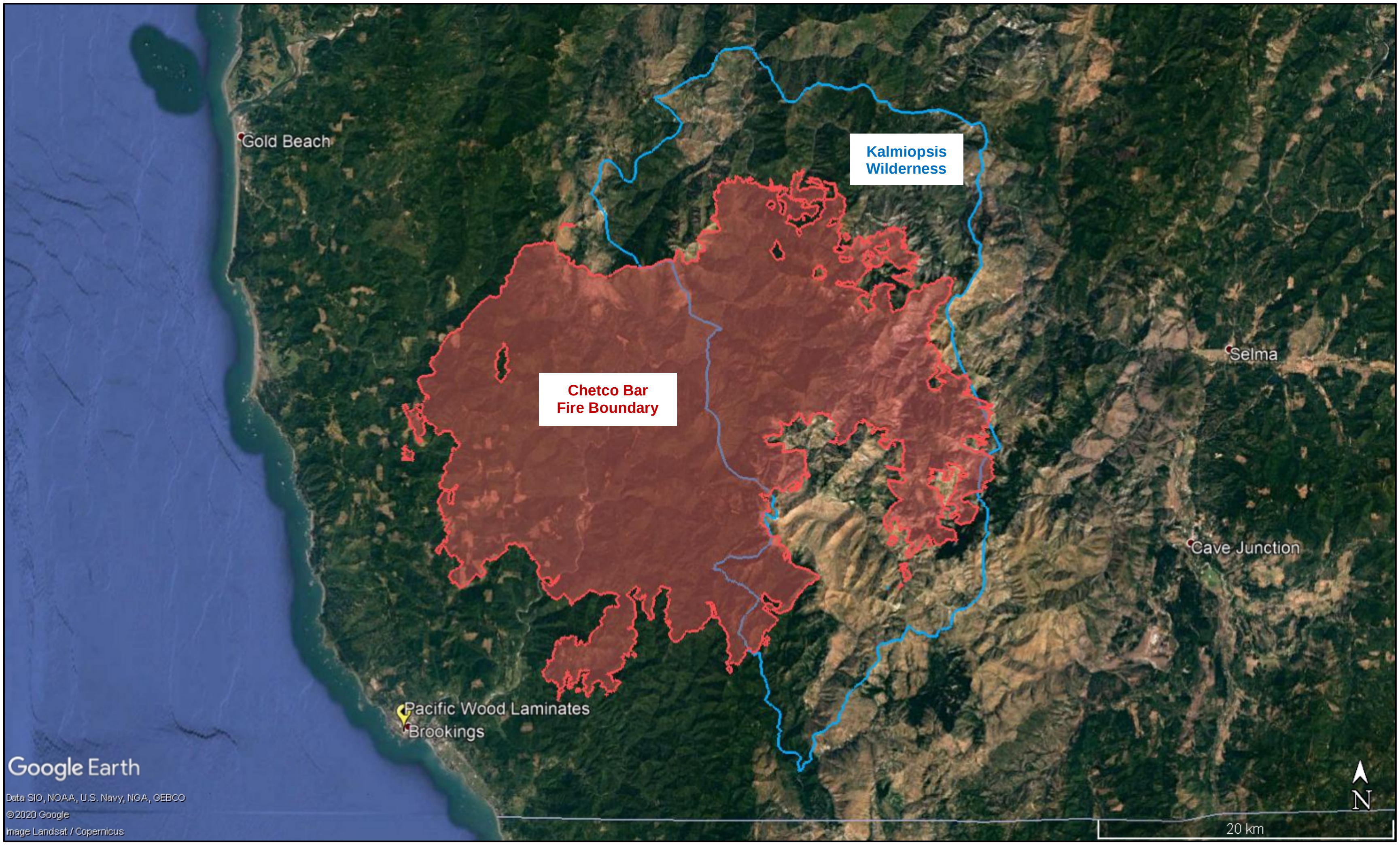


Figure 4-3: PWL Proximity to Kalmiopsis Wilderness Area with Chetco Bar Fire Impact Area



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 - 500ºF.

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.

[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.

Current PM_{10} Emissions

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 lb/klb * 295,671 klb/yr ÷ 2000 lb/ton = 29.3 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

STATE OF OREGON 1859

Oregon

Kate Brown, Governor

Department of Environmental Quality
Agency Headquarters
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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]

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[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.

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[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

Step 1: 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.

Step 2: 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.

Step 3: 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.

Step 4: 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.

Step 5: 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} x 7.4805 x $t_{storage}$ x 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) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.22	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1 \times 10^6)/HHV$ =	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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 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.			

<u>Total Annual Costs, TAC</u>						
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.						
<u>Direct Annual Costs Summary</u>						
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.

Ken Kinsley
Wellons, Inc.
360-750-3505

Swanson Group
Accountability
Commitment
Excellence
Safety

Swanson Group Manufacturing
PO Box 250
Glendale, OR 97442
Office (541) 832-1121
Fax (541) 832-1139
www.swansongroup.biz

June 1, 2020

DEPT OF ENVIRONMENTAL QUALITY
RECEIVED
JUN 03 2020
NORTHWEST REGION

Department of Environmental Quality
Agency Headquarters
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Subject: Regional Haze Four Factor Analysis; Swanson Group Mfg.LLC

Per your request Swanson Group has completed the analysis for our plywood production facility in Glendale Oregon.

DEQ Facility ID:	10-0045
Federal Facility ID:	8004811
Facility name:	Swanson Group Mfg. LLC
Facility Address:	303 MEHLWOOD LANE Glendale, OR 97442

Sincerely

Jeff Remington

Jeff Remington
VP of Engineering
Office 541-832-1194
Cell 541-761-0533
E-fax 541-832-1433

REGIONAL HAZE FOUR FACTOR ANALYSIS

SWANSON GROUP MANUFACTURING

Prepared for
SWANSON GROUP MFG. LLC
GLENDALE, OREGON
May 29, 2020
Project No. 0472.04.01

MAUL
FOSTER
ALONGI

Prepared by
Maul Foster & Alongi, Inc.
6 Centerpointe Drive, Suite 360, Lake Oswego, OR 97035

CONTENTS

ACRONYMS AND ABBREVIATIONS

$/ton	dollars per ton of pollutant controlled
°F	degrees Fahrenheit
Analysis	Regional Haze Four Factor Analysis
CAA	Clean Air Act
CFR	Code of Federal Regulations
Control Cost Manual	USEPA Air Pollution Control Cost Manual
DEQ	Oregon Department of Environmental Quality
ESP	electrostatic precipitator
existing permit	Title V Operating Permit no. 10-0045-TV-01
facility	veneer and plywood manufacturing facility located at 303 Mehlwood Lane, Glendale, Oregon 97442
Federal Guidance Document	Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
GACT	Generally Available Control Technology
HAP	hazardous air pollutant
hogged fuel boiler	Babcock and Wilcox Dutch-oven-type hogged fuel boiler
MFA	Maul Foster & Alongi, Inc.
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO	nitric oxide
NO_X	oxides of nitrogen
PCWP	Plywood and Composite Wood Products
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
Swanson	Swanson Group Mfg. LLC
USEPA	U.S. Environmental Protection Agency
VOC	volatile organic compound

1 INTRODUCTION

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

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

(1) The cost of control,

(2) The time required to achieve control,

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

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

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

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

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

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

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

1.1 Facility Description

Swanson Group Mfg. LLC (Swanson) owns and operates a veneer and plywood manufacturing facility located at 303 Mehlwood Lane, Glendale, Oregon 97442 (the facility). Swanson was among the 31 industrial facilities requested by the DEQ to conduct an Analysis. The facility currently operates under

Title V Operating Permit no. 10-0045-TV-01 (existing permit) issued by the DEQ on June 12, 2017. The facility is a major stationary source of criteria pollutants only.

The facility is located due north of Glendale city center and is situated in a small valley that is surrounded by significant topographical features in each cardinal direction. It is important to note that the nearest federal Class I area is the Kalmiopsis Wilderness Area, approximately 48.8 kilometers southwest of the facility.

1.2 Process Description

Raw green logs from off-site sources are delivered to the facility by trucks and are stored in the log yard. Received logs are cut to length prior to conditioning in log vats. After conditioning, the logs are peeled to produce thin layers of green veneer, which are then sold or sent for drying. There are three veneer dryers at the facility.

After drying is complete, a portion of the dried sheets is sent to the patch process for finishing. In the patch process, adhesives are applied to sorted sheets to produce plywood sheets. Plywood sheets are then sent to one of three presses for curing. Once curing is complete, rough-cut plywood is further finished by repairing board imperfections, sanding, and cutting to final product dimensions. Heat used by each press, the log vats, and each veneer dryer is generated by the Babcock and Wilcox Dutch-oven-type hogged fuel boiler (hogged fuel boiler).

2 APPLICABLE EMISSION UNITS

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

After emission rates were tabulated for each emissions unit, estimated emission rates for each pollutant were sorted from the highest emission rate to the lowest. The emission units collectively contributing up to 90 percent of the total facility emissions rate for a single pollutant were identified and selected for the Analysis.

This method of emission unit selection ensures that larger emission units are included in the Analysis. Larger emission units represent the likeliest potential for reduction in emissions that would contribute to a meaningful improvement in visibility at federal Class I areas. It would not be reasonable to assess many small emission units—neither on an individual basis (large reductions for a small source likely would not improve visibility and would not be cost effective), nor on a collective basis (the aggregate

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

emission rate would be no greater than 10 percent of the overall facility emissions rate, and thus not as likely to improve visibility at federal Class I areas, based solely on the relatively small potential overall emission decreases from the facility).

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

2.1 Sources of PM_{10} Emissions

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

2.1.1 Hogged Fuel Boiler (1PH)

Hogged fuel for use in the hogged fuel boiler is supplied primarily by off-site sources. However, residual bark, sanderdust, and plytrim generated on site are used when readily available. The hogged fuel boiler has a maximum rated heat input capacity of 125 million British thermal units per hour. Its rated design capacity is 75,000 pounds of steam per hour, which is used to provide heat for various types of equipment at the facility. Exhaust generated by operating the hogged fuel boiler is routed to a multiclone for control of coarse particulate emissions, then to a dry electrostatic precipitator (ESP) for control of fine particulate emissions. The hogged fuel boiler can also utilize process exhaust generated by operation of the three veneer dryers as a supplemental fuel source.

The hogged fuel boiler is subject to, and is required to comply with, Area Source Boiler Generally Available Control Technology (GACT) regulations, which are codified at Title 40 Code of Federal Regulations (CFR) 63 Subpart JJJJJJ, as introduced under Section 112(g) of the CAA. Based on USEPA guidance[2] provided to states for the Second Implementation Period, the USEPA believes that it is reasonable for states to exclude an emission source for further analysis if:

> For the purpose of [particulate matter (PM)] control measures, a unit that is subject to and complying with any CAA section 112 National Emission Standard for Hazardous Air Pollutants (NESHAP) or CAA section 129 solid waste combustion rule, promulgated or reviewed since July 31, 2013, that uses total or filterable PM as a surrogate for metals or has specific emission limits for metals. The NESHAPs are reviewed every 8 years and their emission limits for PM and metals reflects at least the maximum achievable control technology for major sources and the generally available control technology for area sources. It is unlikely that an analysis of control measures for a source meeting one of these NESHAPs would conclude that even more stringent control of PM is necessary to make reasonable progress.

Based on the USEPA guidance, the hogged fuel boiler was excluded from further evaluation in the Analysis. It is also important to note that the hogged fuel boiler is already well controlled for fine particulate emissions by the state-of-the-art dry ESP.

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

2.1.2 Veneer Dryer Fugitives (5VDa)

The veneer dryer fugitives emissions unit represents leaking emissions from seals, gaskets, and miscellaneous openings on the veneer dryers at the facility. Emissions from leaks are generated as fresh, green veneer is dried in each veneer dryer. The facility has a total of three veneer dryers (grouped in the existing permit as emission unit 5VD). Additional details describing the operation and size of each veneer dryer are presented in Section 2.1.2.1 for clarity.

Only PM_{10} emissions associated with the veneer dryer fugitives emissions unit (i.e., excluding emissions unit 5VD, point source veneer dryer emissions) meets the threshold of 90 percent contribution to the total facility PM_{10} emissions rate. However, each veneer dryer was recently rebuilt (within the last five years) in order to minimize the potential for fugitive emissions. There is also no reasonable way to capture fugitive emissions from veneer dryer leaks and route them to a downstream control device. Therefore, because of the recent reconstruction and the feasibility issues related to capturing and routing emissions, the veneer dryer fugitives emissions unit was excluded from further evaluation in the Analysis.

2.1.2.1 Veneer Dryers (5VD)

As stated above, there are three veneer dryers at the facility, which are used to dry green, freshly cut veneers to optimal moisture content depending on product specifications. Each veneer dryer at the facility is indirectly heated by steam generated by the hogged fuel boiler.

Veneer dryer no. 1 is a six-deck, two-zone Moore longitudinal dryer with a maximum drying capacity of 12,000 square feet per hour on a three-eighths-inch basis. Veneer dryer nos. 2 and 3 are four-deck, four-zone Moore jet dryers, each with a maximum drying capacity of 9,000 square feet per hour on a three-eighths-inch basis.

Process exhaust from the veneer dryers can be routed one of two ways, depending on the operating scenario. During operating scenario no. 1, process exhaust from the heated zones of each veneer dryer is routed through a heating coil, followed by a regenerative thermal oxidizer for control of volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions. During operating scenario no. 2, process exhaust from the heated zones of each veneer dryer is routed to the hogged fuel boiler combustion zone for control of VOC and HAP emissions.

It is important to note that the veneer dryer emissions unit did not meet the threshold of 90 percent contribution to the total facility PM_{10} emissions rate. Therefore, the veneer dryers were not included in the Analysis and are presented here only for reference.

2.1.3 Plywood Press Nos. 1 through 3 (P1, P2, and P3)

There are three plywood presses at the facility, each hydraulically driven and heated, typically up to 300 degrees Fahrenheit (°F) above ambient temperature, via steam produced by the hogged fuel boiler. Uncontrolled plywood press emissions are produced during pressing and as the press is released, and are emitted to atmosphere via nearby roof vents.

Press no. 1 is a Columbia batch press with a rated capacity of 7.5 batches per hour, which is equivalent to 270 sheets per hour. Press no. 2, also a Columbia batch press, has a rated capacity of 7.5 batches per hour, which is equivalent to 225 sheets per hour. Press no. 3 is a Williams and White 30-opening plywood press with a rated capacity of 20,000 square feet per hour.

Plywood presses emit fugitive 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. 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)[3] also includes fugitive emissions from other different types of process units in the same building. Nevertheless, estimated plywood press PM_{10} emissions are fairly small (less than 20 tons per year).

Plywood manufacturing facilities are subject to the NESHAP for Plywood and Composite Wood Products (PCWP) at 40 CFR 63, Subpart DDDD. Although veneer dryers are subject to standards, the USEPA determined that emissions from plywood presses were not amenable to capture and control and did not set any standards for these sources. The USEPA distinguished emissions control requirements for plywood presses from other reconstituted wood products presses (e.g., particleboard, oriented strand board, 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)."[4] By virtue of issuing emission control standards only for reconstituted wood products presses, the USEPA essentially determined that emissions capture and control is practicable for these types of presses, but not plywood presses. In the September 2019 PCWP NESHAP risk and technology review proposal, the USEPA did not propose to add standards for plywood presses.

The USEPA Reasonably Available Control Technology/Best Available Control Technology/ Lowest Achievable Emission Rate, or simply "RBLC," database includes no entries for plywood presses with add-on emissions controls. The USEPA'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.

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

[3] 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.

[4] USEPA, "National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products Manufacturing—Background Information for Final Standards." February 2004.

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, typically by 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, and emissions).

As detailed above, there are no technically feasible control options to capture or control plywood press PM_{10} emissions. Therefore, the plywood presses were excluded from further evaluation in the PM_{10} Analysis.

2.1.4 Pneumatic Conveyors (4CON)

The Pneumatic Conveyor emissions unit represents a collection of miscellaneous conveyors, cyclones, and target boxes used to handle and transport materials around the facility. Transported materials include chips, sawdust, plytrim, and sanderdust from both off-site sources and on-site activities. Individual process units, grouped within the Pneumatic Conveyor emissions unit, include the following:

- T&G saw cyclone no. 5
- T&G saw cyclone no. 4
- Veneer saw cyclone no. 3
- Hogged fuel blow pipe
- Target box no. 2
- Target box no. 3
- Sanderdust pneumatic conveyor

Only the emission units that meet the threshold of 90 percent contribution to the total facility PM_{10} emissions rate are listed above. Each emissions unit meeting the 90 percent contribution threshold is discussed in more detail in the following subsections.

2.1.4.1 T&G Saw Cyclone no. 5

T&G saw cyclone no. 5 (process unit CY5 in the existing permit) controls PM emissions generated by use of the T&G saw and detail saw in the main production building. PM emissions (i.e., plytrim residuals) enter into T&G saw cyclone no. 5 where centrifugal forces are imparted on larger-diameter particles in the conical chamber. The centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of plytrim residuals at the bottom of the cone. Collected plytrim residuals are then routed to T&G saw cyclone no. 4.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for the T&G saw cyclone are summarized in Section 2.4.

2.1.4.2 T&G Saw Cyclone no. 4

T&G saw cyclone no. 4 (process unit CY4 in the existing permit) routes collected plytrim residuals from T&G saw cyclone no. 5 to the downstream Plytrim Baghouse. The operation and control mechanisms of T&G saw cyclone no. 4 are identical to the descriptions presented in Section 2.1.4.1, except that collected plytrim residuals (i.e., particle fallout from the cone) are routed to the Plytrim Baghouse.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for T&G saw cyclone no. 4 are summarized in Section 2.4.

2.1.4.3 Veneer Saw Cyclone no. 3

The Veneer saw cyclone no. 3 (process unit CY3 in the existing permit) controls PM emissions generated by use of the core saw in the veneer storage building. The operation and control mechanisms of Veneer saw cyclone no. 3 are identical to the descriptions presented in Section 2.1.4.1, except that collected plytrim residuals (i.e., particle fallout from the cone) combine with plytrim residuals from T&G saw cyclone no. 4, and are routed to the Plytrim Baghouse.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for the Veneer saw cyclone no. 4 are summarized in Section 2.4.

2.1.4.4 Hogged Fuel Blow Pipe

The hogged fuel blow pipe (process unit BP1 in the existing permit) is a fully sealed, high-pressure blow line delivering hogged fuel across the facility. Hogged fuel is loaded into the blow pipe, using an enclosed chute with an airlock from the hog. Loaded hogged fuel is routed to either target box no. 2 or target box no. 3 (target box nos. 2 and 3 are discussed in more detail in the following subsections).

Based on communications with the facility, target box no. 3 is the actual point of emissions, and the hogged fuel blow pipe does not represent an emissions unit. Hence, the hogged fuel blow pipe is not an emissions unit and is shown incorrectly in the existing permit. Therefore, the hogged fuel blow pipe was excluded from further evaluation in the Analysis. Note that the permit error will be corrected in the next permitting cycle for the facility.

2.1.4.5 Target Box no. 2

Hogged fuel is routed primarily to target box no. 2 (process unit TB2 in the existing permit) via the hogged fuel blow pipe. Target box no. 2 is used to deliver hogged fuel into the hogged fuel silo. Based on communications with the facility, target box no. 2 is fully sealed to the top of the hogged fuel silo and does not emit. Hence, target box no. 2 is not an emissions unit and is shown incorrectly in the existing permit. Therefore, target box no. 2 was excluded from further evaluation in the Analysis. Note that the permit error will be corrected in the next permitting cycle for the facility.

2.1.4.6 Target Box no. 3

Hogged fuel is also routed to target box no. 3 (process unit TB3 in the existing permit) via the hogged fuel blow pipe. Target box no. 3 is used only to drop hogged fuel to a pile, adjacent to the hogged fuel loading area, when the silo is completely full. Exhaust parameters for target box no. 3 are presented in Section 2.4.

2.1.4.7 Sanderdust Pneumatic Conveyor

PM emissions (i.e., sanderdust) generated by the plywood sander are collected in two Torit baghouses. Collected sanderdust is loaded onto the sanderdust pneumatic conveyor (no process unit ID is presented in the existing permit) through rotary airlocks located at the bottom of each baghouse. The sanderdust pneumatic conveyor is used to route sanderdust to the downstream bin vent baghouse located atop the sanderdust truck loading bin. Collected sanderdust from the bin vent baghouse is dropped into the sanderdust truck loading bin via the attached rotary air lock. Exhaust parameters for the sanderdust pneumatic conveyor are presented in Section 2.4.

2.1.5 Materials Handling (2MT)

The Materials Handling emissions unit consists of miscellaneous equipment used to handle hogged fuel, bark, chips, sawdust, and sanderdust, including conveying these materials around the facility. Individual process units, grouped in the Materials Handling emissions unit, include the following:

- Hogged fuel pile-fuel loader
- Chip loading bin and associated pile
- Hogged fuel truck unloading ramp
- Hogged fuel and bark bins
- Plytrim truck loading bin

Only the emission units that meet the threshold 90 percent contribution to the total emissions rate for the facility are listed above. Each emission unit is described in more detail in the relevant section below.

2.1.5.1 Hogged Fuel Pile-Fuel Loader

A wheel loader, referred to in the existing permit as hogged fuel pile-fuel loader (process unit FL1), is used to transport hog fuel from the pile created by target box no. 3 and the hogged fuel truck dump area. The hogged fuel pile-fuel loader delivers stockpiled hogged fuel to the hog fuel conveyor, which feeds into the hogged fuel silo. Fugitive emissions are generated as the wheel loader transports material to the covered hogged fuel conveyor. Control of the fugitive particulate emissions generated by the wheel loader activities is considered to be technically infeasible. Therefore, the hogged fuel pile-fuel loader was excluded from further evaluation in the Analysis.

2.1.5.2 Chip Loading Bin and Associated Pile

There are three chip loading bins (process units B3, B4, and B5 in the existing permit) and a chip pile located in close proximity to the veneer production building. Two chip loading bins are fed by two open box chain conveyors, referred to in the existing permit as the chip conveyor and the bark conveyor. The third chip loading bin is fed by target box no. 1 (process unit TB1 in the existing permit). The actual point of emissions for the chip loading bins is limited to the dropping of chips into trucks (emissions generated by the chip and bark conveyors and target box no. 1 are accounted for elsewhere) and the cleanup of the associated pile.

As trucks drive under the chip loading bins, the bin door bottoms open, and green chips are loaded. The open sides of the bin doors and height of the truck sides provide adequate protection from wind, helping to limit fugitive emissions. Access material is dropped to the adjacent chip pile when trucks overload or have to make specific weight targets. This pile is periodically removed by a front-end loader, which feeds a nearby conveyor that is used to route chips to the hogged fuel bin (process unit B2 in the existing permit) as needed. It is important to note that the chips have high moisture contents resulting in minimal emissions of fine particulate.

The loading of trucks via the chip loading bins and the process of clearing the pile represent sources of fugitive particulate emissions. Control of fugitive particulate emissions generated by each emissions unit is considered to be technically infeasible, since capture and collection cannot reasonably be achieved without altering truck and/or worker access (e.g., creating safety concerns). Based on the fugitive nature of each emissions unit, the chip loading bins and associated pile emissions unit were excluded from further evaluation in the Analysis.

2.1.5.3 Hogged Fuel Truck Unloading Ramp

The hogged fuel truck unloading ramp (process unit HFR1 in the existing permit) is used for unloading hogged fuel delivered in semi-trucks from off-site sources. As the semi-trucks drive onto the unloading ramp, hogged fuel is dumped from the trucks to an adjacent hogged fuel storage pile. Enclosure and control of fugitive particulate emissions is considered to be technically infeasible since the semi-trucks dump from the unloading ramp and adequate space is required for access and unloading activities. Therefore, the hogged fuel truck unloading ramp was excluded from further evaluation in the Analysis.

2.1.5.4 Hogged Fuel and Bark Bins

The hogged fuel and bark bins (process unit B2 in the existing permit) are used to load material into outbound trucks near the veneer production building. Both bins are used only when the hogged fuel blow pipe is down for maintenance purposes. The normal operation is to route bark through the hogged fuel blow pipe to the hogged fuel silo or pile via target box nos. 2 and 3, respectively.

The hogged fuel and bark bin can also be supplied green chips by the adjacent conveyor. This conveyor receives green chips from the front-end loader used to periodically to clean up the pile identified in Section 2.1.5.2.

Similar to Section 2.1.5.2, the loading of trucks, via the hogged fuel and bark bins, represents a source of fugitive particulate emissions. Control of fugitive particulate emissions generated by use of the bins is considered to be technically infeasible, since capture and collection cannot reasonably be achieved. Based on the fugitive nature of the emissions unit and the infrequent use of the bins, the hogged fuel and bark bins emissions unit was excluded from further evaluation in the Analysis.

2.1.5.5 Plytrim Truck Loading Bin

The plytrim truck loading bin (process unit B8 in the existing permit) is used to drop plytrim residuals into outbound trucks to be hauled off site. Plytrim residuals are delivered to the bin via an airlock attached to the Plytrim Baghouse located directly on top of the plytrim truck loading bin.

Similar to the description provided in Section 2.1.5.2, the loading of trucks, via the plytrim truck loading bin, represents a source of fugitive particulate emissions. Control of fugitive particulate emissions generated by use of the bins is considered to be technically infeasible, since capture and collection cannot reasonably be achieved without altering truck and/or worker access (e.g., creating safety concerns). Therefore, the plytrim truck loading bin was excluded from further evaluation in the Analysis.

2.1.6 Paved and Unpaved Roads (6WE)

The paved roads emissions unit is representative of fugitive emissions generated by vehicle traffic on paved and unpaved roads on facility property. The facility conducts periodic sweeping and watering on on-site roads as preventative dust-control measures. Further control of the paved roads emissions unit is considered to be technically infeasible since capture and collection of emissions cannot reasonably be achieved. Therefore, the paved roads emissions unit was excluded from further evaluation in the Analysis.

2.2 Sources of NO_X Emissions

A summary of the selected emission units and associated NO_X emission rates to be evaluated in the Analysis is presented in Table 2-2 (attached). As shown in the table, only the hogged fuel boiler is included as a source for further evaluation in the Analysis. See Section 2.1.1 for a description of the hogged fuel boiler emissions unit and associated existing control devices.

2.3 Sources of SO_2 Emissions

A summary of the selected emission units and associated SO_2 emission rates to be evaluated in the Analysis is presented in Table 2-3 (attached). As shown in the table, only the hogged fuel boiler is included as a source for further evaluation in the Analysis. See Section 2.1.1 for a description of the hogged fuel boiler emissions unit and associated existing control devices.

2.4 Emission Unit Exhaust Parameters

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

3 REGIONAL HAZE FOUR FACTOR ANALYSIS METHODOLOGY

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

3.1 Step 1: Determine Emission-Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

Section 2 details the method for determining the emission units and emission rates to be used in the Analysis. Potential to emit emission rates were obtained from the existing permit review report.

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

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

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

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

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

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

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

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

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

3.5.1 Step 6: Characterize Remaining Useful Life of Source (Statutory Factor 4)

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

4 PM_{10} ANALYSIS

The Analysis for PM_{10} emissions follows the six steps previously described in Section 0.

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

4.1.1 Baghouses

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

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

Certain process limitations can affect the operation of baghouses in some applications. For example, exhaust streams with very high temperatures (i.e., greater than 500°F) may require specially formulated filter materials and/or render baghouse control infeasible. Additional challenges include the particle characteristics, such as materials that are "sticky" and tend to impede the removal of material from the filter surface. Exhaust gases that exhibit corrosive characteristics may also impose limitations on the effectiveness of baghouses. There is also the concern for combustible wood dust creating a potential spark hazard within the baghouse (i.e., generating embers within the collector). As a result, a spark detection/extinguishment system will be necessary in certain wood product applications. In wood products applications it is expected that particle characteristics, specifically particle and exhaust moisture content, may limit the feasibility on implementation. However, for some sources, baghouses are considered technically feasible.

4.1.2 Wet Venturi Scrubbers

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

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

As wet scrubbers become saturated with a pollutant it is necessary to discharge (blowdown) some scrubber liquid and add fresh water. A water treatment system of suitable size is necessary to handle the scrubber blowdown. The Glendale facility is not connected to a city sewer system. The facility is reliant on a septic system. The amount of scrubber blowdown that would be created for an appropriately sized wet scrubber would likely overwhelm the septic system.

As a result, a wet scrubber system is considered technically infeasible for this facility location.

4.1.3 Electrostatic Precipitator

ESPs are used extensively for control of PM emissions. An ESP is a particulate control device that uses electrical force to move particles entrained with a gas stream onto collection surfaces. An electrical charge is imparted on the entrained particles as they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the corona that charges the particles, thereby allowing for their collection on the oppositely charged collector walls. Due to these electrical forces, there is high concern for combustible wood dust creating a potential spark hazard within an ESP (i.e., generating embers within the collector). As a result, a spark detection/extinguishment system will be necessary in order to mitigate the potential for deflagration events, at a minimum. Prior to an actual installation, a vendor evaluation will be necessary to determine if there are site-specific hazards that will preclude this control option due to safety concerns. Under the current timeline, a vendor inspection was not possible by an outside ESP vendor prior to submitting this Analysis.

In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. Instead of the collection hoppers used by dry ESPs, wet ESPs utilize a drainage system and water treatment of some sort. In dry ESPs, the collectors are knocked, or "rapped," by various mechanical means to dislodge the collected particles, which slide downward into a hopper for collection.

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

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern. The effluent wastewater and wet sludge stream created by the wet ESP requires the operating facility to have an appropriately sized water treatment system and subsequent disposal system in place. The overall amount of wastewater generated by operating in the wet ESP may likely overwhelm the septic system.

As a result, while a dry ESP is considered a technically feasible control device option, a wet ESP is considered technically infeasible for this facility location.

4.2 Step 2—Selection of Emissions

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

4.3 Step 3—Characterizing Cost of Compliance

Tables 4-2 and 4-3 (attached) present the detailed cost analyses of the technically feasible PM_{10} control technologies included in the Analysis. Note the sanderdust pneumatic conveyor is already controlled by the bin vent baghouse and therefore, was not included in Table 4-2 (e.g., baghouse cost effectiveness derivation table). A summary of the cost of compliance, expressed in $/ton, is shown below in Table 4-1:

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

Emissions Unit	Process Unit ID	Cost of Compliance ($/ton)	
		BH	Dry ESP
Trim Saw Cyclone #5	CY5	$12,818	$14,459
T&G Saw Cyclone #4	CY4	$23,234	$26,214
Veneer Saw Cyclone #3	CY3	$58,414	$65,500
Target Box #3	TB3	$78,615	$94,268
Sanderdust Pneumatic Conveyor	--	--	$101,309

4.4 Step 4—Characterizing Time Necessary for Compliance

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

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

4.5.1 Energy Impacts

Energy impacts can include electricity and/or supplemental fuel used by a control device. Electricity use can be substantial for large projects if the control device uses large fans, pumps, or motors. Similarly, processes based on thermal oxidation may use significant amounts of fossil fuels, which can lead to economic impacts as well as climate change impacts.

Baghouse control systems require significant electricity use to operate the powerful fans required to overcome the pressure drop across the filter bags. Dry ESPs are expected to require even more electricity than baghouses, since high-voltage electricity is required for particle collection and removal. Dry ESPs also require powerful fans to maintain exhaust flow through the system.

4.5.2 Environmental Impacts

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

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

4.6 Step 6—Characterize Remaining Useful Life

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

5 NO_X ANALYSIS

The Analysis for NO_X emissions follows the six steps previously described in Section 0.

5.1 Step 1—Determine NO_X Control Measures for Consideration

5.1.1 Selective Non-Catalytic Reduction

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

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

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

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

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

5.1.2 Selective Catalytic Reduction and Hybrid Systems

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

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

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

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

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

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

5.1.3 Low NOx Burner

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

Combustion in hogged fuel boilers commonly occurs on grates, including the Dutch-oven-type hogged fuel boiler at the facility, and does not utilize the types of burners typically employed for low NO_X burner applications. Potential reductions in NO_X emissions from these types of boilers (without add-on controls) are limited by the boiler furnace geometry, air flow controls, and burner zone stoichiometry, making retrofitting applications difficult. The hogged fuel boiler at the facility is regularly inspected for fine-tuning and/or routine maintenance of the boiler systems. As a result, it is expected that the hogged fuel boiler is already optimized for NO_X performance.

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

5.2 Step 2—Selection of Emissions

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

5.3 Step 3—Characterizing Cost of Compliance

Table 5-1 presents the detailed cost analysis of the only technically feasible NO_X control technology (e.g., SNCR) included in the Analysis. The cost estimate is based on a heated urea-based injection system, instead of aqueous ammonia injection, because of storage safety concerns. The cost of compliance for the SNCR installation on the hogged fuel boiler is $12,265 per ton of NO_X emissions controlled.

5.4 Step 4—Characterizing Time Necessary for Compliance

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

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

5.5.1 Energy Impacts

Direct energy impacts will result from the use of SNCR control systems. Energy use (e.g. electricity use) is limited to the operation of pumps for urea injection into the SNCR and the heating of the urea storage tank. As a result, direct energy impacts are expected to be minimal. SNCR systems also consume fossil fuels, primarily natural gas, during the ammonia production process, and in order to mitigate the increased moisture loads caused by the urea injection in the flue gas.

5.5.2 Environmental Impacts

SNCR units require the use of urea (or aqueous ammonia) injection in the exhaust stream. Any unreacted excess ammonia in the exhaust stream (i.e., ammonia slip) will be released to the atmosphere. Ammonia slip to the atmosphere is a contributor to fine particle formation, which further exacerbates the regional haze issue; ammonia is also considered to be a toxic air contaminant with associated human health risks, and is regulated under the Cleaner Air Oregon Program. Hence, there is a trade-off between maximizing NO_X emission reductions and minimizing the potential for ammonia slip.

5.6 Step 6—Characterize Remaining Useful Life

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

6 SO_2 ANALYSIS

The Analysis for SO_2 emissions follows the six steps previously described in Section 0.

6.1 Step 1—Determine SO_2 Control Measures for Consideration

6.1.1 Dry Sorbent Injection

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

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

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

Dry sorbent injection systems introduce PM emissions into the exhaust stream, as mentioned above. This will cause increases to the particulate inlet loading of downstream particulate control devices. For retrofit applications, it is likely that modification of the downstream existing particulate control device will be necessary in order to accommodate the increased particulate inlet loading. It is anticipated that this increased loading cannot be accommodated solely through modifications to the existing control device. Assuming that this is the case, additional particulate controls will be required, resulting in cost increases and further energy and environmental impacts.

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

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

6.2 Step 2—Selection of Emissions

See Sections 2.3 for a description of the SO_2 emission units and emission rates selected in the Analysis.

6.3 Step 3—Characterizing Cost of Compliance

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

6.4 Step 4—Characterizing Time Necessary for Compliance

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

6.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

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

6.6 Step 6—Characterize Remaining Useful Life

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

7 CONCLUSION

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

LIMITATIONS

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

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

TABLES

Table 2-1
PM_{10} Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit(s) (1)	Emission Unit ID (1)	Current PM_{10} Control Technology (1)	Annual PM_{10} Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Trim Saws Cyclone #5 (CY5)	4CON	–	25.8	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hogged Fuel Boiler	1PH	Multiclone & Dry ESP	19.3	No	Source is directly regulated for filterable PM as a surrogate for metal under Area Source Boiler GACT, which became effective after July 31, 2013. Therefore, this source meets EPA guidance for no further analysis.	–
Hog Fuel Pile-Fuel Loader (FL1)	2MT	–	19.1	No	Fugitive source.	–
Chip Loading Bin (B3, B4, and B5) and Pile	2MT	–	17.4	No	Fugitive source.	–
Plywood Presses	P1, P2, P3	–	16.0	No	Accessibility and design limitations make control technically infeasible.	–
T&G Saw Cyclone #4 (CY4)	4CON	–	14.2	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hog Fuel Truck Unloading Ramp (HFR1)	2MT	–	11.7	No	Fugitive source.	–
Paved Roads	6WE	Sweeping & Watering	10.3	No	Fugitive source.	–
Veneer Dryers Fugitives	5VDa	–	9.9	No	Fugitive source and recent reconstruction to minimize fugitives.	–
Hog Fuel and Bark Bins (B2)	2MT	–	7.5	No	Fugitive source and minimal use.	–
Plytrim Truck Loading Bin (B8)	2MT	–	6.0	No	Fugitive source.	–
Veneer Saw Cyclone #3 (CY3)	4CON	–	6.0	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hog Fuel Blow Pipe (BP1)	4CON	–	4.9	No	Not an emissions unit (to be corrected with next permitting cycle).	–
Target Box #2 (TB2)	4CON	–	3.4	No	Not an emissions unit (to be corrected with next permitting cycle).	–
Target Box #3 (TB3)	4CON	–	3.4	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Sanderdust Pneumatic Conveyer	4CON	Baghouse	3.1	Yes	–	Wet Venturi Scrubber, Electrostatic Precipitator
All other sources (includes conveyors, veneer dryer RTO, target boxes, truck loading bins, glue mixers, aggregate insignificant)	Varies	Varies by emission unit	22.0	No	This collection of emission units falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	–

REFERENCES:
(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.
(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

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Table 2-2
NO_x Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit [1]	Emission Unit ID [1]	Current NO_x Control Technology [1]	Annual NO_x Emissions [2] (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Hogged Fuel Boiler	1PH	--	71.2	Yes	--	Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Low-NOx Burners
Veneer Dryers	5VD	--	0.4	No	This emission unit falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

Table 2-3
SO_2 Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit [1]	Emission Unit ID [1]	Current SO_2 Control Technology [1]	Annual SO_2 Emissions [2] (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Hogged Fuel Boiler	1PH	–	3.9	Yes	–	Dry Sorbent Injection
Veneer Dryers	5VD	–	0.04	No	This emission unit falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	–

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

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Table 2-4
Emissions Unit Input Assumptions and Exhaust Parameters
Swanson Group Mfg. LLC—Glendale, Oregon

Emissions Unit ID [1]	Emissions Unit Description [1]	Process Unit ID	Control Evaluation Proposed? (Yes/No)			Heat Input Capacity (MMBtu/hr)	Exhaust Parameters		
			PM_{10} [2]	NO_X [3]	SO_2 [4]		Exit Temperature (°F)	Exit Flowrate (acfm)	Exit Flowrate (scfm)
1PH	Hogged Fuel Boiler	ESP	No	Yes	Yes	125 [1]	417 [5]	69,633 [5]	31,743 [5]
4CON	Trim Saws Cyclone #5	CY5	Yes	No	No	–	70 [6]	11,500 [7]	10,927 [a]
4CON	T&G Saw Cyclone #4	CY4	Yes	No	No	–	70 [6]	11,500 [7]	10,927 [a]
4CON	Veneer Saw Cyclone #3	CY3	Yes	No	No	–	70 [6]	15,000 [7]	14,253 [a]
4CON	Target Box #3	TB3	Yes	No	No	–	70 [6]	2,300 [7]	2,185 [a]
4CON	Sanderdust Pneumatic Conveyer	–	Yes	No	No	–	70 [6]	1,200 [7]	1,140 [a]

NOTES:

acfm = actual cubic feet per minute.

ESP = electrostatic precipitator.

ft/sec = feet per second.

MMBtu/hr = million British thermal units per hour.

scfm = standard cubic feet per minute.

(a) Exit flowrate (scfm) = (exit flowrate [acfm]) x (1 - [6.73E-06] x [facility elevation above sea level {ft}])$^{5.258}$ x (530) / (460 + [exit temperature {°F}])

Facility elevation above sea level (ft) = 1,437 (8)

REFERENCES:

(1) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

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

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

(4) See Table 2-3, SO_2 Evaluation for Regional Haze Four Factor Analysis. Each SO_2 control technology is considered to be technically infeasible.

(5) See source test report, Table 3 "Hog Fuel Boiler," prepared by Bighorn Environmental Air Quality dated April 1, 2014.

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

(7) Information provided by Swanson Group Mfg. LLC.

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

Table 3-1
Utility and Labor Rates
Swanson Group Mfg. LLC—Glendale, Oregon

Parameter	Value (units)		
FACILITY OPERATIONS			
Annual Hours of Operation	8,760	(hrs/yr)	(1)
Annual Days of Operation	365	(day/yr)	(1)
Daily Hours of Operation	24	(hrs/day)	(1)
UTILITY COSTS			
Electricity Rate	0.079	($/kWh)	(2)
Natural Gas Rate	2.69	($/MMBtu)	(3)
Water Rate	4.58	($/Mgal)	(a)
Wood Fuel Rate	25.0	($/BDT)	(3)
Landfill Disposal Rate	60.0	($/ton)	(3)
Compressed Air Rate	0.0039	($/Mscf)	(b)
LABOR COSTS			
Maintenance Labor Rate	36.48	($/hr)	(3)
Operating Labor Rate	24.26	($/hr)	(3)
Supervisory Labor Rate	27.99	($/hr)	(3)
Operating Labor Hours per Shift	2	(hrs/shift)	(7)
Maintenance Labor Hours per Shift	1	(hrs/shift)	(7)
Typical Shifts per Day	3	(shifts/day)	(8)

NOTES:

BDT = bone dry ton.

Mgal = thousand gallons.

MMBtu = million British thermal units.

Mscf = thousand standard cubic feet.

MWh = megawatt-hour.

(a) Water cost ($-2019/Mgal) = (water cost [$-2018/Mscf]) / (2018 CEPCI annual index) x (2019 CEPCI annual index)

Water cost ($-2018/gal) =	4.55	(4)
1998 CEPCI annual index =	389.5	(5)
2019 CEPCI annual index =	607.5	(5)

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

Compressed air cost ($-1998/Mscf) =	0.0025	(6)
1998 annual CEPCI index =	389.5	(5)
2019 annual CEPCI index =	607.5	(5)

REFERENCES:

(1) Assumes continuous annual operation.

(2) Information provided by Swanson Group Mfg. LLC. Assumes industrial average rate for Pacific Power.

(3) Information provided by Swanson Group Mfg. LLC.

(4) Water and sewer costs obtained from "50 Largest Cities Water & Wastewater Rate Survey" prepared Black & Veatch Management Consulting, LLC dated 2018-2019. See exhibit B, Figure 19. Note this reference was provided in the USEPA Air Pollution Control Cost Manual, Section 3, Chapter 1 "Carbon Adsorbers" calculation spreadsheet.

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

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

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

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

Table 4-2
Cost Effectiveness Derivation for Baghouse Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Process Unit ID	Emissions Unit Description	Input Parameters: Exhaust Flowrate [1] (acfm)	Input Parameters: PM_{10} Annual Emissions Estimate [2] (tons/yr)	Pollutant Removed by Control Device [a] (tons/yr)	Operating Parameter: Electrical Requirements [4] (kW)	Operating Parameter: Number of Filter Bags Required [4]
CY5	Trim Saws Cyclone #5	11,500	25.8	25.6	60.4	152
CY4	T&G Saw Cyclone #4	11,500	14.2	14.1	60.4	152
CY3	Veneer Saw Cyclone #3	15,000	6.0	5.91	73.1	196
TB3	Target Box #3	2,300	3.4	3.39	25.2	34

Process Unit ID	Emissions Unit Description	Direct Costs: Purchased Equipment Cost: Basic Equip./Services Cost [4]	Direct Costs: Purchased Equipment Cost: Total [b]	Direct Costs: Total Direct Cost [c]	Total Indirect Costs [d]	Total Capital Investment [e]	Capital Recovery Cost (CRC): Control Device (CRC) [f]	Capital Recovery Cost (CRC): Replacement Parts: Filter Bag Cost [4]	Capital Recovery Cost (CRC): Replacement Parts: Bag Labor Cost [h]	Capital Recovery Cost (CRC): Replacement Parts: Filter Bag (CRC) [i]
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_0	C_B	C_L	CFC_B
CY5	Trim Saws Cyclone #5	$105,990	$125,068	$232,618	$56,281	$288,899	$22,693	$2,293	$1,386	$1,083
CY4	T&G Saw Cyclone #4	$105,990	$125,068	$232,618	$56,281	$288,899	$22,693	$2,293	$1,386	$1,083
CY3	Veneer Saw Cyclone #3	$113,861	$134,355	$248,778	$60,460	$309,238	$24,291	$2,948	$1,788	$1,394
TB3	Target Box #3	$53,971	$63,686	$125,814	$28,659	$154,473	$12,134	$506	$310	$240

Process Unit ID	Emissions Unit Description	Direct Annual Costs: Operating Labor: Operator Cost [j]	Direct Annual Costs: Operating Labor: Supervisor Cost [k]	Direct Annual Costs: Maintenance: Labor Cost [l]	Direct Annual Costs: Maintenance: Material Cost [14]	Direct Annual Costs: Utilities: Electricity Cost [l]	Direct Annual Costs: Utilities: Compressed Air Cost [m]	Direct Annual Costs: Utilities: Landfill Cost [n]	Total Direct Annual Costs [14]	Total Indirect Annual Costs [o]	Total Annual Cost [p]	Annual Cost Effectiveness [q]
USEPA COST MANUAL VARIABLE		--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
CY5	Trim Saws Cyclone #5	$53,129	$7,969	$39,946	$39,946	$41,747	$23,569	$1,534	$208,923	$118,843	$327,766	$12,818
CY4	T&G Saw Cyclone #4	$53,129	$7,969	$39,946	$39,946	$41,747	$23,569	$845	$208,234	$118,843	$327,077	$23,234
CY3	Veneer Saw Cyclone #3	$53,129	$7,969	$39,946	$39,946	$50,509	$30,742	$355	$223,989	$121,254	$345,244	$58,414
TB3	Target Box #3	$53,129	$7,969	$39,946	$39,946	$17,421	$4,714	$203	$163,568	$102,907	$266,475	$78,615

See notes and formulas on following page.

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Table 4-2 (Continued)
Cost Effectiveness Derivation for Baghouse Installation
Swanson Group Mfg. LLC—Glendale, Oregon

NOTES:

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

Baghouse control efficiency (%) = 99.0 (3)

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

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

Site preparation cost, SP ($) = 15,000 (6)
Building cost, Bldg. ($) = 0 (7)

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

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

(f) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (8)

Control device capital recovery factor = 0.0786 (g)

(g) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^[economic life (yrs)]) / ([1 + (interest rate [%] / 100)]^[economic life (yrs)] - 1); see reference (9).

Interest rate (%) = 4.75 (10)
Baghouse economic life (yr) = 20 (11)
Filter bag economic life (yr) = 4 (12)

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

Total time required to change one bag (min/bag) = 15 (13)
Maintenance labor rate ($/hr) = 36.48 (14)

(i) Filter bag capital recovery cost ($) = ([initial filter bag cost ($)] x [1.08] + [bag replacement labor cost ($)]) x (filter bag capital recovery factor); see reference (13).

Filter bag capital recovery factor = 0.2804 (g)

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

Operating labor hours per shift [hrs/shift] = 2 (14)
Maintenance labor hours per shift [hrs/shift] = 1 (14)
Shifts per day (shifts/day) = 3 (14)
Annual days of operation (days/yr) = 365 (14)
Operator labor rate ($/hr) = 24.26 (14)
Maintenance labor rate ($/hr) = 36.48 (14)

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

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

Electricity rate ($/kWh) = 0.079 (14)
Annual hours of operation (hrs/yr) = 8,760 (14)

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

Compressed air rate ($/Mscf) = 0.0039 (14)
Annual hours of operation (hrs/yr) = 8,760 (14)

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

Landfill disposal rate ($/ton) = 60.0 (14)

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

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

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

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM$_{10}$ Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-025) for baghouse (fabric filter), pulse-jet cleaned type issued July 15, 2003. Assumes minimum typical new equipment design efficiency.
(4) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. In the quote, costs and equipment requirements for three differently sized baghouses (5,000 cfm, 20,000 cfm, and 50,000 cfm) are presented. For the smallest exhaust flowrate above (MC4), these quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, installation of equipment, all concrete work (including excavation, engineering, plumbing, electrical construction), building/foundation upgrades, and permitting or licensing. The cost for an add-on spark detection/extinguishment system is included due to concerns about combustible wood dust.
(5) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See Table 1.9 "Capital Cost Factors for Fabric Filters." The 1.18 factor includes instrumentation, sales tax, and freight.
(6) Information provided by Swanson Group Mfg. LLC. The site preparation cost only accounts for concrete foundation work (approximately $600 per cubic yard and an estimated pad size of 15-ft by 15-ft by 1-ft deep) ,and obtaining a professional engineer stamp. The pad size estimate does not represent an engineering design value and requires further analysis.
(7) Conservatively assumes no costs associated with site preparation or building requirements.
(8) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(9) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(10) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(11) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.2.
(12) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. Typical bag filter life is 4 years.
(13) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.1.4.
(14) See Table 3-1, Utility and Labor Rates.
(15) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Process Unit ID	Emissions Unit Description	Input Parameters: Exhaust Flowrate (acfm)	Input Parameters: Exhaust Flowrate (scfm)	Input Parameters: PM_{10} Annual Emissions Estimate (tons/yr)	Pollutant Removed by Control Device (tons/yr)	Operating Parameter: System Pressure Drop (inch w.c.)	Operating Parameter: Total Collection Plate Area Estimate (ft^2)	Operating Parameter: ESP Inlet Grain Loading (gr/ft^3)
CY5	Trim Saws Cyclone #5	11,500	10,927	25.8	25.6	6.00	4,371	0.060
CY4	T&G Saw Cyclone #4	11,500	10,927	14.2	14.1	6.00	4,371	0.033
CY3	Veneer Saw Cyclone #3	15,000	14,253	6.0	5.91	6.00	5,701	0.011
TB3	Target Box #3	2,300	2,185	3.4	3.39	6.00	874	0.040
--	Sanderdust Pneumatic Conveyer	1,200	1,140	3.1	3.096	6.00	456	0.069

Process Unit ID	Emissions Unit Description	Direct Costs: Purchased Equipment Cost: Basic Equip./Services Cost	Direct Costs: Purchased Equipment Cost: Total	Direct Costs: Total Direct Cost	Total Indirect Costs	Total Capital Investment	Capital Recovery Cost of Control Device	Direct Annual Costs: Operating Labor: Operator Cost	Direct Annual Costs: Operating Labor: Supervisor Cost	Direct Annual Costs: Operating Labor: Coordinator Cost	Direct Annual Costs: Maintenance: Labor Cost	Direct Annual Costs: Maintenance: Material Cost	Direct Annual Costs: Utilities: Fan Electricity Cost	Direct Annual Costs: Utilities: Oper. Electricity Cost	Direct Annual Costs: Utilities: Compressed Air Cost	Direct Annual Costs: Utilities: Landfill Cost	Total Direct Annual Costs	Total Indirect Annual Costs	Total Annual Cost	Annual Cost Effectiveness
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_p	--	--	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
CY5	Trim Saws Cyclone #5	$573,294	$676,487	$1,157,511	$385,597	$1,543,108	$121,212	$53,129	$7,969	$17,710	$6,416	$6,765	$8,632	$5,861	$23,569	$1,551	$131,602	$238,130	$369,731	$14,459
CY4	T&G Saw Cyclone #4	$573,294	$676,487	$1,157,511	$385,597	$1,543,108	$121,212	$53,129	$7,969	$17,710	$6,416	$6,765	$8,632	$5,861	$23,569	$854	$130,904	$238,130	$369,034	$26,214
CY3	Veneer Saw Cyclone #3	$594,367	$701,353	$1,199,037	$399,771	$1,598,809	$125,587	$53,129	$7,969	$17,710	$6,416	$7,014	$11,259	$7,644	$30,742	$359	$142,241	$244,882	$387,123	$65,500
TB3	Target Box #3	$517,902	$611,124	$1,048,355	$348,341	$1,396,695	$109,711	$53,129	$7,969	$17,710	$6,416	$6,111	$1,726	$1,172	$4,714	$206	$99,153	$220,380	$319,533	$94,268
--	Sanderdust Pneumatic Conveyer	$511,279	$603,309	$1,035,303	$343,886	$1,379,189	$108,336	$53,129	$7,969	$17,710	$6,416	$6,033	$901	$612	$2,459	$188	$95,417	$218,258	$313,675	$101,309

See notes and formulas on following page.

Table 4-3 (Continued)
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Swanson Group Mfg. LLC—Glendale, Oregon

NOTES:

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

Control efficiency (%) =	99.0	(3)

(b) Total collection plate area estimate (ft²) = (average specific collection area [ft²/1,000 scfm]) x (exhaust flowrate [scfm])

Average specific collection area (ft²/1,000 scfm) =	400	(3)

(c) ESP inlet grain loading (gr/ft³) = (PM_{10} annual emissions estimate [tons/yr]) x (2,000 lb/ton) x (7,000 gr/lb) / (exhaust flowrate [acfm]) x (hr/60 min) / (annual hours of operation [hrs/yr])

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

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

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

Site preparation cost, SP ($) =	27,778	(8)
Building cost, Bldg. ($) =	0	(9)

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

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

(h) Capital recovery cost of control device($) = (total capital investment [$]) x (control device capital recovery factor); see reference (10).

Control device capital recovery factor =	0.0786	(i)

(i) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^[economic life (yrs)]) / ([1 + (interest rate [%] / 100)]^[economic life (yrs)] - 1); see reference (11).

Interest rate (%) =	4.75	(12)
Dry ESP economic life (yr) =	20	(13)

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

Operator labor rate ($/hr) =	24.26	(6)
Operating labor hours per shift (hrs/shift) =	2	(6)
Shifts per day (shifts/day) =	3	(6)
Annual days of operation (days/yr) =	365	(6)

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

(l) Coordinator labor cost ($) = (1/3) x (operator labor cost [$]); see reference (14).

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

Maintenance labor cost ($-1999)	4,125	(14)
1999 annual chemical engineering plant cost index =	390.6	(15)
2019 annual chemical engineering plant cost index =	607.5	(15)

(n) Maintenance material cost ($) = (0.01) x (total purchased equipment cost [$]); see reference (14).

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

Annual hours of operation (hrs/yr) =	8,760	(6)
Electricity rate ($/kWh) =	0.079	(6)

(p) Annual operating power electricity cost ($) = (1.94E-03) x (total collection plate area estimate [ft²]) x (annual hours of operation [hrs/yr]) x (electricity rate [$/kWh])

Annual hours of operation (hrs/yr) =	8,760	(6)
Electricity rate ($/kWh) =	0.079	(6)

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

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

(r) Annual landfill cost ($) = (4.29E-06) x (ESP inlet grain loading [gr/ft³]) x (annual hours of operation [hrs/yr]) x (exhaust flowrate [acfm]) x (landfill disposal rate [$/ton]); see reference (14).

Annual hours of operation (hrs/yr) =	8,760	(6)
Landfill disposal rate ($/ton) =	60.0	(6)

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

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

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

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-028) for dry electrostatic precipitator, wire-plate type issued July 15, 2003. Assumes the typical collection area and minimum new equipment design control efficiency.
(4) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.2.3. Assumes the average system (including ductwork and collection system) pressure drop of range provided.
(5) PPC Industries Quotation no. 18048/18049 (Revision 0) dated September 12 and 13, 2018. MFA obtained two separate costs and equipment requirements for dry ESPs sized at 21,000 acfm and 51,000 acfm. For the smallest exhaust flowrate above (MC4), the quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, freight, mechanical construction, electrical work, excavation, building/foundation upgrades, and permitting or licensing. The cost for an add-on spark detection/extinguishment system is included due to concerns about combustible wood dust.
(6) See Table 3-1, Utility and Labor Rates.
(7) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.16 "Capital Cost Factors for ESPs."
(8) Information provided by Swanson Group Mfg. LLC. The site preparation cost only accounts for concrete foundation work (approximately $600 per cubic yard and an estimated pad size of 20-ft by 20-ft by 2-ft deep) ,and obtaining a professional engineer stamp. The pad size estimate does not represent an engineering design value and requires further analysis.
(9) Conservatively assumes no costs associated with site preparation or building requirements.
(10) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(11) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(12) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(13) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.4.2.
(14) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.21.
(15) See Chemical Engineering magazine, chemical engineering plant cost index section for annual indices.

Table 5-1
Cost Effectiveness Derivation for Selective Non-Catalytic Reducer Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters: Heat Input Capacity [1] (MMBtu/hr)	Input Parameters: Uncontrolled NO_x Emissions Estimate: Hourly [a] (lb/hr)	Input Parameters: Uncontrolled NO_x Emissions Estimate: Annual [3] (tons/yr)	Input Parameters: Uncontrolled NO_x Emissions in Flue Gas [b] (lb/MMBtu)	Pollutant Removed by Control Device: Hourly [c] (lb/hr)	Pollutant Removed by Control Device: Annual [d] (tons/yr)	Normalized Stoichiometric Ratio [e]	Operating Parameters: Reagent Mass Consumption [f] (lb/hr)	Operating Parameters: Reagent Solution Flowrate [g] (gal/hr)	Operating Parameters: Power Demand [h] (kW)	Operating Parameters: Water Demand [i] (gal/hr)	Operating Parameters: Additional Fuel Usage [j] (MMBtu/hr)
USEPA COST MANUAL VARIABLE		Q_B	--	--	$NO_{X_{in}}$	--	--	NSR	$m_{reagent}$	q_{sol}	P	q_{water}	ΔFuel
1PH	Hogged Fuel Boiler	125	16.3	71.2	0.13	4.06	17.8	1.85	19.6	4.13	36.4	18.8	0.16

Emissions Unit ID	Emissions Unit Description	Direct Cost: Capital Cost [k]	Indirect Cost: Balance of Plant Cost [l]	Total Capital Investment [m]	Capital Recovery Cost of Control Device [n]	Direct Annual Costs: Maintenance Labor and Material Cost [p]	Direct Annual Costs: Reagent Usage [q]	Direct Annual Costs: Utilities: Electricity Cost [s]	Direct Annual Costs: Utilities: Water Usage Cost [t]	Direct Annual Costs: Utilities: Fuel Additive Cost [u]	Direct Annual Costs: Utilities: Ash Disposal Cost [v]	Total Direct Annual Costs [27]	Total Indirect Annual Costs [w]	Total Annual Cost [x]	Annual Cost Effectiveness [y]
USEPA COST MANUAL VARIABLE		$SNCR_{cost}$	BOP_{cost}	TCI	CR	--	--	--	--	--	--	DAC	IDAC	TAC	($/ton)
1PH	Hogged Fuel Boiler	$330,501	$579,996	$1,308,522	$102,785	$19,628	$67,290	$25,165	$754	$1,987	$83.46	$114,907	$103,374	$218,281	$12,265

NOTES:

(a) Uncontrolled hourly NO_x emissions estimate (lb/hr) = (uncontrolled annual NO_x emissions estimate [tons/yr]) x (2,000 lb/ton) / (annual hours of operation [hrs/yr])

Annual hours of operation (hrs/yr) = 8,760 (2)

(b) Uncontrolled NO_x emissions in flue gas (lb/MMBtu) = (uncontrolled hourly NO_x emissions estimate [lb/hr]) / (heat input capacity [MMBtu/hr])

(c) Hourly pollutant removed by control device (lb/hr) = (uncontrolled hourly NO_x emissions estimate [lb/hr]) x (control efficiency [%] / 100)

Control efficiency (%) = 25.0 (4)

(d) Annual pollutant removed by control device (tons/yr) = (uncontrolled annual NO_x emissions estimate [tons/yr]) x (control efficiency [%] / 100)

Control efficiency (%) = 25.0 (4)

(e) Normalized stoichiometric ratio = ((2) x (uncontrolled NOX emissions in flue gas (lb/MMBtu)] + (0.7)) x (control efficiency [%] / 100) / (uncontrolled NOX emissions in flue gas [lb/MMBtu]); see reference (5).

Control efficiency (%) = 25.0 (4)

(f) Reagent mass consumption (lb/hr) = (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (heat input capacity [MMBtu/hr]) x (normalized stoichiometric ratio) x (60.06 lb-urea/lb-mole) / (46.01 lb-NO_2/lb-mole) / (theoretical stoichiometric ratio]); see reference (6).

Theoretical stoichiometric ratio = 2 (7)

(g) Reagent solution flowrate (gal/hr) = (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (aqueous reagent solution density [lb/ft³]) x (7.4805 gal/ft³); see reference (8).

Aqueous reagent solution concentration (%) = 50.0 (8)

Aqueous reagent solution density (lb/ft³) = 71.0 (5)

(h) Power demand (kW) = (0.47) x (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (normalized stoichiometric ratio) x (heat input capacity [MMBtu/hr]) / (net plant heat rate [MMBtu/MWh]) + (power required to heat tank [kW]); see reference (9).

Net plant heat rate (MMBtu/MWh) = 10.0 (10)

Power required to heat tank (kW) = 35.0 (11)

(i) Water demand (gal/hr) = (f) x (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (density of water [lb/gal]); see reference (12).

Aqueous reagent solution concentration (%) = 50.0 (8)

Density of water (lb/gal) = 8.345

(j) Additional fuel usage (MMBtu/hr) = (f) x (heat of vaporization of water [Btu/lb]) x (reagent mass consumption [lb/hr]) x (MMBtu/1,000,000 Btu); see reference (13).

Heat of vaporization of water (Btu/lb) = 900 (13)

(k) Capital cost ($) = (capital cost [1999 $/MMBtu/hr]) x (heat input capacity [MMBtu/hr]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 1999)

Capital cost (1999 $/MMBtu/hr) = 1,700 (4)

Chemical engineering plant cost index for 2019 = 607.5 (14)

Chemical engineering plant cost index for 1999 = 390.6 (14)

(l) Balance of plant costs ($) = (213,000) x ((heat input capacity (MMBtu/hr)] / (net plant heat rate (MMBtu/MWh)])^(0.33) x (hourly pollutant removed by control device [lb/hr])^(0.12) x (retrofit factor); see reference (15).

Net plant heat rate (MMBtu/MWh) = 10.0 (10)

Retrofit factor = 1.00 (15)

(m) Total capital investment ($) = (1.3) x ((capital cost ($)] + (balance of plant cost ($)] + (reagent storage tank cost [$]) + (reagent storage tank construction [$]); see reference (16).

Reagent storage tank ($) = 74,875 (17)

Reagent storage area construction ($) = 50,000 (18)

(n) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (19).

Control device capital recovery factor = 0.0786 (o)

(o) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^[economic life (yrs)]) / ((1 + (interest rate [%] / 100)]^[economic life (yrs)] - 1); see reference (20).

Interest rate (%) = 4.75 (21)

SNCR economic life (yr) = 20 (22)

(p) Annual maintenance cost ($) = (0.015) x (total capital investment [$]); see reference (23).

(q) Annual reagent usage cost ($) = (reagent solution flowrate [gal/hr]) x (reagent cost [$/50% urea solution]) x (annual hours of operation [hrs/yr])

Reagent rate ($/50% urea solution) = 1.86 (r)

Annual hours of operation (hrs/yr) = 8,760 (2)

(r) Reagent rate ($/50% urea solution) = (reagent cost [2016 $/50% urea solution]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 2016)

Reagent rate (2016 $/50% urea solution) = 1.66 (4)

Chemical engineering plant cost index for 2019 = 607.5 (14)

Chemical engineering plant cost index for 2016 = 541.7 (14)

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

Electricity rate ($/kWh) = 0.079 (2)

Annual hours of operation (hrs/yr) = 8,760 (2)

(t) Annual water usage cost ($) = (water demand [gal/hr]) x (Mgal/1,000 gal) x (water rate [$/Mgal]) x (annual hours of operation [hrs/yr])

Water rate ($/Mgal) = 4.58 (2)

Annual hours of operation (hrs/yr) = 8,760 (2)

(u) Annual fuel additive cost ($) = (additional fuel usage [MMBtu/hr]) x (annual hours of operation [hrs/yr]) x (wood fuel rate [$/BDT) / (high heat value of wood [MMBtu/BDT]); see reference (24).

High heat value of wood (MMBtu/BDT) = 17.48 (25)

Wood fuel rate ($/BDT) = 25.0 (2)

Annual hours of operation (hrs/yr) = 8,760 (2)

(v) Ash disposal ($) = (additional fuel usage [MMBtu/hr]) x (ash weight percent [%] / 100) x (annual hours of operation [hrs/yr]) / (high heat value of wood [MMBtu/BDT]) x (landfill disposal rate [$/ton]); see reference (26).

Ash weight percent (%) = 1.75 (27)

Annual hours of operation (hrs/yr) = 8,760 (2)

High heat value of wood (MMBtu/BDT) = 17.48 (25)

Landfill disposal rate ($/ton) = 60.0 (2)

(w) Total indirect annual cost ($) = (0.03) x (annual maintenance cost [$]) + (capital recovery cost [$]); see reference (29).

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

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

REFERENCES:

(1) See Table 2-4. Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 3-1. Utility and Labor Rates.
(3) See Table 2-2. NO_x Evaluation for Regional Haze Four Factor Analysis.
(4) USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR) issued July 15, 2003. Assumes the average PM control efficiency and average capital cost.
(5) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.17.
(6) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.18.
(7) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. Assumes theoretical stoichiometric ratio for urea.
(8) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.19 and 1.20.
(9) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.42.
(10) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.3.1.
(11) Information provided by Chromalox vendor. Assumes heating of urea is required to a minimum of 95°F.
(12) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.45.
(13) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.48.
(14) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices.
(15) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.37. Assumes retrofit factor.
(16) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.35.
(17) Cost representative of 12,500 gallon double-wall, heated, storage tank provided by National Tank Outlet and Chromalox. Cost includes freight charges, but excludes sales tax.
(18) Assumes engineering estimate cost of construction for a covered storage tank (e.g., including engineering design services, concrete/foundation/secondary containment area work, and structure construction).
(19) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(20) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(21) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(22) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.4.2.
(23) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.39.
(24) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.49.
(25) 40 CFR, Subchapter C, Part 98, Subpart C. See Table C-1 "Default CO2 Emission Factors and High Heat Values of Various Types of Fuel". Factor for wood and wood residuals.
(26) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.50 and 1.51.
(27) Assumes typical average ash weight percent from the burning of hogged fuel.
(28) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.38.
(29) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.52 and 1.53.

REGIONAL HAZE FOUR-FACTOR ANALYSIS

WOODGRAIN MILLWORK, INC.

Prepared for

WOODGRAIN MILLWORK, INC.

LA GRANDE, OREGON

June 9, 2020

Project No. 1863.02.01

MAUL FOSTER ALONGI

Prepared by

Maul Foster & Alongi, Inc.

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CONTENTS

ACRONYMS AND ABBREVIATIONS

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

1 INTRODUCTION

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

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

(1) The cost of control,

(2) The time required to achieve control,

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

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

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

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

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

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

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

1.1 Facility Description

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

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

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

1.2 Process Description

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

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

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

2 APPLICABLE EMISSION SOURCES

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

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

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

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

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

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

2.1 Sources of PM_{10} Emissions

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

2.1.1 Line 1 and 2 Boilers (B1 and B2)

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

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

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

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

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

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

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

2.1.2 Green Furnish Dryer (GFD/C46)

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

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

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

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

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

2.1.4 Transfer to Line 1 Storage (C4)

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

2.1.5 Line 1 Reject Bin (C23)

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

2.1.6 Green Furnish Dryer Sanderdust Feed Bin (C47)

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

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

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

2.1.8 Natural Gas in the Line 1 and 2 Dryers

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

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

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

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

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

2.2 Sources of NO_X Emissions

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

2.3 Sources of SO_2 Emissions

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

2.4 Emission Unit Exhaust Parameters

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

3 REGIONAL HAZE FOUR-FACTOR ANALYSIS METHODOLOGY

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

3.1 Step 1: Determine Emission Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

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

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

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

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

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

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

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

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

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

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

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

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

4 PM_{10} ANALYSIS

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

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

4.1.1 Baghouses

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

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

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

4.1.2 Wet Venturi Scrubbers

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

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

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

4.1.3 Electrostatic Precipitator

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

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

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

4.2 Step 2—Selection of Emissions

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

4.3 Step 3—Characterizing Cost of Compliance

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

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

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

4.4 Step 4—Characterizing Time Necessary for Compliance

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

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

4.5.1 Energy Impacts

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

4.5.2 Environmental Impacts

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

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

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

4.6 Step 6—Characterize the Remaining Useful Life

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

5 NO_X ANALYSIS

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

5.1 Step 1—Determine NO_X Control Measures for Consideration

5.1.1 Selective Non-catalytic Reduction

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

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

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

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

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

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

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

5.1.2 Selective Catalytic Reduction and Hybrid Systems

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

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

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

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

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

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

5.1.3 Low NOx Burner

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

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

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

5.2 Step 2—Selection of Emissions

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

5.3 Step 3—Characterizing Cost of Compliance

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

5.4 Step 4—Characterizing Time Necessary for Compliance

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

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

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

5.6 Step 6—Characterize the Remaining Useful Life

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

6 SO_2 ANALYSIS

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

6.1 Step 1—Determine SO_2 Control Measures for Consideration

6.1.1 Dry Sorbent Injection

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

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

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

Dry sorbent injection systems introduce PM emissions into the exhaust stream, as mentioned above. This will cause increases to the particulate inlet loading of downstream particulate control devices. For retrofit applications, it is likely that modification of the downstream existing particulate control device will be necessary in order to accommodate the increased particulate inlet loading. It is anticipated that this increased loading cannot be accommodated solely through modifications to the existing control device. Assuming that this is the case, additional particulate controls will be required, resulting in cost increases and further energy and environmental impacts.

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

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

6.2 Step 2—Selection of Emissions

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

6.3 Step 3—Characterizing Cost of Compliance

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

6.4 Step 4—Characterizing Time Necessary for Compliance

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

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

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

6.6 Step 6—Characterize the Remaining Useful Life

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

7 CONCLUSION

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

LIMITATIONS

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

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

TABLES

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

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

REFERENCES:

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

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

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

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

REFERENCES:

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

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

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

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

REFERENCES:

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

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

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

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

NOTES:

acfm = actual cubic feet per minute.

BH = baghouse.

DESP = dry electrostatic precipitator.

dscfm = dry standard cubic feet per minute.

GFD = green furnish dryer.

RCO = regenerative catalytic oxidizer.

RTO = regenerative thermal oxidizer.

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

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

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

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

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

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

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

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

References:

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

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

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

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

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

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

(7) Information provided Woodgrain Millwork, Inc.

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

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

(10) Assumes continuous annual operation.

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

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

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

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

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

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

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

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

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

NOTES:

Mgal = thousand gallons.

MMBtu = million British thermal units.

Mscf = thousand standard cubic feet.

MWh = megawatt-hour.

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

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

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

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

REFERENCES:

(1) Assumes continuous annual operation.

(2) Information provided by Woodgrain Millwork, Inc.

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

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

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

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

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

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

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

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

See notes and formulas on following page.

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

NOTES:

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

Baghouse control efficiency (%) =	99.0	(3)

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

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

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

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

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

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

Control device capital recovery factor =	0.0786	(g)

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

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

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

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

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

Filter bag capital recovery factor =	0.2804	(g)

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

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

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

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

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

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

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

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

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

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

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

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

REFERENCES:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

See notes and formulas on following page.

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

NOTES:

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

Control efficiency (%) =	99.0	(3)

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

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

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

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

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

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

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

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

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

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

Control device capital recovery factor =	0.0786	(i)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REFERENCES:

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

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

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

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

See notes and formulas on following page.

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

NOTES:

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

Control efficiency (%) =	99.0	(3)

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

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

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

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

(d) Water demand (gal/yr) = (control efficiency [%] / 100) x (inlet grain loading [gr/ft³]) x (lb/7,000 gr) x (exhaust flowrate [scfm]) x (60 min/hr) x (annual hours of operation [hrs/yr]) / (mass fraction of solids in recirculation water) / (density of water [lb/gal]); see reference (6).

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

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

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

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

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

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

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

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

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

Control device capital recovery factor =	0.0947	(k)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REFERENCES:

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

Appendix G National Park Service Facility-specific Comment Summary Documents

(From Don Shepherd)

ARD comments on the
Northwest Pulp & Paper Association
REGIONAL HAZE RULE FOUR-FACTORANALYSIS FOR FOUR OREGON PULP AND PAPER MILLS
June 2020 Report

All4 prepared a report for the Northwest Pulp & Paper Association (NWPPA) and concluded that no additional controls were cost-effective for any pollutant at any of the mills it evaluated. We have several concerns with this report as it pertains to NO_X controls and have noted our concerns in the following excerpts from the All4 report.

NO_X Economic Impacts

LNB and FGR for Boiler NO_X Control

The capital cost of implementing LNB and FGR to reduce NO_X from each gas-fired industrial boiler without LNB is based on the document titled "Emission Control Study – Technology Cost Estimates" by BE&K Engineering for the American Forest and Paper Association (AF&PA), September 2001. Section 4.4 presents the costs associated with installing LNB, FGR, and a new fan on a 120,000 pounds of steam per hour (approximately 150 million British thermal units per hour [MMBtu/hr] heat input) natural gas-fired boiler. The direct capital cost (equipment and installation) was scaled from 2001 dollars to 2019 dollars using the CEPCI. The base capital cost was also scaled to each mill's boiler using an engineering cost scaling factor of 0.6 and the ratio of each mill's boiler heat input to the boiler heat input evaluated in the BE&K report. Table 2-4 summarizes the capital cost, annual cost, and cost effectiveness of implementing this control technology for the industrial boilers that do not already have LNB.

The effectiveness of installing LNB and FGR on each boiler is unknown and will depend on the current NO_X emission rate. Where current NOx concentration data was not available, a 64% NO_X reduction was assumed based on a comparison of AP-42 natural gas boiler pre-NSPS uncontrolled and LNB/FGR emission factors. Where current NO_X concentration data were available and higher than 50 ppm, a control efficiency was calculated based on a reduction to 50 ppm.

SNCR for Boiler NO_X Control

The cost of installing and operating an SNCR system on the natural gas-fired boilers was estimated using U.S. EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Non-Catalytic Reduction (SNCR)" (June 2019) that reflects calculation methodologies presented in the U.S. EPA's Air Pollution Control Cost Manual, Section 4, Chapter 1. The spreadsheet estimates capital and annualized costs of installing and operating an SNCR based on site-specific data entered, such as boiler design and operating data. As the cost algorithms were developed based on project costs for large coal-fired utility boilers, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers where this technology is routinely installed may not scale to smaller, variable load industrial boilers. The equipment cost was scaled to 2019 dollars using the CEPCI.

The U.S. EPA's cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied to account for the need to add multiple levels of injectors and perform additional tuning of the system across loads. The OAQPS Cost Manual (Section 4, Chapter 1) indicates that difficult installation conditions are often encountered for small boilers, and the boilers evaluated in this report are much smaller than coal-fired utility boilers.

SNCR control efficiencies vary widely, but urea-based systems typically achieve reductions from 37 to 60 percent on industrial boilers, according to the OAQPS Control Cost Manual. However, operating constraints on temperature, load, reaction time, and mixing often lead to less effective results when using SNCR in practice. Our analyses assume that SNCR would achieve 45% control on the boilers because pulp and paper mill boilers are subject to regular load swings. This control efficiency is supported by the range provided in the OAQPS Cost Manual and information publicly available from vendors. A formal engineering analysis would be required to ultimately determine if SNCR would be effective on the boilers. This type of analysis would include obtaining temperature and flow data, developing a model of each boiler using computational fluid dynamics, determining residence time and degree of mixing, determining placement of injectors, and testing.

SCR for Boiler NO_X Control

The cost of installing and operating SCR system on each of the boilers was estimated using U.S. EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR)" (June 2019) that reflects calculation methodologies presented in the U.S. EPA's Air Pollution Control Cost Manual, Section 4, Chapter 2. The spreadsheet estimates capital and annualized costs of installing and operating an SCR system based on site specific data entered, such as boiler design and operating data. As the cost algorithms were developed based on project costs for large coal-fired utility boilers, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers where this technology is routinely installed may not scale to smaller, variable load industrial boilers.

The U.S. EPA's cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied since the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, installation of a small duct burner to reheat the exhaust gas to the required temperature range, and the likelihood of needing a new ID fan to account for increased pressure drop. The equipment cost was scaled to 2019 dollars using the CEPCI. We assumed the SCR would achieve 90% control with installation of a duct burner to reheat the stack gas to 650 °F.

NPS Air Resources Division (ARD) Comments

Technical Feasibility of SCR on Wood-fired Boilers

The excerpt below is from the New Hampshire draft Regional Haze SIP:

> **Burgess BioPower**: The biomass unit at this facility was subject to NNSR for NOx at the time of their initial permitting; hence, the NOx limit was established as the LAER[1] based

[1] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NOx. While two recent determinations for similar facilities in

> limit. The NOx limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NOx/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for SO_2 at the time of its initial permitting in 2010; hence, the SO_2 limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. SO_2/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the SO_2 BACT. Sorbent injection was installed for acid gas control but is not used to control SO_2 emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs SO_2/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the emission limit for SO_2. For this reason, NHDES has determined that the current limits for the above facilities represent the "most effective use of control technologies" for NOx and SO_2. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

Retrofit Factor

All4 assumed a retrofit factor of 1.5 for every paper mill boiler it evaluated in Oregon, with this rationale:

> The U.S. EPA's cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied since the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, installation of a small duct burner to reheat the exhaust gas to the required temperature range, and the likelihood of needing a new ID fan to account for increased pressure drop. The equipment cost was scaled to 2019 dollars using the CEPCI. We assumed the SCR would achieve 90% control with installation of a duct burner to reheat the stack gas to 650 °F.

When a retrofit factor greater than 1.0 is entered into the "Data Inputs" spreadsheet in EPA Control Cost Manual (CCM) workbooks, this notice appears: "* NOTE: You must document why a retrofit factor of (>1.0) is appropriate for the proposed project." The EPA Control Cost Manual (CCM) addresses "Retrofit Cost Considerations" in section 2.6.4.2 and recommends that site-specific retrofit factors (greater than the 1.0 default value) should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book <u>Estimating Costs of Air Pollution Control</u> be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. In the absence of such a proper analysis, assume a retrofit factor = 1.0, which represents a 30% increase above costs for a "greenfield" project. The All4 blanket application of the maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy.

Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

Interest Rate
All4 used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.

Operating Costs
All4 overestimated the operating costs of SCR (and SNCR) when it substituted values for “Total operating time for the SCR (t_{op})” and “Total NOx removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. We participated in the EPA work group that developed the CCM workbooks for NO_X (and SO_2) controls and can advise that it is not appropriate to alter values in the “Design Parameters” spreadsheet because these values should, instead, be generated from the “Data Inputs” spreadsheet and the algorithms that operate on them according to the methods and equations described in the CCM.

The “Total operating time for the SCR (t_{op})” parameter is not meant to be the actual operating time for the control device, which All4 entered directly into the “Design Parameters” spreadsheet. Instead, it represents a method to adjust capacity utilization to actual (or permitted) utilization based upon a fraction (Total System Capacity Factor (CF_{total})) applied to the maximum capacity. (The spreadsheet assumes that the boiler is operating at maximum capacity for the hours calculated by t_{op}.) All4 compounded its error by also overriding the calculation of Total NOx removed per year to reflect percent removed from the PSEL or actual conditions instead of percent removed from the emissions that would have resulted from All4’s hours of operation.

The basic parameters (on the “Data Inputs” spreadsheet) that define emissions and control costs are:

- maximum heat input rate (QB)
- higher heating value (HHV) of the fuel
- estimated actual annual fuel consumption
- net plant heat input rate (NPHR)
- Number of days the SCR (or SNCR) operates (t_{SCR} or t_{SNCR})
- Number of days the boiler operates (t_{plant})
- Inlet NOx Emissions (NO_{Xin}) to SCR (or SNCR)
- Outlet NOx Emissions (NO_{Xout}) from SCR (or SNCR)

All but “estimated actual annual fuel consumption” are essentially fixed by the boiler, fuel, and control device characteristics. The “Number of days the SCR operates (tSCR)” typically equals “Number of days the boiler operates (tplant).”[2] We adjusted “estimated actual annual fuel consumption” to yield the uncontrolled emissions specified by All4.

All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4’s fuel cost is higher than the current EIA estimate.)

All4 included property taxes in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

[2] In March 2021, EPA revised the SNCR workbook to include an entry for the “Number of days the boiler operates (tplant).” Until that revision, the SNCR workbook assumed 365 days of plant operation.

We are using the SCR and SNCR workbooks developed by EPA for its CCM to address the problems described above and will be sending them to OR DEQ soon. We will show that the costs of achieving significant NO_X reductions at Oregon's pulp & paper mills are significantly lower than submitted by the NWPPA.

Georgia-Pacific
Toledo LLC
July 30, 2021

Excerpts from the company submittal dated June 2020

Power Boilers
The Georgia-Pacific-Toledo (GPT) Mill is permitted to fire fuel oil in the No. 1 Power Boiler, but only fires natural gas, resulting in lower PM_{10} and SO_2 emissions. The Mill is permitted to fire hog fuel and old corrugated container (OCC) rejects in the No. 4 Power Boiler, but only fires natural gas, resulting in lower NO_X, PM_{10}, and SO_2 emissions.

PM_{10} Emissions
The four boilers at the GP Toledo Mill burn only natural gas and have minimal PM_{10} emissions. No PM_{10} controls beyond burning natural gas are feasible for these boilers.

NO_X Economic Impacts
The GP Toledo No. 5 Power Boiler already uses LNB and FGR to reduce NO_X emissions.

Lime Kiln
PM_{10} Emissions
GP Toledo utilizes wet scrubbers for PM control on its lime kilns.

SO_2 Emissions
The lime kilns provide inherent control of SO_2 through absorption of sulfur by the calcium in the kiln. The mill fires natural gas as the primary fuel in its lime kilns, which minimizes SO_2 emissions, particularly during startup and shutdown. The lime kilns are equipped with wet scrubbers, primarily for reduction of PM and TRS emissions. Actual lime kiln SO_2 emissions at the GP Toledo mill are less than 1 tpy, so no additional SO_2 controls are necessary for these kilns.

PAPER MACHINES AND PULP DRYERS
Paper machines and pulp dryers consist of the wet end and the dry end and the combined equipment can be the length of a football field and have many different exhaust points through roof vents or building exhausts. On the wet end, pulp is combined with additives and diluted with water at the head box, applied to the former or wire, where it forms a sheet as the water drains, and then travels to the press and dryer sections (dry end) to remove the remaining water. The paper machines at GP Toledo are steam heated and do not have emissions of NO_X or SO_2.

OR DEQ
In a letter dated January 21, 2021, DEQ notified Georgia Pacific of its preliminary determination that their Toledo facility would likely be required to install control devices on several of its emissions units, as shown in Table 3-46. Cost effectiveness of adding a baghouse to EU-118 may be revised after the results of upcoming source testing.

Table 0 1: Control devices likely required Georgia-Pacific, Toledo

Emissions Unit	**Control Device**	**Target Pollutant**
EU-118 Hardwood Chip handling	Baghouse	PM_{10}
EU-1 Lime Kiln	LNB	NO_x
EU-2 Lime Kilns	LNB	NO_x
EU-3 Lime Kiln	LNB	NO_x
EU-11 No. 4 Boiler	SCR	NO_x
EU-13 No. 1 Boiler	SCR	NO_x
EU-18 No. 3 Boiler	SNCR	NO_x

ARD Comments

GP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the Power Boiler and the Package Boiler. All4 overestimated capital costs when it assumed a retrofit factor of 1.5 without the justification and documentation required by the CCM and EPA policy.

All4 also overestimated the operating costs of SCR when it substituted values for “Total operating time for the SCR (t_{op})” and “Total NOx removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. For example, for the Power Boiler #3 (PSEL), All4’s workbook correctly calculated the Total System Capacity Factor = 0.984 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 8620 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 8620 hours. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 107.6 tpy) instead of 90% removed from the emissions (98.4 tpy) that would have resulted from All4’s 8760 hours of operation (90% * 98.4 tpy). Instead, we adjusted “estimated actual annual fuel consumption” to yield the uncontrolled emissions specified by All4.

All4’s resulting Total Annual Cost of $1.3 million for the Power Boiler #3 contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unjustified retrofit factor. (All4 also used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.) Operating costs were overestimated due to overriding of the “Total operating time” parameter. All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4’s fuel cost of $5.00/mmBtu exceeds the approximately $4.00/mmBtu Oregon industrial price for natural gas according to the EIA. [3]) Instead of All4’s estimated cost-effectiveness = $13,579/ton, we estimate a Total Annual Cost of $1.2 million = $12,446/ton for addition of SCR to remove 97 ton/yr of NO_X. (Even though there was no justification provided for the reheat fuel use rate, we accepted All4’s estimate to estimate reheat cost—please see the attached workbooks.) The cost effectiveness of adding SCR for Power Boiler #3 also exceeds the OR DEQ threshold under

[3] Oregon Natural Gas Industrial Price (Dollars per Thousand Cubic Feet) (eia.gov)

actual conditions, but that result is highly dependent upon the cost of reheating the SCR inlet gas stream and should be verified.

The same issues apply to Power Boiler #1 and the Hogged Fuel Boiler #4. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for Power Boiler #1 and the Hogged Fuel Boiler #4.

SCR	Company/Consultant Estimates		NPS Air Resources Division Estimates	
Unit	#3 Pwr Blr (PSEL)	#3 Pwr Blr (actuals)	#3 Pwr Blr (PSEL)	#3 Pwr Blr (actuals)
Emissions Reduction (tpy)	97	68	97	68
Total Annual Cost	$ 1,314,983	$ 1,296,647	$ 1,203,346	$ 916,698
Cost-Effectiveness ($/ton)	$ 13,579	$ 19,057	$ 12,446	$ 13,465

SCR	Company/Consultant Estimates		NPS ARD Estimates	
Unit	#1 Pwr Blr (PSEL)	#1 Pwr Blr (actuals)	#1 Pwr Blr (PSEL)	#1 Pwr Blr (actuals)
Emissions Reduction (tpy)	201	135	200	135
Total Annual Cost	$ 1,736,111	$ 1,713,128	$ 1,279,086	$ 949,489
Cost-Effectiveness ($/ton)	$ 8,623	$ 12,681	$ 6,386	$ 7,014

SCR	**Company/Consultant Estimates**		**NPS Air Resources Division Estimates**	
Unit	#4 Hog Fuel Blr (PSEL)	#4 Hog Fuel Blr (actuals)	#4 Hog Fuel Blr (PSEL)	#4 Hog Fuel Blr (actuals)
Emissions Reduction (tpy)	197	190	197	190
Retrofit factor	1.5	1.5	1	1
Total Annual Cost	$ 2,175,317	$ 2,307,306	$ 1,429,189	$ 1,023,762
Cost-Effectiveness ($/ton)	$ 11,067	$ 12,173	$ 7,262	$ 5,374

Power Boiler #3 SNCR

Because OR DEQ proposed that SNCR be applied to Power Boiler #3 instead of SCR, we evaluated both the PSEL and actual emissions scenarios for this boiler. All4 overestimated costs for the following reasons:

- A retrofit factor of 1.5 was applied with no justification.
- The interest rate was too high (4.75% versus 3.25%).
- The $5.00/mmBtu fuel cost was not justified (versus the approximately $4.00/mmBtu current industrial cost of natural gas in Oregon according to the EIA).
- All actual operating costs were overestimated because All4 overrode/overestimated the "Total operating time for the SNCR" parameter (8531 hrs versus 5902 hrs).

Our corrected estimates are shown below.

SNCR	Company/Consultant Estimates		NPS Air Resources Division Estimates	
Unit	#3 Pwr Blr (PSEL)	#3 Pwr Blr (actuals)	#3 Pwr Blr (PSEL)	#3 Pwr Blr (actuals)
Emissions Reduction (tpy)	48	34	48	34
Total Annual Cost	$ 414,919	$ 412,543	$ 307,576	$ 259,637
Cost-Effectiveness ($/ton)	$ 8,569	$ 12,126	$ 6,362	$ 7,607

Results & Conclusions

- Addition of SCR to Power Boilers #1 and Hogged Fuel Boiler #4 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL operating conditions.
- Addition of SCR to Power Boiler #1 and Hogged Fuel Boiler #4 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under actual operating conditions.
- Addition of SCR to Power Boiler #3 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness relative to the OR DEQ threshold under PSEL and actual operating conditions is highly dependent upon costs to reheat the SCR inlet gas stream; this should be investigated further.
- Addition of SCR to these three boilers could reduce NO_X emissions by 494 tons/yr under PSEL conditions or 393 tons/yr under actual conditions.
- Addition of SNCR to Power Boiler #3 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL or actual operating conditions.

Georgia Pacific
Wauna Mill
July 1, 2021

Excerpts from the company submittal dated June 2020

Power Boilers

SO2 Emissions
The GP Wauna Fluidized Bed Boiler already has limestone addition to the fluidized bed. No further SO2 emissions controls are feasible for the GP boilers that burn only natural gas.

PM10 Emissions
The Power Boiler at the GP Wauna Mill burns only natural gas and has minimal PM_{10} emissions. No PM_{10} controls beyond burning natural gas are feasible for this boiler. The GP Wauna Mill's biomass-fired Fluidized Bed Boiler is controlled by a fabric filter, is subject to a filterable PM emission limit of 0.01 grain per dry standard cubic foot (gr/dscf), and complies with both New Source Performance Standards (NSPS, Subpart Db) and Boiler MACT. Based on a review of similar units in the RBLC, this unit is already well controlled for PM_{10}.

PM_{10} Economic Impacts
For purposes of this report, and because the PM_{10} PSEL for the GP Wauna Fluidized Bed Boiler is 62.4 tpy, a cursory evaluation of whether adding a polishing WESP to that unit to reduce PM_{10} emissions further would be cost effective was performed. Based on U.S. EPA's fact sheet for WESPs, in 2002 dollars, the capital cost ranges from $40 to $200 per standard cubic foot per minute (scfm) exhaust flow rate and the annual cost ranges from $12 to $46 per scfm. Based on the low end of these ranges and a flow rate of 55,000 scfm, a polishing WESP would require an investment of at least $2.2 million in capital cost and $660,000 per year in annual cost. While achieving an additional 99% reduction of PM_{10} emissions from the outlet stream of an already well controlled source utilizing a baghouse is highly unlikely, even if a polishing WESP achieved a 99 percent reduction in the 62.4-tpy PM_{10} PSEL, the approximate cost would be $10,684/ton of PM10 removed, which is not cost effective.

SO_2 Economic Impacts
The capital cost for a system to inject milled trona prior to the fabric filter on the GP Wauna Fluidized Bed Boiler was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract. Industry standard labor, chemical, and utility costs were used to estimate the annual cost of operating the system. The Sargent and Lundy report indicates that 90% SO2 control can be achieved when injecting trona prior to a fabric filter.

Recovery Furnace
The Georgia Pacific (GP) Wauna Mill is permitted to fire fuel oil in the recovery furnace, but only fires natural gas as auxiliary fuel, resulting in lower PM_{10} and SO_2 emissions.

Lime Kiln

The Georgia Pacific (GP) Wauna Mill is permitted to fire fuel oil in the lime kiln, but only fires natural gas as auxiliary fuel, resulting in lower PM_{10} and SO_2 emissions.

PM10 Emissions

GP Wauna utilizes wet scrubbers for PM control on its lime kiln. An ESP prior to the wet scrubber would provide additional PM_{10} control and is considered technically feasible.

SO_2 Emissions

The lime kiln provides inherent control of SO_2 through absorption of sulfur by the calcium in the kiln. The mill fires natural gas as the primary fuel in its lime kiln, which minimizes SO_2 emissions, particularly during startup and shutdown. The portion of the SO_2 PSEL assigned to the lime kiln at GP Wauna is less than 5 tpy, so no additional SO_2 controls are necessary for this kiln.

Towel & Tissue Machines

GP Wauna's towel and tissue machines include fuel burning sources and wet controls to limit PM_{10} emissions. Tissue machines are configured differently than traditional paper machines and pulp dryers and their PM emissions are higher in most cases. GP Wauna has performed an evaluation of whether additional controls are feasible and is submitting the evaluation as an attachment to their cover letter transmitting this report.

OR DEQ

In a letter dated January 21, 2021, DEQ notified Georgia Pacific of its preliminary determination that their Wauna facility would likely be required to install control devices on several of its emissions units, as shown in Table 3-44, including Low NO_x Burners and SCR. Discussions with the facility are ongoing.

Table 0 2: Control devices likely required Georgia Pacific – Wauna Mill.

Emissions Unit	Control Device	Target Pollutant
Paper Machine 1: Yankee Burner	LNB	NO_x
Paper Machine 2: Yankee Burner	LNB	NO_x
Paper Machine 5: Yankee Burner	LNB	NO_x
21 - Lime Kiln	LNB	NO_x
Paper Machine 6: TAD1 Burners	LNB	NO_x
Paper Machine 7: TAD1 Burners	LNB	NO_x
Paper Machine 6: TAD2 Burners	LNB	NO_x
Paper Machine 7: TAD2 Burners	LNB	NO_x
33 - Power Boiler	SCR	NO_x

ARD Comments

GP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the Power Boiler and the Fluidized Bed Boiler. All4 overestimated capital costs when it assumed a retrofit factor of 1.5 without the justification and documentation required by the CCM and EPA policy.

All4 also overestimated the operating costs of SCR when it substituted values for “Total operating time for the SCR (t_{op})” and “Total NOx removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. For example, for the Fluidized Bed Boiler (PSEL), All4’s workbook correctly calculated the Total System Capacity Factor = 0.833 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 7297 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 7297 hours. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 224.4 tpy) instead of 90% removed from the emissions (242.3 tpy) that would have resulted from All4’s 8760 hours of operation (90% * 242.3 tpy). Instead, we adjusted “estimated actual annual fuel consumption” to yield the uncontrolled emissions specified by All4.

All4’s resulting Total Annual Cost of $3 million for the Fluidized Bed Boiler contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unjustified retrofit factor. (All4 also used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.) Operating costs were overestimated due to over-riding of the Total operating time parameter. All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4’s fuel cost is 25% higher than the current Oregon industrial natural gas price.[4]) Instead of All4’s estimated cost-effectiveness = $15,069/ton, we estimate a Total Annual Cost of $1.8 million = $8775/ton for addition of SCR to remove 202 ton/yr of NO_X. (Even though there was no justification provided for the reheat fuel use rate, we accepted All4’s estimate to estimate reheat cost—please see the attached workbooks.)

SCR	**Company/Consultant Estimates**		**NPS ARD Estimates**	
Unit	FBB (PSEL)	FBB (actual)	FBB (PSEL)	FBB (actual)
Emissions Reduction (tpy)	202	153	202	155
Total Annual Cost	$ 3,043,381	$ 3,222,435	$ 1,770,437	$ 1,327,408
Cost-Effectiveness ($/ton)	$ 15,069	$ 21,000	$ 8,775	$ 8,590

The same issues apply to Fluidized Bed Boiler at actual conditions as well as the Power Boiler at PSEL and actual conditions. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions and the cost-effectiveness of adding SCR falls below the OR DEQ threshold of $10,000/ton for the PSEL and actual cases for both boilers.

[4] Oregon Natural Gas Industrial Price (Dollars per Thousand Cubic Feet) (eia.gov)

SCR	**Company/Consultant Estimates**		**NPS ARD Estimates**	
Unit	Pwr Blr (PSEL)	Pwr Blr (actual)	Pwr Blr (PSEL)	Pwr Blr (actual)
Emissions Reduction (tpy)	532	239	530	240
Total Annual Cost	$ 4,444,671	$ 2,942,622	$ 2,088,644	$ 1,127,831
Cost-Effectiveness ($/ton)	$ 8,353	$ 12,317	$ 3,939	$ 4,709

Results & Conclusions

- Addition of SCR to the Power Boiler and the Fluidized Bed Boiler is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL or actual operating conditions.
- Addition of SCR to these two boilers could reduce NO_X emissions by 732 tons/yr under PSEL conditions or 395 tons/yr under actual conditions.

Boise Cascade Wood Products, LLC - Elgin Complex

OR DEQ: In a letter dated January 21, 2021, DEQ notified Boise Cascade Wood Products of its preliminary determination that their Elgin facility would likely be required to install Selective Catalytic Reduction on Boilers 1 and 2.

Excerpts from Boise Cascade/All4's June 2020 report, "REGIONAL HAZE RULE FOUR FACTOR ANALYSIS FOR THE BOISE CASCADE WOOD PRODUCTS ELGIN PLYWOOD MILL"

SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2010, the Elgin Mill has made emissions reductions for a variety of reasons. Each of the biomass boilers is subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule. Compliance with these standards required changes to operating practices, including use of clean fuels for startup.

FOUR FACTOR ANALYSIS FOR BOILERS

This section of the report presents the results of a Four Factor analysis for PM_{10}, SO_2, and NO_X emitted from the Elgin Mill biomass boilers. The two boilers are each 72 MMBtu/hr biomass wet stoker units and are controlled by a common dry electrostatic precipitator (ESP).

Site Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

Selective Catalytic Reduction (SCR)

Although SCR was not identified in the RLBC search as a technology typically employed on biomass-fired industrial boilers, it has been applied to coal-fired utility boilers. The presence of alkali metals such as sodium and potassium, which are commonly found in wood, but not fossil fuels, will poison catalysts and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic. Therefore, it is not feasible to place an SCR upstream of a particulate control device on a biomass boiler.

PM10 Emissions

Due to the typically lower PM_{10} removal efficiencies than dry ESPs, and the generation of wastewater, this analysis does not consider the use of wet controls for PM_{10} emissions control. Fabric filters are rarely implemented on wood-fired boilers due to risk of fire (any retrofit implementation would require a long stretch of ductwork between the economizer and the control device to reduce the risk of fire). ESPs are almost as efficient as the best fabric filters without the fire risk. ESPs can withstand higher temperatures, have a smaller footprint, use less energy, and have lower maintenance requirements and better separation efficiencies than fabric filters. Therefore, use of a fabric filter for PM_{10} control was not considered feasible and was not evaluated. The Elgin Mill biomass boilers are already very well controlled and are subject to Boiler MACT emission limits and work practices.

NOx Emissions

NO_X emissions from biomass boilers originate primarily from oxidation of fuel bound nitrogen. The Elgin Boilers are in the biomass wet stoker subcategory under the Boiler MACT rule. Biomass is fed to the boilers above the grate, begins to combust in suspension, and then completes combustion on the grate. Low-NO_X burners and water injection are not applicable to this design. The air system is optimized during the required Boiler MACT tune-ups and FGR is not likely to provide a significant reduction in NO_X.

Add-on NOx controls such as SNCR and SCR require a specific temperature window to be effective. These controls were developed for and have predominantly been applied to fossil fuel fired boilers. There are challenges associated with applying SNCR to an industrial biomass boiler due to variability in boiler load. Good mixing of the reagent and NOx in the flue gas at the optimum temperature window is the key to achieving a NOx reduction for SCR and SNCR. In biomass boilers, this temperature window is a function of the variations in fuel quality and the load on the boiler. The temperature profile in a wood-fired industrial boiler is not as constant as that of a fossil fuel-fired utility boiler. Biomass boilers at forest products mills are often subject to highly variable swings in steaming rate, fuel flow, fuel mix, and bark moisture, depending on mill steam demand, availability of bark, amount of other fuels fired, and weather conditions.

The feasibility of SCR application to biomass boilers is also uncertain. This technology has been demonstrated mostly on large coal- and natural gas-fired combustion units in the utility industry.

In practice, SCR systems operate at NOx control efficiencies in the range of 70 to 90% for fossil fuel utility boilers. Optimum temperatures for the SCR process range from 480 to 800°F. Due to catalyst plugging and poisoning problems associated with locating the catalyst prior to the particulate control device , an SCR system would have to be installed after an existing particulate control device, and would likely require installation of a gas-fired flue gas re-heater to achieve the optimum reaction temperature (the flue gas temperature for biomass boilers is typically less than 480°F). This would incur associated fuel costs and pollution increases, running counter to the administration's goal to reduce greenhouse gases, assuming there is adequate space to install the size re-heater needed to raise the temperature of the exhaust gas stream to the optimum temperature of 600 °F. Despite these challenges, for purposes of this analysis, we evaluated cost effectiveness of an SCR achieving 90% control, but we incorporated a retrofit factor of 1.5 to account for the difficulty of applying SCR to a biomass boiler and the likely need to add ductwork and to replace the fan to overcome additional pressure drop through the system.

Site Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

NO_X Economic Impacts
This section describes the economic impacts associated with each NOx add-on control option evaluated for the boilers. Note that cost effectiveness was evaluated based on the PSEL, and the cost per ton would be even higher if evaluated based on actual emissions.

SCR for Boiler NO_X Control
All4 applied a retrofit factor of 1.5 because the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, the need for stack reheat, and the likelihood of needing a new induced draft fan to account for increased pressure drop.

The All4 cost analysis is based on the boilers' capacity and their NO_X PSEL of 170 tpy, although actual emissions in 2017 were only 125.6 tpy. Installing an SCR is not considered cost effective because the capital cost is estimated at more than $15 million and the cost effectiveness values are well in excess of $3,400/ton of pollutant removed, the cost effectiveness threshold for non-EGUs used by EPA for similar studies.

REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES
All4 assumed that the emissions units and controls included in this analysis have a remaining useful life of twenty years or more.

NPS Air Resources Division (ARD) Analysis

Technical Feasibility of SCR on Wood-fired Boilers
The excerpt below is from the New Hampshire draft Regional Haze SIP:

> **Burgess BioPower**: The biomass unit at this facility was subject to NNSR for NOx at the time of their initial permitting; hence, the NOx limit was established as the LAER[5] based limit. The NOx limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NOx/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for SO_2 at the time of its initial permitting in 2010; hence, the SO_2 limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. SO_2/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the SO_2 BACT. Sorbent injection was installed for acid gas control but is not used to control SO_2 emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs SO_2/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the

[5] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NOx. While two recent determinations for similar facilities in Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

> emission limit for SO_2. For this reason, NHDES has determined that the current limits for the above facilities represent the “most effective use of control technologies” for NOx and SO_2. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

We have several concerns with the Boise Cascade analyses conducted by All4.

Retrofit Factor
All4 assumed a retrofit factor of 1.5 for every woodwaste boiler it evaluated in Oregon. The EPA Control Cost Manual (CCM) recommends that site-specific retrofit factors (greater than the 1.0 default value) should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book Estimating Costs of Air Pollution Control be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The CCM also addresses “Retrofit Cost Considerations” in section 2.6.4.2. In the absence of such a proper analysis, assume a retrofit factor = 1.0, which represents a 30% increase above costs for a “greenfield” project. The All4 blanket application of the maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy.

SCR Equipment Life
All4 assumed a 20-year life for these boilers; for all other woodwaste-fired boilers All4 evaluated in Oregon and Washington, All4 assumed 25-year life; we used the CCM default = 25 years.

Chemical Engineering Plant Cost Index (CEPCI)
All4 used a 2019 CEPCI = 603.1; the correct CEPCI = 607.5.

Interest Rate
All4 used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.

Operating Costs
All4 overestimated the operating costs of SCR (and SNCR) when it substituted values for “Total operating time for the SCR (t_{op})” and “Total NOx removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. We participated in the EPA work group that developed the CCM workbooks for NO_X (and SO_2) controls and can advise that it is not appropriate to alter values in the “Design Parameters” spreadsheet because these values should, instead, be generated from the “Data Inputs” spreadsheet and the algorithms that operate on them according to the methods and equations described in the CCM.

The “Total operating time for the SCR (t_{op})” parameter is not meant to be the actual operating time for the control device, which All4 entered directly into the “Design Parameters” spreadsheet. Instead, it represents a method to adjust capacity utilization to actual (or permitted) utilization based upon a fraction (Total System Capacity Factor (CF_{total})) applied to the maximum capacity. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect percent removed from the PSEL or actual conditions instead of percent removed from the emissions that would have resulted from All4's hours of operation.

The basic parameters (on the "Data Inputs" spreadsheet) that define emissions and control costs are:

- maximum heat input rate (QB)
- higher heating value (HHV) of the fuel
- estimated actual annual fuel consumption
- net plant heat input rate (NPHR)
- Number of days the SCR (or SNCR) operates (t_{SCR} or t_{SNCR})
- Number of days the boiler operates (t_{plant})
- Inlet NOx Emissions (NO_{Xin}) to SCR (or SNCR)
- Outlet NOx Emissions (NO_{Xout}) from SCR (or SNCR)

All but "estimated actual annual fuel consumption" are essentially fixed by the boiler, fuel, and control device characteristics. The "Number of days the SCR operates (tSCR)" typically equals "Number of days the boiler operates (tplant)."[6] We adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

For example, the "Total operating time for the SCR (t_{op})" parameter is not meant to be the actual operating time for the control device. Instead, it represents a method to adjust capacity utilization to actual utilization based upon a fraction (Total System Capacity Factor (CF_{total}) applied to the maximum capacity. For the Power Boiler (PSEL), All4's workbook correctly calculated the Total System Capacity Factor = 0.976 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 8550 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 8550 hours. All4 compounded its error by also overriding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 170 tpy) instead of 90% removed from the emissions (153 tpy) that would have resulted from All4's 8760 hours of operation (90% * 153 tpy).

All4 included property taxes in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

We applied the CCM workbook and adjusted the "estimated actual annual fuel consumption" to yield the uncontrolled emissions (170 ton/yr) specified by All4. Our results are shown below.

[6] In March 2021, EPA revised the SNCR workbook to include an entry for the "Number of days the boiler operates (tplant)." Until that revision, the SNCR workbook assumed 365 days of plant operation.

Operating company Boise Cascade
Facility Elgin

SCR	Company/Consultant Estimates	NPS ARD Estimates
Unit	PB #1 & #2	PB #1 & #2
Total Annual Cost	$ 1,450,706	$ 844,824
Emissions Reduction (tpy)	152	153
Cost-Effectiveness ($/ton)	$ 9,538	$ 5,533

Results & Conclusions
Addition of SCR to Power Boilers #1 & #2 would reduce NO_X emissions by 153 ton/yr and be much less expensive than estimated by All4 and its cost-effectiveness is well below the Oregon threshold.

Boise Cascade Wood Products, LLC – Medford

OR DEQ: In a letter dated January 21, 2021, DEQ notified Boise Cascade Wood Products of its preliminary determination that their Medford facility would likely be required to install SCR on Boilers 1, 2 and 3. Discussions with the facility are ongoing.

Excerpts from Boise Cascade/All4's June 2020 report, "REGIONAL HAZE RULE FOUR FACTOR ANALYSIS FOR THE BOISE CASCADE WOOD PRODUCTS MEDFORD PLYWOOD MILL"

SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2011, the Medford Mill has made improvements to reduce its emissions. The biomass boilers are subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Compliance with these standards required changes to operating practices, including use of clean fuels for startup. Beginning in 2012, combustion efficiency improvements were made on Boilers 2 and 3 so that the Boiler MACT CO limits could be met. These improvements reduced CO emissions but did not increase NOx emissions. Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule.

FOUR FACTOR ANALYSIS FOR BOILERS

The three boilers are biomass hybrid suspension grate units, are controlled by a dry electrostatic precipitator (ESP), and produce 50,000, 70,000, and 100,000 pounds of steam per hour at capacity, respectively. The Medford Mill typically operates two of the boilers at a time.

Site Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

Selective Catalytic Reduction (SCR)

Although SCR was not identified in the RLBC search as a technology typically employed on biomass-fired industrial boilers, it has been applied to coal-fired utility boilers. The presence of alkali metals such as sodium and potassium, which are commonly found in wood, but not fossil fuels, will poison catalysts and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic. Therefore, it is not feasible to place an SCR upstream of a particulate control device on a biomass boiler.

PM_{10} Emissions

Due to the typically lower PM_{10} removal efficiencies than dry ESPs, and the generation of wastewater, this analysis does not consider the use of wet controls for PM_{10} emissions control. Fabric filters are rarely implemented on wood-fired boilers due to risk of fire (any retrofit implementation would require a long stretch of ductwork between the economizer and the control device to reduce the risk of fire). ESPs are almost as efficient as the best fabric filters without the fire risk. ESPs can withstand higher temperatures, have a smaller footprint, use less energy, and have lower maintenance requirements and better separation efficiencies than fabric filters. Therefore, use of a fabric filter for PM_{10} control was not considered feasible and was not evaluated. The Elgin Mill biomass boilers are already very well controlled and are subject to Boiler MACT emission limits and work practices.

The Medford Mill biomass boilers are already very well controlled and are subject to a stringent PM emission limit based on a LAER analysis, as well as Boiler MACT emission limits and work practices. Because the August 20, 2019 EPA Regional Haze Guidance mentions that states can exclude sources that have been through LAER review from further analysis, we have not evaluated further PM10 controls on the biomass boilers.

$S0_2$ Emissions

The Medford Mill biomass boiler emits very little SO_2 because biomass is an inherently low-sulfur fuel.

NOx Emissions

NOx emissions from biomass boilers originate primarily from oxidation of fuel bound nitrogen. The Medford Boilers are in the biomass hybrid suspension grate subcategory under the Boiler MACT rule. Biomass is fed to the boilers via air-swept spouts, begins to combust in suspension, and then completes combustion on a grate. Low-NOx burners and water injection are not applicable to this design. The air system is optimized during required Boiler MACT tune-ups and FGR is not likely to provide a significant reduction in NOx.

Add-on NOx controls such as SNCR and SCR require a specific temperature window to be effective. These controls were developed for and have predominantly been applied to fossil fuel fired boilers. There are challenges associated with applying SNCR to an industrial biomass boiler due to variability in boiler load. Good mixing of the reagent and NOx in the flue gas at the optimum temperature window is the key to achieving a NOx reduction for SCR and SNCR. In biomass boilers, this temperature window is a function of the variations in fuel quality and the load on the boiler. The temperature profile in a wood-fired industrial boiler is not as constant as that of a fossil fuel-fired utility boiler. Biomass boilers at forest products mills are often subject to highly variable swings in steaming rate, fuel flow, fuel mix, and bark moisture, depending on mill steam demand, availability of bark, amount of other fuels fired, and weather conditions.

The feasibility of SCR application to biomass boilers is also uncertain. SCR uses a catalyst to reduce NOx to nitrogen, water, and oxygen. SCR technology employs aqueous or anhydrous ammonia as a reducing agent that is injected into the gas stream near the economizer and upstream of the catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. An ammonium salt intermediate is formed at the catalyst surface and subsequently decomposes to elemental nitrogen and water. This technology has been demonstrated mostly on large coal- and natural gas-fired combustion units in the utility industry.

In practice, SCR systems operate at NOx control efficiencies in the range of 70 to 90% for fossil fuel utility boilers. Optimum temperatures for the SCR process range from 480 to 800°F. Due to catalyst plugging and poisoning problems associated with locating the catalyst prior to the particulate control device, an SCR system would have to be installed after an existing particulate control device, and would likely require installation of a gas-fired flue gas re-heater to achieve the optimum reaction temperature (the flue gas temperature for biomass boilers is typically less than 480°F). This would incur associated fuel costs and pollution increases, running counter to the administration's goal to reduce greenhouse gases, assuming there is adequate space to install the size re-heater needed to raise the temperature of the exhaust gas stream to the optimum temperature of 600 °F. Despite these challenges, for purposes of this analysis, we evaluated cost effectiveness of an SCR achieving 90% control, but we incorporated a retrofit factor of 1.5 to account for the difficulty of applying SCR to a biomass boiler and the likely need to add ductwork and to replace the fan to overcome additional pressure drop through the system.

Site Specific Factors Limiting Implementation
Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

NOx Economic Impacts
This section describes the economic impacts associated with each NOx add-on control option evaluated for the boilers. Note that cost effectiveness was evaluated based on the PSEL, and the cost per ton would be even higher if evaluated based on actual emissions.

SCR for Boiler NO_X Control
All4 applied a retrofit factor of 1.5 because the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, the need for stack reheat, and the likelihood of needing a new induced draft fan to account for increased pressure drop.

The All4 cost analysis is based on the boilers' capacity and their NOx PSEL of 210 tpy, although actual emissions in 2017 were only 105 tpy. Installing an SCR is not considered cost effective because the capital cost is estimated at more than $27 million and the cost effectiveness values are well in excess of $3,400/ton of pollutant removed, the cost effectiveness threshold for non-EGUs used by EPA for similar studies.

REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES
All4 assumed that the emissions units and controls included in this analysis have a remaining useful life of twenty years or more.

CONCLUSION
Based on the Four Factor analysis presented above, All4 concluded that no additional controls were determined to be cost effective for the biomass boilers at the Medford Mill.

NPS Air Resources Division (ARD) Analysis

Technical Feasibility of SCR on Wood-fired Boilers
The excerpt below if from the New Hampshire draft Regional Haze SIP:
Burgess BioPower: The biomass unit at this facility was subject to NNSR for NOx at the time of their initial permitting; hence, the NOx limit was established as the LAER[7] based limit. The NOx limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NOx/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for SO_2 at the time of its initial permitting in 2010; hence, the SO_2 limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. SO_2/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the SO_2 BACT. Sorbent injection was installed for acid gas control but is not used to control SO_2 emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs SO_2/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the emission limit for SO_2. For this reason, NHDES has determined that the current limits for the above facilities represent the "most effective use of control technologies" for NOx and SO_2. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

We have several concerns with the Boise Cascade analyses conducted by All4.

Retrofit Factor
All4 assumed a retrofit factor of 1.5 for every woodwaste boiler it evaluated in Oregon. The EPA Control Cost Manual (CCM) recommends that site-specific retrofit factors (greater than the 1.0 default value) should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book Estimating Costs of Air Pollution Control be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The CCM also addresses "Retrofit Cost Considerations" in section 2.6.4.2. In the absence of such a proper analysis, assume a retrofit factor = 1.0, which represents a 30% increase above costs for a "greenfield" project. The All4 blanket application of the maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy.

SCR Equipment Life
All4 assumed a 20-year life for these boilers; for all other woodwaste-fired boilers All4 evaluated in Oregon and Washington, All4 assumed 25-year life. We used the CCM default = 25 years.

[7] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NOx. While two recent determinations for similar facilities in Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

Chemical Engineering Plant Cost Index (CEPCI)
All4 used a 2019 CEPCI = 603.1; the correct CEPCI = 607.5.

Interest Rate
All4 used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.

Operating Costs
All4 overestimated the operating costs of SCR (and SNCR) when it substituted values for "Total operating time for the SCR (t_{op})" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. We participated in the EPA work group that developed the CCM workbooks for NO_X (and SO_2) controls and can advise that it is not appropriate to alter values in the "Design Parameters" spreadsheet because these values should, instead, be generated from the "Data Inputs" spreadsheet and the algorithms that operate on them according to the methods and equations described in the CCM.

The "Total operating time for the SCR (t_{op})" parameter is not meant to be the actual operating time for the control device, which All4 entered directly into the "Design Parameters" spreadsheet. Instead, it represents a method to adjust capacity utilization to actual (or permitted) utilization based upon a fraction (Total System Capacity Factor (CF_{total})) applied to the maximum capacity. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect percent removed from the PSEL or actual conditions instead of percent removed from the emissions that would have resulted from All4's hours of operation.

The basic parameters (on the "Data Inputs" spreadsheet) that define emissions and control costs are:

- maximum heat input rate (QB)
- higher heating value (HHV) of the fuel
- estimated actual annual fuel consumption
- net plant heat input rate (NPHR)
- Number of days the SCR (or SNCR) operates (t_{SCR} or t_{SNCR})
- Number of days the boiler operates (t_{plant})
- Inlet NOx Emissions (NO_{Xin}) to SCR (or SNCR)
- Outlet NOx Emissions (NO_{Xout}) from SCR (or SNCR)

All but "estimated actual annual fuel consumption" are essentially fixed by the boiler, fuel, and control device characteristics. The "Number of days the SCR operates (tSCR)" typically equals "Number of days the boiler operates (tplant)."[8] We adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

For example, the "Total operating time for the SCR (t_{op})" parameter is not meant to be the actual operating time for the control device. Instead, it represents a method to adjust capacity utilization to actual utilization based upon a fraction (Total System Capacity Factor (CF_{total}) applied to the maximum capacity. For the Power Boiler (PSEL), All4's workbook overrode the calculated the

[8] In March 2021, EPA revised the SNCR workbook to include an entry for the "Number of days the boiler operates (tplant)." Until that revision, the SNCR workbook assumed 365 days of plant operation.

Total System Capacity Factor = 0.49 and instead entered 0.97. All4 also overrode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 4311 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 4311 hours. All4 compounded its error by also overriding the calculation of Total NOx removed per year.

All4 included property taxes in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

We applied the CCM workbook and adjusted the "estimated actual annual fuel consumption" to yield the uncontrolled emissions (210 ton/yr) specified by All4. Our results are shown below.

SCR	**Company/Consultant Estimates**	**NPS ARD Estimates**
Unit	PB #1 & #2 & #3	PB #1 & #2 & #3
Emissions Reduction (tpy)	189	190
Total Annual Cost	$ 2,527,428	$ 1,269,194
Cost-Effectiveness ($/ton)	$ 13,373	$ 6,679

Results & Conclusions
Addition of SCR to Power Boilers #1, & #3 #2 would reduce NO_X emissions by 189 ton/yr and be much less expensive that estimated by All4 and its cost-effectiveness is well below the Oregon threshold.

Cascade Pacific Pulp
Halsey Pulp Mill
July 1, 2021

Excerpts from the company submittal dated June 2020

Power Boilers #1 & #2

Power Boiler PM_{10} Emissions
The Nos. 1 and 2 Power Boilers at the Cascade Pacific Pulp (CPP) Halsey Mill fire natural gas and have minimal PM_{10} emissions. The No. 1 Power Boiler is permitted to burn No. 6 fuel oil, but this fuel is only burned during periods of gas curtailment.

Power Boiler NO_X Emissions
The design of the CPP Halsey No. 2 Power Boiler is such that a simple burner replacement may not be feasible. The boiler's cyclopack burner is integrated into the side wall of the boiler and to change the burner, tubing and refractory would have to be reconfigured. Therefore, the cost of LNB/FGR on this boiler would likely be higher than estimated.

Power Boiler SO_2 Emissions
Fuel oil is fired in the No. 1 Power Boiler only when natural gas is curtailed, resulting in lower SO_2 emissions.

Recovery Furnace
The CPP Halsey Mill installed a new air system on their recovery furnace in 2010 and rebuilt the ESP in order to reduce emissions.

Lime Kiln

Lime Kiln SO_2 Emissions
The Mill also no longer fires petroleum (pet) coke in the lime kiln, resulting in lower SO_2 emissions. The CPP Halsey lime kiln's portion of the SO_2 PSEL is 68.4 tpy, but 65.7 tpy of the PSEL is from combustion of pulp mill NCG that contain sulfur compounds. The kiln's venturi scrubber is designed for PM control and has a very short residence time. No caustic is added to this scrubber and the short residence time would preclude achieving significant additional SO_2 control if a caustic solution were used. Although the kiln is the backup control device for NCG combustion, addition of a packed bed scrubber to further reduce SO_2 emissions from this kiln was evaluated (rather than replacing the venturi scrubber with a caustic wet scrubber and potentially decreasing the PM_{10} control efficiency).

SO_2 Economic Impacts
The U.S. EPA's fact sheet on packed bed scrubbers[19] was used to develop a rough estimate of capital and annual costs for a packed bed scrubber on the CPP Halsey lime kiln. The fact sheet indicates that capital cost ranges from $11 to $55 per scfm and annual cost ranges from $17 to $78 per scfm. The flow rate from the CPP Halsey lime kiln is approximately 25,000 scfm. Using the low end of the cost ranges in the fact sheet results in a capital cost estimate of $275,000 and an

annual cost estimate of $425,000 per year. Assuming the packed bed scrubber would achieve 98 percent control of the lime kiln's portion of the SO_2 PSEL of 68.4 tpy, the cost effectiveness is at least $6,340. Installing a packed bed scrubber after the venturi scrubber to achieve additional SO_2 control from periodic NCG combustion in the CPP Halsey lime kiln is not cost effective.

Lime Kiln PM_{10} Emissions

CPP Halsey utilizes a wet scrubber for PM control on its lime kiln. An ESP prior to the wet scrubber would provide additional PM_{10} control and is considered technically feasible.

PAPER MACHINES AND PULP DRYERS

Paper machines and pulp dryers consist of the wet end and the dry end and the combined equipment can be the length of a football field and have many different exhaust points through roof vents or building exhausts. On the wet end, pulp is combined with additives and diluted with water at the head box, applied to the former or wire, where it forms a sheet as the water drains, and then travels to the press and dryer sections (dry end) to remove the remaining water. The paper machines at GP Toledo and IP Springfield and the pulp dryer at CPP Halsey are steam heated and do not have emissions of NO_X or SO_2.

OR DEQ

In a letter dated January 21, 2021, OR DEQ notified CPP of its preliminary determination that their Halsey facility would likely be required to install LNB/Flue Gas Recirculation on their Power boiler #1, and also switch to Ultra Low Sulfur Diesel instead of #6 fuel oil as an emergency backup fuel on site.

ARD Comments

CPP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the power boilers (PB#1 & #2). The All4 application of the maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy.

All4 also overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR (t_{op})" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the PB#1 (PSEL), All4's workbook correctly calculated the Total System Capacity Factor = 0.422 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 3697 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating 8760 hours instead of 3697 hours. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 132.5 tpy) instead of 90% removed from the emissions (286 tpy) that would have resulted from All4's 8760 hours of operation (90% * 286 tpy). Instead, we adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

All4's resulting Total Annual Cost of $1.9 million for PB#1 contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unjustified retrofit factor. (All4 also used a 4.75% interest rate instead of the current bank prime rate =

3.25% as recommended by the CCM.) Operating costs were overestimated by more than a factor of two due to over-riding of the “Total operating time” parameter. All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4’s fuel cost of $5.00/mmBtu exceeds the approximately $4.00/mmBtu Oregon industrial price for natural gas according to the EIA. [9]) Instead of All4’s estimated cost-effectiveness = $16,029/ton; we estimate a Total Annual Cost of $0.75 million = $6253/ton for addition of SCR to remove 121 ton/yr of NO_X. (Even though there was no justification provided for the reheat fuel use rate, we accepted All4’s estimate to estimate reheat cost—please see the attached workbooks.)

The same issues apply to PB#1 at actual conditions as well as PB#2. We applied the SCR CCM workbook to PB#1 & #2 for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for the PSEL cases for both boilers. The cost effectiveness of adding SCR for PB#2 clearly exceeds the OR DEQ threshold under actual conditions. Addition of SCR to PB#1 under actual conditions is slightly above the OR DEQ threshold and the costs of reheating the SCR inlet gas stream should be further investigated.

SCR	**Company/Consultant Analysis**		**NPS ARD Analysis**	
Unit	#1 PB (PSEL)	#1 PB (actual)	#1 PB (PSEL)	#1 PB (actual)
Emissions Reduction (tpy)	119	48	121	48
Total Annual Cost	$ 1,911,460	$ 1,826,543	$ 754,862	$ 565,360
Cost-Effectiveness ($/ton)	$ 16,029	$ 38,292	$ 6,253	$ 11,684

SCR	Company/Consultant Analysis		NPS ARD Analysis	
Unit	#2 PB (PSEL)	#2 PB (actual)	#2 PB (PSEL)	#2 PB (actual)
Emissions Reduction (tpy)	68	5	68	5
Total Annual Cost	$1,916,103	$ 1,028,580	$ 588,791	$ 386,630
Cost-Effectiveness ($/ton)	$ 28,349	$ 204,083	$ 8,617	$ 70,695

Results & Conclusions

- The cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for the PSEL cases for both boilers.
- Addition of SCR to PB#1 under actual conditions is slightly above the OR DEQ threshold and the costs of reheating the SCR inlet gas stream should be further investigated.
- The cost effectiveness of adding SCR for PB#2 clearly exceeds the OR DEQ threshold under actual conditions.
- Addition of SCR to these two boilers could reduce NO_X emissions by 189 tons/yr under PSEL conditions or 53 tons/yr under actual conditions.

[9] Oregon Natural Gas Industrial Price (Dollars per Thousand Cubic Feet) (eia.gov)

International Paper
Springfield Mill
July 1, 2021

Excerpts from the company submittal dated June 2020

The International Paper (IP) Springfield Mill is permitted to fire fuel oil in its lime kiln, boilers, and recovery furnace, but burns natural gas instead, resulting in lower PM_{10} and SO_2 emissions. The Mill no longer fires pet coke in the lime kiln, resulting in lower SO_2 emissions. The Mill is already subject to a Federally enforceable permit limit on SO_2 and NO_X emissions that was implemented in the 2008 Oregon Regional Haze Plan to reduce the visibility impact of the BART-eligible units (including the Power Boiler).

Power Boilers
NO_X Emissions
<u>LNB and FGR for Boiler NO_X Control</u>
Installing LNB/FGR is not considered cost-effective for the IP Springfield Power Boiler. Although the estimated cost per ton is lower than the other boilers when based on its assigned portion of the PSEL, when actual emissions are evaluated, the estimated cost is much higher and above any reasonable cost effectiveness threshold. The IP Springfield Package Boiler already uses LNB and FGR to reduce NO_X emissions.

PM_{10} Emissions
The Package Boiler and the Power Boiler at the IP Springfield Mill burn natural gas, with No. 2 fuel oil as backup fuels for periods of natural gas supply interruption or natural gas curtailment. No PM_{10} controls beyond burning natural gas as the primary fuel and limiting oil firing to periods of curtailment are feasible for these boilers.

Lime Kiln
PM10 Emissions
The IP Springfield Mill uses a dry ESP for control of PM emissions from their lime kiln. An ESP upgrade for additional PM10 control is considered technically feasible.

SO_2 Emissions
The lime kilns provide inherent control of SO_2 through absorption of sulfur by the calcium in the kiln. All the mills fire natural gas as the primary fuel in their lime kilns, which minimizes SO2 emissions, particularly during startup and shutdown. Addition of a wet scrubber with caustic addition (following the ESP) for additional SO2 control was evaluated for the IP Springfield lime kilns (which also burn pulp mill NCG).

SO_2 Economic Impacts
The wet scrubber capital cost for the IP Springfield lime kilns was estimated by scaling the recovery furnace wet scrubber cost in the BE&K report using an engineering cost scaling factor of 0.6 and the ratio of the estimated kiln exhaust flow rate to the estimated exhaust flow rate of

the furnace evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1.

PAPER MACHINES AND PULP DRYERS

Paper machines and pulp dryers consist of the wet end and the dry end and the combined equipment can be the length of a football field and have many different exhaust points through roof vents or building exhausts. On the wet end, pulp is combined with additives and diluted with water at the head box, applied to the former or wire, where it forms a sheet as the water drains, and then travels to the press and dryer sections (dry end) to remove the remaining water. The paper machines at IP Springfield are steam heated and do not have emissions of NO_X or SO_2.

Concentrations of PM are very low in each paper machine vent, as discussed in NCASI Technical Bulletin No. 942, "Measurement of PM, PM_{10}, $PM_{2.5}$ and CPM Emissions from Paper Machine Sources," November 2007 (updated February 2017). PM emissions include both filterable (FPM) and CPM, with the FPM coming primarily from the pulp fibers and the CPM resulting from organics. Limited NCASI test data indicate that the FPM concentrations for paper machine vents average less than 0.0004 gr/dscf at each vent (not including tissue machine vents). There are no known control technologies that would remove particulate matter at such a low concentration. It is expected that pulp dryer vent concentrations would be similarly low or lower because the sheet of pulp is thicker and typically has a higher moisture content than paper. BACT analyses for paper machines and pulp dryers routinely indicate that add-on controls are not feasible. Note that IP Springfield has eliminated the New Fiber Line emission unit (EU-402), which had a PM_{10} PSEL of 427 tpy, so this unit is not evaluated here.

OR DEQ

In a letter dated January 21, 2021, DEQ notified International Paper of its preliminary determination that their Springfield facility would likely be required to install SCR on the Power Boiler (EU-150A) and also take several actions related to restricting alternative or emergency fuels.

ARD Comments

IP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the Power Boiler and the Package Boiler. All4 overestimated capital costs when it assumed a retrofit factor of 1.5 without the justification and documentation required by the CCM and EPA policy.

All4 also overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR (t_{op})" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the Power Boiler (PSEL), All4's workbook correctly calculated the Total System Capacity Factor = 0.797 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 6982 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 6982 hours. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 873.74 tpy) instead of 90% removed from the emissions (986 tpy) that would have resulted from All4's 8760 hours of operation (90%

* 986 tpy). Instead, we adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

All4's resulting Total Annual Cost of $3.6 million for the Power Boiler contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unjustified retrofit factor. (All4 also used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.) Operating costs were overestimated due to over-riding of the "Total operating time" parameter. All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4's fuel cost is 25% higher than the current Oregon industrial natural gas price.[10]) Instead of All4's estimated cost-effectiveness = $4606/ton; we estimate a Total Annual Cost of $1.6 million = $2010/ton for addition of SCR to remove 786 ton/yr of NO_X. (Even though there was no justification provided for the reheat fuel use rate, we accepted All4's estimate to estimate reheat cost—please see the attached workbooks.)

The same issues apply to the Power Boiler at actual conditions as well as the Package Boiler. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for the PSEL cases for both boilers, and for the Power Boiler under actual conditions. The cost effectiveness of adding SCR for the Package Boiler clearly exceeds the OR DEQ threshold under actual conditions.

SCR	Company/Consultant Estimates		NPS/ARD Estimates	
Unit	IP Springfield PB (PSEL)	IP Springfield PB (actuals)	IP Springfield PB (PSEL)	IP Springfield PB (actuals)
Emissions Reduction (tpy)	786	126	786	127
Total Annual Cost	$ 3,621,820	$ 2,895,491	$ 1,580,780	$ 1,117,502
Cost-Effectiveness ($/ton)	$ 4,606	$ 22,924	$ 2,010	$ 8,828

SCR	Company/Consultant Estimates		NPS/ARD Estimates	
Unit	IP Springfield PkgBlr (PSEL)	IP Springfield PkgBlr (actuals)	IP Springfield PkgBlr (PSEL)	IP Springfield PkgBlr (actuals)
Emissions Reduction (tpy)	268	1	268	1
Total Annual Cost	$ 2,130,423	$ 825,603	$ 1,583,260	$ 891,894
Cost-Effectiveness ($/ton)	$ 7,948	$ 655,241	$ 5,906	$ 706,194

Results & Conclusions

- Addition of SCR to the Power Boiler and Package Boiler is much less expensive than estimated by IP and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL operating conditions.

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[10] Oregon Natural Gas Industrial Price (Dollars per Thousand Cubic Feet) (eia.gov)

- Addition of SCR to the Power Boiler is much less expensive than estimated by IP and its cost-effectiveness would not exceed the OR DEQ threshold under actual operating conditions.
- Addition of SCR to the Package Boiler would exceed the OR DEQ threshold under actual operating conditions.
- Addition of SCR to the Power Boiler could reduce NO_X emissions by 786 tons/yr under PSEL conditions or 127 tons/yr under actual conditions.

(From Andrea Stacey)

NPS Air Resources Division Review of Gas Transmission NW Compressor Stations 12 & 13

07/07/2021

Gas Transmission Northwest Compressor Station No. 12:

- The company did not use the most recent 7th edition CCM. Why wasn't the most recent version of the CCM SCR chapter used?

- The company assumed a 75% control efficiency. This seems low for SCR. What is the basis for this assumption? As described below, our analysis assumed 90% control. This is equivalent to a controlled NOx limit of 0.037 lb/MMBtu for unit 12-A and 0.017 lb/MMBtu for unit 12-B. The CCM states: "In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent."

  We reviewed the most recent (2020) CAMD information to verify whether the NPS assumed emission rate at 90% control was reasonable (i.e., achieved in practice) for natural gas-fired combustion turbines—we did not include combined cycle units in this review. There are over 100 combustion turbines in the CAM database with emission rates at or below the 0.017 lb/MMBtu limit assumed in our review. Based on this, we concluded that 90% NOx control by SCR is achievable in practice and reasonable to assume in the cost analysis.[11]

- The company assumed 3% sales tax. Does Oregon charge sales tax for pollution control projects? Please note, the revised 7th edition of the CCM does not include sales tax in the cost analysis.

- The company assumed property taxes for the PCE on each CT. Does Oregon charge property taxes on this equipment? Please note, the revised 7th edition of the CCM does not include property tax in the cost analysis.

- The company assumed a cost of $2,765,000 to $3,712,500 for combustion controls in addition to SCR on the CTs—is it assumed the applicant would need both controls to achieve 75% NOx reductions? What is the basis for this?

- The company assumed $105,326 to $143,628 in administrative charges for each CT. This seems high. (Note when using the revised 7th Edition CCM, the estimated administrative charges are roughly $3000/year in 2019$.) What is the basis for these annual costs?

- The company used a 5% interest rate and a 20-year equipment life. We agree with DEQ that unless additional source-specific documentation can be provided, the current bank prime rate (3.25%) should be assumed. In addition, we used the 30-year equipment life assumption recommended by Oregon DEQ.

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[11] When restricting the dataset to small combustion turbines (< 250 MMBtu/hr heat input) we found six examples of natural gas-fired emission units with SCR achieving lower NOx emission rates than what was assumed in our analysis.

- **<u>NPS Revised Analysis for Station 12:</u>** The NPS re-evaluated the costs of controls for the three turbines at compressor station No. 12 using the more recent 7th edition CCM & fixed the issues noted above. We found the following:

  - Using PSEL assumptions, the costs to add SCR to turbines 12-A and 12-B are significantly lower than DEQ's $10,000/ton threshold at $1,833/ton of NOx removed for unit 12-A and $3,801/ton of NOx removed for unit 12-B. (See attached spreadsheets.) The costs to install SCR on unit 12-C, which is newer than the other two turbines and consequently has far lower NOx emissions, exceeds DEQ's cost threshold when using PSEL assumptions.

  - When using reduced operating scenarios (based on reduced fuel use assumptions), the cost of installing SCR is still below DEQ's cost threshold down to ***16% of full capacity for unit 12-A and 34% of full capacity for unit 12-B***, suggesting that SCR is likely still cost effective under reduced operating scenarios.

  - Therefore, we concur with DEQ's determination documented in a January 21, 2021 letter to the company, that SCR is likely cost effective at units 12-A and 12-B. However, we recommend that DEQ correct some of the additional errors identified in the cost analysis (other than interest rate and equipment life), as this results in SCR being a much more cost effective option than estimated by DEQ or the company. Spreadsheets documenting our revised analyses are attached.

<u>Gas Transmission Northwest Compressor Station No. 13</u>:

- The company did not use the most recent 7th edition CCM. Why wasn't the most recent version of the CCM SCR chapter used?

- The company assumed a 75% control efficiency. This seems low for SCR. What is the basis for this assumption? As described below, our analysis assumed 90% control. This is equivalent to a controlled NOx limit of 0.017 lb/MMBtu for unit 13-D and 0.016 lb/MMBtu for unit 13-C. The CCM states: "In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent."

  We reviewed the most recent (2020) CAMD information to verify whether the NPS assumed emission rate at 90% control was reasonable (i.e., achieved in practice) for natural gas-fired combustion turbines—we did not include combined cycle units in this review. There are over 100 combustion turbines in the CAM database with emission rates at or below the 0.016 lb/MMBtu limit assumed in our review. Based on this, we concluded that 90% NOx control by SCR is achievable in practice and reasonable to assume in the cost analysis.[12]

- The company assumed 3% sales tax. Does Oregon charge sales tax for pollution control projects? Please note, the revised 7th edition of the CCM does not include sales tax in the cost analysis.

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[12] When restricting the dataset to small combustion turbines (< 250 MMBtu/hr heat input) we found six examples of natural gas-fired emission units with SCR achieving lower NOx emission rates than what was assumed in our analysis.

- The company assumed property taxes for the PCE on each CT. Does Oregon charge property taxes on this equipment? Please note, the revised 7th edition of the CCM does not include property tax in the cost analysis

- The company assumed a cost of $2,765,000 for combustion controls in addition to SCR on the CTs—is it assumed the applicant would need both controls to achieve 75% NOx reductions? What is the basis for this?

- The company assumed $105,326 in administrative charges for each CT (13C and 13D). This seems high. (Note when using the revised 7th Edition CCM, the estimated administrative charges are roughly $3000/year in 2019$.) What is the basis for these annual costs?

- The company used a 5% interest rate and a 20-year equipment life. We agree with DEQ that unless additional source-specific documentation can be provided, the current bank prime rate (3.25%) should be assumed. In addition, we used the 30-year equipment life assumption recommended by Oregon DEQ.

o **<u>NPS Revised Analysis for Station 13</u>**: The NPS re-evaluated the costs of controls for the three turbines at compressor station No. 13 using the more recent 7th edition CCM & fixed the issues noted above. We found the following:

  - Using PSEL assumptions, the costs to add SCR to turbines 13-C and 13-D are significantly lower than DEQ's $10,000/ton threshold at $4,074/ton of NOx removed for unit 13-C and $3,887/ton of NOx removed for unit 13-D. (See attached spreadsheets.)

  - When using reduced operating scenarios (based on reduced fuel use assumptions), the cost of installing SCR is still below DEQ's cost threshold down to ***37% of full capacity for unit 13-C and 35% of full capacity for unit 13-D***, suggesting that SCR is likely still cost effective under reduced operating scenarios.

  - Therefore, we concur with DEQ's determination, documented in a January 21, 2021 letter to the company, that SCR is likely cost effective for units 13-C and 13-D. However, we recommend that DEQ correct some of the additional errors identified in the cost analysis (other than interest rate and equipment life), as this results in SCR being a much more cost effective option than estimated by DEQ or the company. Spreadsheets documenting our revised analyses are attached.

(From Debra Miller)
April 2, 2021

Thanks for sharing the four factor analyses with us. I have reviewed the analysis for the Roseburg FP Dillard facility and the Biomass One facility and have some initial feedback.

The costs for SNCR at the Roseburg FP Dillard facility appear to be reasonable as presented in the four factor analysis, but it looks like an interest rate of 4.75% was used, rather than the current bank prime rate of 3.25% as recommended by the control cost manual. In addition, it looks like the analysis relied upon an old reference to calculate capital costs (*USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR),* issued July 15, 2003.) For most other calculations the consultant appears to have used equations from the EPA control cost manual from 2017 so it is unclear why a different method was chosen for the capital costs. The capital costs should be estimated using the methods from the control cost manual. There is also an EPA worksheet available to estimate SNCR costs that employs the guidance in the EPA manual.

The Dillard analysis dismisses the use of SCR for NOx emissions reduction as technically infeasible because of the potential for wood combustion byproducts to foul or plug the catalyst. However, there are other facilities powered by wood combustion that have successfully employed tail-end SCR. One is the Bridgewater electrical generating facility in Bridgewater, New Hampshire, which uses a 250 mmbtu/hr wood-fired boiler. An additional New Hampshire facility, Burgess BioPower, uses SCR for NOx control and has a limit of 0.06 lb NOx/MMbtu. Tail-end SCR is technically feasible for the Dillard facility and should be evaluated to determine if it is cost effective. I ran cost estimates using the EPA recommended worksheet for the three boilers and it appears the cost for SCR may be reasonable (see attached example). It wasn't completely clear to me from the four factor analysis how much natural gas vs. wood is combusted, but the SNCR analysis appeared to use the heating value of wood so I assumed that it is the primary fuel.

I reviewed the BiomassOne analysis as well. There were two cost estimates provided for SCR—one in the four factor analysis and a separate, more recent response based upon a vendor estimate from Halgo Power. Looking at the more recent estimate, BiomassOne used an interest rate of 4.75% instead of the current prime rate of 3.25% and assumed a 20-year lifetime rather than 30 years as recommended in the EPA control cost manual. The analysis indicated that Halgo's recommendation was a 20-year useful life but I didn't see that in the attached estimate. Using the company's calculation methods with an interest rate of 3.25% and useful life of 30 years brings the cost per ton to about $7,000.

(From Debra Miller)
June 3, 2021

I looked at your initial determination in the SIP for the Roseburg Forest Products—Dillard facility. I sent some feedback on their four factor analysis earlier, which I attached below. I see that the SIP says that SNCR would be cost effective on all three boilers, and I agree. I was curious whether tail-end SCR was ever evaluated. As I mentioned earlier, there are some other biomass boilers using tail-end SCR. I ran some estimates for both SNCR and SCR using the EPA costing worksheets, and the results suggest that SCR may be even more cost effective than SNCR given the greater NOx reduction ($2,800-$3,500 per ton). I have attached some cost estimates for comparison.

The SIP also indicates that SCR is cost effective for the two boilers at BioMass One, and I agree with that as well. I used EPA's most recent cost estimation worksheet (7th edition of the Control Cost manual) rather than the company's methods. I attached examples for the South Boiler using the PSEL as well as actual emissions. The results suggest that SCR is more cost effective than indicated by the company's analysis ($5,000 to $6,900 per ton).

United States Department of the Interior

NATIONAL PARK SERVICE
Interior Regions 8, 9, 10, and 12
333 Bush Street, Suite 500
San Francisco, CA 94104-2828

IN REPLY REFER TO:
1.A.2 (PW-NR)

October 29, 2021

Oregon Department of Environmental Quality
Attention: Karen F. Williams
700 NE Multnomah St., Room 600
Portland, OR 97232-4100
email: RHSIP2021@deq.state.or.us

Dear Ms. Williams:

Thank you for the opportunity to review the proposed Oregon Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018-2028). Starting in January 2020, the National Park Service (NPS) engaged in early, informal consultation with the Oregon Department of Environmental Quality regarding SIP development. We appreciate the extensive efforts Oregon invested to engage early with the NPS. In consideration of the public review draft of the Oregon SIP, we provide additional comments which reiterate some of our initial recommendations and respond to new information.

Significant opportunities for emission reductions are available that could further improve the draft SIP. Specifically:

- We recommend Oregon require the most significant pollution reductions found to be technically feasible and cost-effective for facilities reviewed.
- The draft SIP would be strengthened by including a thorough technical justification for compliance strategies that achieve fewer emission reductions than originally proposed. See Enclosure 1 for detailed technical comments. We have also included Enclosure 2, a zipped file of calculation worksheets supporting NPS cost-effectiveness analyses.
- We recommend that control determinations be based on the results of four-factor analysis, rather than adjustments that allow facilities to retroactively avoid selection.

As we shared in our earlier feedback, the NPS appreciates that Oregon has: 1) selected a reasonable number of facilities to analyze for potential emission reductions; 2) tightened permitted emission limits to be more in-line with actual emissions; 3) established a reasonable cost-effectiveness threshold for emission controls; and 4) chose not to adjust glidepath goals for international emissions. We recognize that the draft SIP requires some reductions in haze-causing emissions which will make progress toward reducing haze in the region.

The NPS manages 48 of the 156 federally designated Class I areas across the country where visibility is an important attribute. NPS-managed Class I areas affected by haze-causing emissions from Oregon include Crater Lake National Park in Oregon, Mount Rainier National Park in Washington, Redwood National Park and Lava Beds National Monument in California, and Craters of the Moon National Monument & Preserve in Idaho. Haze can significantly diminish the visitor experience in these iconic parks that offer awe-inspiring vistas of snowcapped mountains, rugged volcanic landscapes, giant redwoods, and azure blue lakes.

We encourage Oregon to fully document its rationale for control decisions and to take every opportunity to reduce haze-causing emissions. The cumulative benefits of emission reductions from many sources are necessary to achieve the Clean Air Act and Regional Haze Rule goal to "prevent future and remedy existing visibility impairment" in Class I areas. Oregon analyses have identified additional emission reductions that would make further progress toward this goal. Oregon has an opportunity to improve the effectiveness of their Regional Haze SIP by choosing to require these cost-effective emission controls identified using the four statutory factors. These incremental steps will contribute towards aligning Crater Lake National Park and other NPS Class I areas in the region with reasonable progress goals.

We appreciate the opportunity to comment and look forward to continued work with Oregon for clean air and clear views. For questions or further information, contact Jalyn Cummings (jalyn_cummings@nps.gov) or Melanie Peters (melanie_peters@nps.gov).

Sincerely,

Cindy Orlando
Acting Regional Director
National Park Service, Interior Regions 8, 9, 10, and 12

Enclosures (2)
Enclosure_1_NPS-OR_RH-SIP-Feedback_11.2021_1.pdf
Enclosure 2_NPS-OR_RH_CalculationSpreadsheets.zip

cc: Stephanie Burkhart, Acting Deputy Regional Director
Denise Louie, Regional Natural Resources & Science Lead
Jalyn Cummings, Regional Air Resources Program Manager
Melanie Peters, Air Resources Division Regional Haze Lead

National Park Service (NPS) Regional Haze SIP feedback for the Oregon Department of Environmental Quality

November 1, 2021

Contents

1 General/Process

Under the Clean Air Act (§§169A and B) and Federal Regional Haze Rule (40 CFR §51.308), states are required to develop SIPs and engage substantively with agencies that manage national parks and wildernesses designated as Class I areas. States are also required to update SIPs every 10 years to address air pollution and to ensure progress towards achieving the goal for "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."

1.1 Consultation

The NPS participated in informal early engagement with the Oregon Department of Environmental Quality (ODEQ) regarding SIP development beginning in January of 2020. This included a preliminary coordination meeting on May 25th, 2021 and subsequent written documentation of NPS feedback on July 1st, 2021. In addition, NPS staff provided ongoing technical feedback on individual facility four-factor analyses as documented in the draft Oregon SIP. We appreciate the extensive efforts that Oregon invested in early engagement with the NPS.

As we shared in our earlier feedback, we appreciate that Oregon: 1) selected a reasonable number of sources to analyze for potential emission reductions, 2) tightened permitted emission limits to be more in-line with actual emissions, 3) established a reasonable cost-effectiveness threshold for emission controls, and 4) chose not to adjust glidepath goals for international emissions. We recognize that the draft SIP requires some haze-causing emission reductions and will make progress toward reducing haze in the region.

Oregon's strategies to address visibility impairment presented in the current draft SIP were first shared with the NPS when the draft was made available for public comment. In consideration of the public review draft of the Oregon SIP, we provide additional comments which reiterate some of our initial recommendations and respond to new information.

1.2 Revised Control Determinations

Significant opportunities for emission reductions are available that could improve the draft SIP. Specifically:

- We recommend Oregon require the most significant pollution reductions found to be technically feasible and cost-effective for facilities reviewed.
- The draft SIP would be strengthened by including a thorough technical justification for compliance strategies that achieve fewer emission reductions than originally proposed. Enclosure 2 is a zipped file of calculation worksheets supporting NPS cost-effectiveness analyses.
- We recommend that control determinations be based on the results of four-factor analysis, rather than adjustments that allow facilities to retroactively avoid selection.

1.3 Editorial Note

On page 100 of the draft SIP, regarding responses to NPS comments, the NPS is quoted as saying:

> "The analysis relied upon an old reference to calculate capital costs (USEPA Air Pollution Control Technology Fact Sheet (EPA- 452/F-03-031) for selective non-catalytic The capital costs should be estimated using the methods from the control cost manual. reduction (selective non-catalytic reduction, or SNCR), issued July 15, 2003."

The NPS comment, in fact, read:

> "The analysis relied upon an old reference to calculate capital costs (USEPA Air Pollution Control Technology Fact Sheet (EPA- 452/F-03-031) for selective non-catalytic reduction (SNCR), issued July 15, 2003. The capital costs should be estimated using the methods from the control cost manual."

2 Wood Product Facilities Feedback

The wood products facilities selected by ODEQ for four-factor analyses (4FA) are:

- Collins Wood Products, L.L.C.
- Ochoco Lumber Company
- Pacific Wood Laminates, Inc.
- Swanson Group Mfg. LLC
- Woodgrain Millwork LLC – Particleboard
- Gilchrist Forest Products
- **Boise Cascade Wood Products, LLC - Elgin Complex**
- **Georgia Pacific - Wauna Mill**
- **Cascade Pacific Pulp, LLC - Halsey Pulp Mill**
- **Boise Cascade Wood Products, LLC - Medford**
- **International Paper - Springfield**
- **Georgia-Pacific – Toledo LLC**
- Roseburg Forest Products - Dillard
- Willamette Falls Paper Company
- Columbia Forest Products, Inc.

The four-factor analyses for the facilities highlighted in **bold type** share many similarities identified in feedback from NPS to ODEQ; these facilities are further discussed below.

In its draft RH SIP, regarding the Boise Cascade Elgin facility, ODEQ stated:

> *DEQ acknowledges additional corrections that NPS recommends, such as retrofit factor, CEPCI, operating costs, reagent costs and property tax; however, DEQ generally did not correct for such factors if DEQ had already concurred on the technical infeasibility of*

certain controls or was working with facilities to pursue alternative methods of emission reductions.

For other wood products facilities (BC-Medford, GP-Wauna, GP-Toledo, CP-Halsey), ODEQ simply stated:

Please see DEQ Response to Boise Cascade – Elgin.

We note that ODEQ may have overlooked a response to our comments on IP-Springfield on page 97 of the draft SIP.

ODEQ conclusions about the NPS's recommendations for additional NO_x controls (selective catalytic reduction, or SCR) should be explained in greater detail, this would strengthen the draft SIP.

ODEQ has applied one set of circumstances to all of the boilers at these facilities. The only facilities with woodwaste-fired boilers are the two Boise Cascade veneer mills and the fluidized bed boiler at GP's Wauna mill. It is likely that addition of SCR to these boilers would require location downstream of the particulate controls and a method to reheat the gas stream. The other eight power boilers at these facilities are all fired with natural gas and there is no technical concern regarding direct addition of SCR.

If ODEQ identifies "alternative methods of emission reductions," these methods should be at least as effective at reducing NO_x emissions as the cost-effective applications of SCR. We recommend that ODEQ fully document how the alternatives contained in the draft SIP meet this test.

In summary, we shared with ODEQ the following early engagement feedback regarding four factor analyses of wood product facilities:

- In ODEQ's review of the power boilers at Georgia Pacific's (GP's) Toledo mill, ODEQ changed GP's 1.5 retrofit factor "to 1 because there is no vendor data" consistent with EPA's Control Cost Manual (CCM) spreadsheet which advises "You must document why a retrofit factor of (>1.0) is appropriate for the proposed project."
- We generally agree with ODEQ's decision for GP-Toledo. Acceptance of the 1.5 retrofit factor should also be justified for the other facilities with documentation of cost-effectiveness analysis. Application of an un-documented retrofit factor significantly inflates the capital cost of SCR.
- A 20-year life for the Boise Cascade boilers was assumed, in contrast a 25-year life was assumed for all other OR and WA woodwaste-fired boilers. This difference should be explained.
- For the Boise Cascade boilers, a 2019 Chemical Engineering Plant Cost Index (CEPCI) = 603.1 was used; the correct CEPCI = 607.5.
- A 4.75% interest rate was applied instead of the current bank prime rate of 3.25% as recommended by the CCM.

- The operating times calculated by the CCM spreadsheets were over-ridden by the paper mills and higher values were substituted. This resulted in significant overestimation of operating costs that are based upon hours of operation.
- The reagent (ammonia) cost/gallon used by the paper mills in their SCR spreadsheets is an order of magnitude greater than the default value contained in the CCM SCR spreadsheet. The higher reagent cost should be documented or revised to be consistent with the CCM default cost/gallon.
- The paper mills included costs for reheating the boiler outlet gas streams to facilitate application of SCR. While reheat may be necessary if the SCR is applied downstream of emission control devices that reduce the temperature of the gas stream, it would not be necessary for SCR applied to the natural gas-fired power boilers common to these mills. Where reheat is appropriate, e.g., for a biomass-fired boiler with particulate controls, the amount of natural gas needed to reheat the gas stream should be explained and justified. It is our understanding that the only biomass-fired boilers were the Fluidized Bed Boiler at GP-Wauna and the boilers at the Boise Cascade facilities. Analyses would benefit from an explanation of the reheat costs.
- Property taxes were included in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

In its draft RH SIP, ODEQ noted that:

DEQ adjusted cost estimates for consistency among emissions units, including adjustment to current prime rate (3.25%), 30-year lifetime, and emissions at plant site emission limit (PSEL).

- DEQ removed sales tax costs from FFA analysis as Oregon has no sales tax.
- DEQ acknowledges additional corrections that NPS recommends, such as retrofit factor, CEPCI, operating costs, reagent costs and property tax; however, DEQ generally did not correct for such factors if DEQ had already concurred on the technical infeasibility of certain controls or was working with facilities to pursue alternative methods of emission reductions.

We appreciate the work ODEQ has done to improve the four factor analyses for individual facilities. A more rigorous demonstration of SCRs technical infeasibility would substantiate the decision to move away from requiring this control technology where that was done. Barring such a demonstration, we recommend the application of SCR to reduce NO_x emissions should be required.

3 Facility Specific Feedback

3.1 Owens-Brockway Glass Container Inc.

According to the Oregon draft SIP:

> *In a letter dated October 27, 2020, DEQ concurred with Owens-Brockway's findings in FFA submitted on June 12, 2020, that costs of installing controls were reasonable. Specifically, DEQ concurred with the findings that combined control of NO_x, SO_2 and PM by catalytic ceramic filters is cost-feasible for the facility's glass-melting furnaces A and D.*
>
> *Owens-Brockway informed DEQ by an April 27, 2021, letter that the facility intended to shut down Furnace A permanently and request Furnace A and its emissions units' removal from their Title V permit. Rather than install controls, Owens-Brockway chose the alternative compliance option to lower PSELs. On August 8, 2021, Owens Brockway entered a stipulated agreement and order with DEQ to accept federally enforceable reductions of combined PSELs for Round 2 Regional Haze pollutants to bring the facilities Q/d below 5.00.*

NPS Comment: We agree that the permanent shutdown of Furnace A is an actual emissions reduction at the facility. We also observe that additional emission controls for furnace D are cost effective and request that Oregon require these controls or equivalent reductions. Alternatively, an analysis demonstrating that PSEL reductions agreed to will meet this standard would improve the SIP.

The ODEQ agreement stipulates in part that:

- *On and after January 1, 2022, the permittee shall comply with the following PSELs, which apply to each 12 consecutive calendar month period after that date: 55 tons/year PM_{10}, 137 tons/year NO_x, and 108 tons/year SO_2.*
- *On July 21, 2025, the permittee's PSELs for the following pollutants are: 274.95 tons/year PM_{10} + NO_x + SO_2, which results in a Q/d = 4.99.*

NPS Comment: Based on the company's own analysis (dated June 12, 2020) the cost of catalytic ceramic filters on Furnace D alone are $5,035/ton to control NO_x, SO_2, and PM simultaneously. A Dry Scrubber + ESP + SCR on Furnace D alone would be $6,883/ton to control NO_x, SO_2, and PM. (See Table 11 in the company's four-factor analyses). The company used a 7% interest rate and a 20-year equipment life. Even with the higher interest rate, these costs are well within ODEQ's cost-effectiveness threshold for furnace D.

3.2 Boise Cascade Wood Products, LLC - Elgin Complex

3.2.1 NPS Review of Eglin

From the draft SIP, ODEQ:

In a letter dated January 21, 2021, DEQ notified Boise Cascade Wood Products of its preliminary determination that their Elgin facility would likely be required to install Selective Catalytic Reduction on Boilers 1 and 2. Boise Cascade provided DEQ a technical memo dated April 19, 2021 in which Boise Cascade's consultant concluded that SCR was not technically feasible on boilers at the Elgin facility.

NPS Comment: The Boise Cascade letter reiterated several concerns from its initial submittal:

- SCR is not identified in the EPA RBLC database as an existing control technology deployed on biomass-fired industrial boilers.
- The temperatures of boiler flue-gas exiting the Facility's Dry Electrostatic Precipitator (DESP) are generally below the minimum SCR operating temperature and well below the optimum operating temperatures for catalyzed reactions.
- Flue-gas reheating would be required for effective SCR operation, which would result in additional energy usage and GHG emissions.
- The presence of alkali metals and other constituents found in wood could poison catalysts.
- There is risk of ammonia slip, oxidation of CO to CO_2, and formation of sulfuric acid mist emissions associated with injection of ammonia.

As a point of reference, we can share that SCR has been applied to biomass-fired boilers located downstream of the particulate control device with reheating. The excerpt below illustrating this is from the New Hampshire draft Regional Haze SIP:

> **Burgess BioPower**: The biomass unit at this facility was subject to NNSR for NO_x at the time of their initial permitting; hence, the NO_x limit was established as the LAER[1] based limit. The NO_x limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NO_x/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for SO_2 at the time of its initial permitting in 2010; hence, the SO_2 limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. SO_2/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the SO_2 BACT. Sorbent injection was installed for acid gas control but is not used to control SO_2 emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs SO_2/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the emission limit for SO_2. For this reason, NHDES has determined that the current limits for the above facilities represent the "most effective use of control technologies" for NO_x and SO_2. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

[1] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NO_x. While two recent determinations for similar facilities in Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

> The presence of catalyst poisons should be evaluated by stack testing instead of relying upon speculation. Ammonia slip should not be an issue with SCR and acid mist emissions would not be a concern with this very-low-sulfur fuel. Any hazard associated with handling and storage of ammonia can be addressed with proper training, operation, and maintenance.

Boise Cascade provided a Technical Memorandum from Maul Foster Alongi—their findings are summarized below:

- There are no applications of SCR controls on a wood-fired boiler that are comparable in size to Facility boilers.
- SCR controls have not been implemented on load-following boilers.
- SCR controls have not been implemented on primarily bark-fired boilers.
- SCR controls have not been implemented on any wood-fired boilers in Oregon.
- Oregon soils often have higher concentrations of metals that are catalyst poisons than other locations where SCR has been implemented. These metals are accumulated in the wood burned in the boilers
- The average flue-gas temperature following the Facility's DESP is less than the typical operating temperature for SCR and well below the optimal temperature range for catalytic reduction.
- For the reasons described above, SCR was determined to not be technically feasible for the Facility's wood-fired boilers.

The temperature (reheat) and poisoning (stack test) concerns raised are addressed in the New Hampshire RH SIP excerpt above. While SCR has not been applied to comparably-sized, load-following, bark-fired boilers it certainly may be possible and we encourage ODEQ to thoroughly explore this potential.

ODEQ:

Boise Cascade also provided DEQ a second technical memo dated May 10, 2021, in which a vendor provided their recommendations regarding the feasibility and effectiveness of other NO_x reduction technologies including low oxygen operation, air staging, flue gas recirculation natural gas co-firing, and steam or water injection.

Rather than install SCR, Boise Cascade chose an alternative compliance option to accept federally enforceable requirements to install and continually operate combustion controls, monitoring equipment and accept emission limitations to reduce round II regional haze pollutants from the Elgin facility. On August 12, 2021, Boise Cascade entered into a stipulated agreement and order with DEQ. The final order, included in Appendix E, requires the following and contains other requirements and provisions:

- *On and after July 31, 2022, the permittee's PSELs for SO_2 are 17.1 tons/year*
- *Within three months of the signed order, permittee shall install a Continuous Emission Monitoring System on Boiler 1 and Boiler 2 to measure NO_x emissions.*
- *By July 31, 2023, the permittee shall begin installation of combustion improvement project(s) designed to achieve emissions reductions of NO_x from Boiler 1 and Boiler*

2 by 15%, and permittee shall begin monitoring NO_x emissions using the CEMS to determine actual NO_x emission reductions achieved by controls.

- *If initial boiler combustion improvement project(s) fail to achieve a minimum 15% NO_x reduction, the permittee may implement additional combustion improvement projects to achieve 15% NO_x reduction or accept PSEL reductions.*
- *By December 31, 2025, the permittee shall submit 12 months of CEMS data to DEQ demonstrating the NO_x emission reductions achieved by combustion controls, and shall propose a NO_x limit based on the achieved reductions.*
- *If combustion controls fail to achieve 15% NO_x reduction, the permittee must reduce PSEL (PM_{10}+NO_x+SO_2) to a level that would achieve a Q/d commensurate with a 15% Boiler NO_x reduction.*
- *On and after March 31, 2026, the permittee must comply with emission limits and the PSEL established under the conditions listed in the order.*

NPS Comment: Boise Cascade also provided a report by CPL Combustion & Control Systems (CPL) in which it says "…CPL determined SCR was not technically feasible for control of NO_x from the Facility's boiler system…" The CPL report (excerpted below) does not appear to address EPA's requirements for a technical infeasibility demonstration:

> The technical difficulties described above apply generally to biomass boilers. Advanced technologies and auxiliary heating of the tail-end flue gas have been developed recently in an attempt to overcome these difficulties. However, the wide load swings experienced by plywood mill boilers result in unstable exhaust temperatures and would make it particularly difficult to control the flue gas temperature and reagent injection rate needed to ensure appropriate NO_x reductions while avoiding excessive ammonia slip. For these reasons, SCR technology has not been successfully demonstrated for a load-following spreader-stoker boiler with load swings comparable.

Modern control systems are likely capable of overcoming the difficulties described by CPL. We recommend that Boise Cascade provide an analysis of technical feasibility from an established SCR vendor.

3.2.2 Boise Cascade-Elgin SCR analyses

NPS Comments:

We have questions regarding the Boise Cascade-Elgin analyses for addition of SCR.

<u>Retrofit Factor</u>

Analyses assumed a retrofit factor of 1.5 for all woodwaste boilers. The EPA Control Cost Manual (CCM) recommends that site-specific retrofit factors (greater than the 1.0 default value) should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book <u>Estimating Costs of Air Pollution Control</u>. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The CCM also addresses “Retrofit Cost Considerations” in section 2.6.4.2. In the absence of such an analysis standard practice is to assume a retrofit factor = 1.0, which represents a 30% increase above costs for a “greenfield” project.

SCR Equipment Life

Boise Cascade analyses assumed a 20-year life for these boilers. We used the CCM default of 25 years in our calculations (EPA CCM).

Chemical Engineering Plant Cost Index (CEPCI)

Boise Cascade analyses used a 2019 CEPCI = 603.1. We used the recommended CEPCI = 607.5 (EPA CCM).

Interest Rate

Boise Cascade analyses used a 4.75% interest rate. We used the CCM recommended current bank prime rate = 3.25% (EPA CCM).

Operating Costs

Boise Cascade analyses overestimated the operating costs of SCR (and SNCR) by substituting values for “Total operating time for the SCR (t_{op})” and “Total NO_x removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. We participated in the EPA work group that developed the CCM workbooks for NO_x (and SO_2) controls and advise that values in the “Design Parameters” spreadsheet should be generated from the “Data Inputs” spreadsheet and the algorithms that operate on them according to the methods and equations described in the CCM.

The “Total operating time for the SCR (t_{op})” parameter is not meant to be the actual operating time for the control device, which was entered directly into the “Design Parameters” spreadsheet. Instead, it represents a method to adjust capacity utilization to actual (or permitted) utilization based upon a fraction (Total System Capacity Factor (CF_{total}) applied to the maximum capacity. This issue was compounded by also over-riding the calculation of Total NO_x removed per year to reflect percent removed from the PSEL or actual conditions instead of percent removed from the emissions that would have resulted from hours of operation.

The basic parameters (on the “Data Inputs” spreadsheet) that define emissions and control costs are:

- maximum heat input rate (QB)
- higher heating value (HHV) of the fuel
- estimated actual annual fuel consumption
- net plant heat input rate (NPHR)
- Number of days the SCR (or SNCR) operates (t_{SCR} or t_{SNCR})
- Number of days the boiler operates (t_{plant})
- Inlet NO_x Emissions (NO_{xin}) to SCR (or SNCR)
- Outlet NO_x Emissions (NO_{xout}) from SCR (or SNCR)

All but “estimated actual annual fuel consumption” are essentially fixed by the boiler, fuel, and control device characteristics. The “Number of days the SCR operates (tSCR)” typically equals “Number of days the boiler operates (tplant).”[2] We adjusted “estimated actual annual fuel consumption” to yield the uncontrolled emissions specified by the Boise Cascade Elgin analysis.

For example, rather than the actual operating time for the control device, “total operating time for the SCR (t_{op})” parameter represents a method to adjust capacity utilization to actual utilization based upon a fraction (Total System Capacity Factor (CF_{total}) applied to the maximum capacity. For the Power Boiler (PSEL), the Boise Cascade Elgin workbook correctly calculated the Total System Capacity Factor = 0.976 but overrode that result by entering 8,760 hours for Total operating time for the SCR instead of the value of 8,550 hours that would have been calculated by the spreadsheet. The workbook then calculated annual operating costs as if the SCR were operating at maximum capacity 8,760 hours instead of 8,550 hours. This was compounded by also overriding the calculation of Total NO_x removed per year to reflect 90% removed from the PSEL (90% * 170 tpy) instead of 90% removed from the emissions (153 tpy) that would have resulted from the 8,760 hours of operation (90% * 153 tpy).

Property taxes were included in several analyses prepared for Boise Cascade Elgin. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment so they were excluded from NPS estimates.

CPL presented information on two gas re-heat options for addition of SCR: regenerative heating or natural gas heating. According to CPL:

> In order to raise the flue gas to temperatures high enough for the SCRs to work, over 11.0 MMBtu/hr. of natural gas would be used to re-heat the flue gas just to get the SCR system to work.

We applied the CCM workbook and adjusted the “estimated actual annual fuel consumption” to yield the uncontrolled emissions (170 ton/yr) specified. Although reheat costs were not included in the facility analysis, we used the CPL estimate (11 mmBtu/hr) and the July 2021 EIA Oregon industrial natural gas price ($5.16) in our cost estimate calculations (see Table 1).

Table 1. Boise Cascade Wood Products, LLC - Elgin Complex

SCR	**Company/Consultant Estimates**	**NPS Estimates**
Unit	PB #1 & #2	PB #1 & #2
Total Annual Cost	$ 1,450,706	$ 1,340,205
Emissions Reduction (tpy)	152	153
Cost-Effectiveness ($/ton)	$ 9,538	$ 8,777

[2] In March 2021, EPA revised the SNCR workbook to include an entry for the “Number of days the boiler operates (tplant).” Until that revision, the SNCR workbook assumed 365 days of plant operation.

3.2.3 NPS Results & Conclusions for Boise Cascade-Elgin

Addition of SCR to Power Boilers #1 & #2 would reduce NO_x emissions by 153 ton/yr and is well below the Oregon cost threshold.

3.3 Georgia Pacific Wauna Mill

3.3.1 Summary of NPS GP Wauna Review

From the draft SIP, ODEQ:

Georgia Pacific chose an alternative compliance option to accept a federally enforceable requirement to install controls and associated monitoring equipment, and to accept emission limitations to reduce round II regional haze pollutants from the Wauna facility. On August 9, 2021 Georgia Pacific entered a stipulated agreement and order with DEQ. The order is included in Appendix E. The order requires the following and contains other requirements and provisions:

- *On August 1, 2022 PSELs are: PM_{10} = 1,077 tons/year; NO_x = 2,019 tons/year; SO_2 = 913 tons/year.*
- *On December 31, 2024, PSELs are PM_{10} = 1,077 tons, NO_x = 1,999 tons, and SO_2 = 913 tons.*
- *On July 31, 2026, PSELs are PM_{10} = 1,077 tons, NO_x = 1,413 tons, and SO_2 = 913 tons.*
- *For the Paper Machine 5 Yankee Burner, by December 31, 2024, permittee shall replace existing Yankee burner with a Low NO_x Burner achieving <= 0.03 lb/MMBtu.*
- *For the TAD1 and TAD 2 burners on Paper Machines 6 and 7, permittee shall have a NO_x emission rate no greater than 0.06 Ib/MMBtu and shall use this emission rate for PSEL compliance.*
- *For Power Boiler - 33, by December 31, 2022, permittee shall meet with DEQ to discuss the technical details of the low NO_x burner, flue gas recirculation, and CEMS installation to determine what permitting permittee shall need prior to construction.*
- *As expeditiously as practicable, but not later than July 31, 2026, permittee shall install low NO_x burners and flue gas recirculation in order to achieve an emission rate no greater than 0.09 Ib/MMBtu on a seven-day rolling basis.*
- *Within one year of completing the Power Boiler project, but not later than July 31, 2026, permittee shall install a CEMS to measure the emissions of NO_x from Power Boiler - 33.*
- *Upon DEQ's approval of the CEMS certification, permittee shall use data collected from the CEMS to demonstrate compliance with the applicable NO_x PSEL.*

NPS Comments:

Based upon information submitted by GP, actual Power Boiler NO_x emissions are 266 tpy (@ 0.465 lb/mmBtu) and the proposed 0.09 lb/mmBtu NO_x emission rate represents an 81%

reduction (215 tpy). As shown below in Table 2, addition of SCR is highly cost-effective and would reduce actual emissions by 240 tpy.

Table 2. GP -Wauna Power Boiler

SCR	**Company/Consultant Estimates**		**NPS Estimates**	
Unit	Pwr Blr (PSEL)	Pwr Blr (actual)	Pwr Blr (PSEL)	Pwr Blr (actual)
Current Emission Rate (lb/mmBtu)	0.341	0.465	0.341,	0.341
Current Emissions (tpy)	589	266	589	266
Controlled Emission Rate (lb/mmBtu)	0.034	0.046	0.034	0.047
Emission Reduction (tpy)	532	239	530	240
Total Annual Cost	$ 4,444,671	$ 2,942,622	$ 854,578	$ 719,058
Cost-Effectiveness ($/ton)	$ 8,353	$ 12,317	$ 1,612	$ 3,002

Although GP submitted cost-effectiveness estimates for the biomass-fired Fluidized Bed Boiler (FBB), the draft SIP does not discuss controlling this boiler. GP included costs for reheating the FBB SCR inlet gas stream with no explanation of how this cost was derived. Still, we accepted the estimate of reheat cost see the attached workbooks for calculations. Instead of GPs estimated cost-effectiveness of $15,069/ton, we estimate a Total Annual Cost of $1.4 million = $9,051/ton for addition of SCR to remove 155 ton/yr of NO_x (see Table 3).

Table 3. GP-Wauna Fluidized Bed Boiler

SCR	**Company/Consultant Estimates**		**NPS Estimates**	
Unit	FBB (PSEL)	FBB (actual)	FBB (PSEL)	FBB (actual)
Current Emission Rate (lb/mmBtu)	0.256	0.467	0.256	0.467
Current Emissions (tpy)	224	171	224	172
Controlled Emission Rate (lb/mmBtu)	0.026	0.047	0.026	0.0467
Emissions Reduction (tpy)	202	153	202	155
Total Annual Cost	$ 3,043,381	$ 3,222,435	$ 1,982,073	$ 1,416,263
Cost-Effectiveness ($/ton)	$ 15,069	$ 21,000	$ 9,823	$ 9,165

3.3.2 NPS Results & Conclusions for GP-Wauna

- We recommend that ODEQ’s draft SIP more thoroughly address emissions from GP Wauna by including an analysis of emissions from the Fluidized Bed Boiler.
- The safety and health concerns expressed by ODEQ relative to adding SCR to the Power Boiler can be addressed by proper operation and maintenance. The water, wastewater concerns are not relevant to SCR. Electricity and natural gas costs were included in the cost-effectiveness analyses.
- Addition of SCR to the Power Boiler and the Fluidized Bed Boiler is much less expensive than estimated by GP, and its cost effectiveness is within the ODEQ threshold under PSEL or actual operating conditions.

- Addition of SCR to these two boilers could reduce NO_x emissions by 732 tons/yr under PSEL conditions or 395 tons/yr under actual conditions. Instead, ODEQ's proposal would reduce the PSEL by 606 tpy and actual emissions by 215 tpy.

3.4 Georgia Pacific Toledo Mill

3.4.1 Summary of NPS GP Toledo Review

ODEQ:

In a letter to DEQ dated April 30, 2021, Georgia Pacific stated concerns with installing SCR or SNCR on the power boilers based on undesirable associated effects such as health exposure and safety risk of handling and storing aqueous ammonia, ammonia slip, increased water usage and subsequent wastewater disposal, and higher electricity and natural gas use.

On August 9, 2021, Georgia Pacific Toledo entered a stipulated agreement and order, contained in Appendix E, that required the following and contains other requirements and provisions:

- *Either complete a NO_x reduction project that includes the installation of low NO_x burners, flue gas recirculation and CEMS on the three Boilers, EU-11, EU-13, and EU- 18 or replace the boilers with one or more new boilers.*
- *Determine whether to complete the NO_x reduction project or replace the boilers by July 31, 2022 and meet with DEQ by December 31, 2022 to discuss the technical details of the selected project to determine needed permitting.*

If Permittee chooses to complete a NO_x reduction project:

- *By July 31, 2026, Permittee shall install low NO_x burners and flue gas recirculation on EU-11, EU-13, and EU-18 in order to achieve an emission rate no greater than 0.09 lb/MMBtu on a seven day rolling basis.*
- *As expeditiously as practicable, but not later than July 31, 2026, install a CEMS to measure the emissions of NO_x from EU-11, EU-13, and EU-18.*

If Permittee chooses to replace EU-11, EU-13, and EU-18:

- *PSELs for Round 2 regional haze pollutants incorporated in the Permit for the replacement shall be no more than the potential to emit of the replacement, or a Q of 889 tons per year of NO_x, 437 tons per year of SO_2, and 311 tons per year of PM_{10}, whichever is lower.*
- *Complete the replacement of the EU-11, EU-13, and EU-18 with new technology no later than July 31, 2031.*

NPS Comments:

Based upon information submitted by GP, actual power boiler NO_x emissions are 436 tpy and the proposed 0.09 lb/mmBtu NO_x emission rate represents 64% reduction (280 tpy). As shown below, addition of SCR is highly cost-effective and would reduce actual emissions by 394 tpy (see Tables 4–6).

Table 4. GP-Toledo Power Boiler #1 (EU-13)

SCR	**Company/Consultant Estimates**		**NPS Estimates**	
Unit	#1 Pwr Blr (PSEL)	#1 Pwr Blr (actuals)	#1 Pwr Blr (PSEL)	#1 Pwr Blr (actuals)
Current Emission Rate (lb/mmBtu)	0.271	0.28	0.271	0.28
Current Emissions (tpy)	224	150	223	150
Controlled Emission Rate (lb/mmBtu)	0.0270	0.028	0.027	0.028
Emissions Reduction (tpy)	201	135	200	135
Total Annual Cost	$ 1,736,111	$ 1,713,128	$ 403,086	$ 376,519
Cost-Effectiveness ($/ton)	$ 8,623	$ 12,681	$ 2,012	$ 2,782

Table 5. GP-Toledo Power Boiler #3 (EU-18)

SCR	**Company/Consultant Estimates**		**NPS Air Resources Division Estimates**	
Unit	#3 Pwr Blr (PSEL)	#3 Pwr Blr (actuals)	#3 Pwr Blr (PSEL)	#3 Pwr Blr (actuals)
Current Emission Rate (lb/mmBtu)	0.16	0.164	0.16	0.164
Current Emissions (tpy)	108	76	107	76
Controlled Emission Rate (lb/mmBtu)	0.0160	0.0164	0.016	0.016
Emissions Reduction (tpy)	97	68	97	68
Total Annual Cost	$ 1,314,983	$ 1,296,647	$ 344,165	$ 326,507
Cost-Effectiveness ($/ton)	$ 13,579	$ 19,057	$ 3,560	$ 4,796

Table 6. GP-Toledo Hog Fuel Boiler #4 (EU-11)

SCR	**Company/Consultant Estimates**		**NPS Air Resources Division Estimates**	
Unit	#4 Hog Fuel Blr (PSEL)	#4 Hog Fuel Blr (actuals)	#4 Hog Fuel Blr (PSEL)	#4 Hog Fuel Blr (actuals)
Current Emission Rate (lb/mmBtu)	0.168	0.28	0.168	0.28
Current Emissions (tpy)	218	211	218	212
Controlled Emission Rate (lb/mmBtu)	0.0168	0.0280	0.017	0.028
Emissions Reduction (tpy)	197	190	197	190
Total Annual Cost	$ 2,175,317	$ 2,307,306	$ 551,522	$ 514,046
Cost-Effectiveness ($/ton)	$ 11,067	$ 12,173	$ 2,802	$ 2,699

3.4.2 NPS Results & Conclusions for GP-Toledo

- The safety and health concerns expressed by ODEQ relative to adding SCR to the Power Boiler can be addressed by proper operation and maintenance. The water, wastewater concerns are not relevant to SCR. Electricity and natural gas costs were included in the cost-effectiveness analyses.
- Addition of SCR to the power boilers is much less expensive than estimated by GP and its cost-effectiveness is within the ODEQ threshold under PSEL or actual operating conditions.
- Addition of SCR to these three boilers could reduce NO_x emissions by 495 tons/yr under PSEL conditions or 393 tons/yr under actual conditions. Instead, ODEQ's proposal would reduce the PSEL by 297 tpy and actual emissions by 280 tpy.

3.5 International Paper-Springfield Mill

3.5.1 Summary of NPS IP-Springfield Review

From the draft SIP, ODEQ:

In a letter dated January 21, 2021, DEQ notified International Paper of its preliminary determination that their Springfield facility would likely be required to install SCR on the Power Boiler (EU-150A) and take several actions related to restricting alternative or emergency fuels.

On August 9, 2021, International Paper entered a stipulated agreement and order with DEQ and LRAPA, included in Appendix E. The order requires the following and contains other requirements and provisions:

- *On and after July 31, 2022, the Permittee' s combined assigned PSELs for the Power Boiler, Package Boiler, Lime Kilns and Recovery Furnace for the following pollutants are:237 tons per year for SO_2, as a 12-month rolling average; 962 tons per year for NO_x, as a 12-month rolling average; 177 tons per year for PMl0, as a 12-month rolling average.*
- *the only fuel that it may combust in the Power Boiler and Package Boiler is natural gas, except that it may operate the Power Boiler and Package Boiler on ultra-low sulfur dieselfor no more than 48 hours per year and when needed for natural gas curtailments.*
- *the only fuels that it may combust in the Recovery Furnace are Black Liquor Solids and natural gas, except that it may operate the Recovery Furnace on ultra-low sulfur diesel no more than 48 hours per year and when needed for natural gas curtailment.*
- *the only fuels that it may combust in the Lime Kilns are natural gas, product turpentine and product methanol, except that it may operate the Lime Kilns on ultra-low sulfur diesel no more than 48 hours per year and when needed for natural gas curtailment.*
- *By December 31, 2022, International Paper shall install CEMS and measure the emissions of NO_x from the Power Boiler and use data collected from the CEMS to demonstrate compliance with the NO_x emissions rates*

- *Ensure that the CEMS are certified by DEQ and LRAPA no later than May 31, 2023.*
- *On and after January 31, 2025, International Paper shall meet the following emission limit: a 0.25 lb NO_x/MMBtu on a 7-day rolling average from the Power Boiler.*
- *On and after December 31, 2025, the Permittee's assigned PSEL for the following pollutants and Emission Unit is: 179 tons per year for NO_x, as a 12-month rolling average for the Power Boiler.*

NPS Comments:

We recommend that ODEQ document its rationale for modifying its initial proposal to require SCR on the Power Boiler. Information provided by IP and its consultant indicate that actual annual NO_x emissions from the Power Boiler are 140 ton/yr @ 0.22 lb/mmBtu and its PSEL is 873.74 ton/yr. The ODEQ proposal may allow short-term NO_x emissions to increase while 12-month rolling average emissions would decrease by 39 tons.

IP overestimated capital and operating costs of applying SCR to the Power Boiler and the Package Boiler. The resulting Total Annual Cost of $2.9 million for the Power Boiler (actuals) contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unsupported retrofit factor. A 4.75% interest rate was used instead of the current bank prime rate = 3.25% as recommended by the CCM. Operating costs were overestimated due to over-riding of the “Total operating time” and “Total NO_x removed per year” parameters.[3] Reagent costs were overestimated by more than an order of magnitude. We request more information explaining the need to reheat the SCR inlet gas stream as we did not include reheat costs in our analysis. IP’s estimated cost-effectiveness is $22,924/ton. We estimate a Total Annual Cost of $0.9 million = $6,971/ton for addition of SCR to remove 127 ton/yr of NO_x.

We request the same additional information for the Power Boiler and the Package Boiler. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions. The cost-effectiveness of adding SCR falls below the ODEQ threshold of $10,000/ton for the PSEL cases for both boilers, and for the Power Boiler under actual conditions. The cost effectiveness of adding SCR for the Package Boiler clearly exceeds the ODEQ threshold under actual conditions (see Tables 7-8).

3 IP overestimated the operating costs of SCR when it substituted values for “Total operating time for the SCR (top)” and “Total NO_x removed per year” for the values calculated by the CCM “Design Parameters” spreadsheets. For example, for the Power Boiler (actuals), IP’s workbook calculated the Total System Capacity Factor = 0.268 but over-rode that result by entering 8,424 hours for Total operating time for the SCR instead of the value of 2,348 hours that would have been calculated by the spreadsheet. As a result, the workbook calculates annual operating costs as if the SCR were operating at maximum capacity 8,424 hours/yr instead of 2,348 hours. This error was compounded by over-riding the calculation of “Total NO_x removed per year” to reflect 90% removed from the 2017 actual emissions (90% * 140 tpy) instead of 90% removed from the emissions (504 tpy) that would have resulted from the 8,424 hours of operation (90% * 504 tpy). Instead, we adjusted “estimated actual annual fuel consumption” to yield the uncontrolled emissions specified.

Table 7. IP-Springfield Power Boiler (EU-150A)

SCR	Company/Consultant Estimates		NPS Estimates	
Unit	IP Springfield PB (PSEL)	IP Springfield PB (actuals)	IP Springfield PB (PSEL)	IP Springfield PB (actuals)
Current Emission Rate (lb/mmBtu)	0.46	0.22	0.46	0.22
Current Emissions (tpy)	874	140	874	141
Controlled Emission Rate (lb/mmBtu)	0.046	0.022	0.046	0.022
Emissions Reduction (tpy)	786	126	786	127
Total Annual Cost	$ 3,621,820	$ 2,895,491	$ 321,562	$ 160,145
Cost-Effectiveness ($/ton)	$ 4,606	$ 22,924	$ 1,122	$ 6,971

Table 8. IP-Springfield Package Boiler

SCR	Company/Consultant Estimates		NPS Estimates	
Unit	IP Springfield PkgBlr (PSEL)	IP Springfield PkgBlr (actuals)	IP Springfield PkgBlr (PSEL)	IP Springfield PkgBlr (actuals)
Current Emission Rate (lb/mmBtu)	0.20	0.07	0.2	0.07
Current Emissions (tpy)	298	1	298	1
Controlled Emission Rate (lb/mmBtu)	0.020	0.007	0.020	0.007
Emissions Reduction (tpy)	268	1	268	1
Total Annual Cost	$ 2,130,423	$ 825,603	$ 882,460	$ 882,460
Cost-Effectiveness ($/ton)	$ 7,948	$ 655,241	$ 3,292	$ 698,725

3.5.2 NPS Results & Conclusions for **IP-Springfield**

- Addition of SCR to the Power Boiler and Package Boiler is much less expensive than the calculations estimated by IP, and its cost-effectiveness is within the ODEQ threshold under PSEL operating conditions.
- Addition of SCR to the Power Boiler is much less expensive than estimated by IP, and its cost-effectiveness is within the ODEQ threshold under actual operating conditions.
- Addition of SCR to the Package Boiler would exceed the ODEQ threshold under actual operating conditions.
- Addition of SCR to the Power Boiler could reduce NO_x emissions by 1,054 tons/yr under PSEL conditions or 127 tons/yr under actual conditions; this would represent an additional 88 ton/yr of actual NO_x reduction compared to the ODEQ proposal.

3.6 Cascade Pacific Pulp Halsey Pulp Mill

3.6.1 Summary of NPS Cascade Pacific Pulp Halsey Pulp Mill Review

From the draft SIP, ODEQ:

In a letter dated January 21, 2021, ODEQ notified CPP of its preliminary determination that their Halsey facility would likely be required to install LNB/Flue Gas Recirculation on their Power boiler #1, and switch to Ultra Low Sulfur Diesel instead of #6 fuel oil as an emergency backup fuel on site.

On August 9, 2021, Cascade Pacific entered a stipulated agreement and order with DEQ, included in Appendix E, that requires the following and contains other requirements and provisions:

- *The permittee not combust fuel oil #6 at any emission unit in the facility by June 30, 2024.*
- *By January 31, 2022, conduct source testing for NO_x at Power Boiler #1.*
- *By December 31, 2022, finalize design of low NO_x burner to be installed on Power Boiler #1, with objective to achieve 33% reduction is NO_x emissions.*
- *By December 31, 2023, construct and install the low NO_x burner at Power Boiler #1.*
- *By June 30, 2024, submit a report to DEQ with analysis of source test data and a proposal for revised PSELs, to be incorporated into the permittees' permit by modification or at next renewal.*

NPS Comments:

ODEQ's proposed 33% NO_x reduction is not enforceable and is less than the 64% NO_x reduction evaluated by Cascade Pacific Pulp for Low-NO_x Burners. Based upon information submitted by CPP, actual Power Boiler #1 NO_x emissions are 53 tpy (@ 0.22 lb/mmBtu) and the proposed 33% reduction would reduce emissions by 18 ton/yr. Current NO_x emissions from Power Boiler #2 are 6 ton/yr and were not addressed.

CPP has overestimated capital and operating costs of applying SCR to the power boilers (PB#1 & #2). The resulting Total Annual Cost of $1.8 million for PB#1 contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unsupported retrofit factor. Operating costs were overestimated by more than a factor of two due to over-riding of the "Total operating time" and "Total NO_x removed per year" parameters.[4] Reagent costs were overestimated by more than an order of magnitude. Finally, an explanation is needed

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4 CPP also overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR (top)" and "Total NO_x removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the PB#1 (actuals), the workbook correctly calculated the Total System Capacity Factor = 0.232 but over-rode that result by entering 8,622 hours for Total operating time for the SCR instead of the value of 2,032 hours that would have been calculated by the spreadsheet. CPP then allowed the workbook to calculate annual operating costs as if the SCR were operating 8,622 hours instead of 2,032 hours. This error was compounded by over-riding by also over-riding the calculation of "Total NO_x removed per year." Instead, we adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified.

to understand the necessity of reheating the SCR inlet gas stream. We did not include reheat costs in our analysis. CPP's estimated cost-effectiveness is $38,292/ton. We estimated a Total Annual Cost of $0.4 million = $8,276/ton for addition of SCR to remove 48 ton/yr of NO_x. The same issues apply to PB#1 at PSEL conditions as well as PB#2.

We applied the SCR CCM workbook to PB#1 & #2 for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the ODEQ threshold of $10,000/ton for the PSEL cases for both boilers. Addition of SCR to PB#1 under actual conditions is below the ODEQ threshold. The cost effectiveness of adding SCR for PB#2 clearly exceeds the ODEQ threshold under actual conditions (see Tables 9-10).

Table 9. CPP-Halsey Power Boiler #1

SCR	**Company/Consultant Analysis**		**NPS Analysis**	
Unit	#1 PB (PSEL)	#1 PB (actual)	#1 PB (PSEL)	#1 PB (actual)
Current Emission Rate (lb/mmBtu)	0.28	0.22	0.276	0.221
Current Emissions (tpy)	133	53	134	54
Controlled Emission Rate (lb/mmBtu)	0.026	0.022	0.028	0.022
Emissions Reduction (tpy)	119	48	121	48
Total Annual Cost	$ 1,911,460	$ 1,826,543	$ 425,353	$ 400,430
Cost-Effectiveness ($/ton)	$ 16,029	$ 38,292	$ 3,523	$ 8,276

Table 10. CPP-Halsey Power Boiler #2

SCR	Company/Consultant Analysis		NPS Analysis	
Unit	#2 PB (PSEL)	#2 PB (actual)	#2 PB (PSEL)	#2 PB (actual)
Current Emission Rate (lb/mmBtu)	0.28	0.18	0.28	0.181
Current Emissions (tpy)	75	6	76	6
Controlled Emission Rate (lb/mmBtu)	0.028	0.018	0.028	0.018
Emissions Reduction (tpy)	68	5	68	5
Total Annual Cost	$1,916,103	$1,028,580	$ 404,952	$ 363,869
Cost-Effectiveness ($/ton)	$ 28,349	$ 204,083	$ 5,926	$ 66,534

3.6.2 NPS Results & Conclusions for CPP-Halsey

- The cost-effectiveness of adding SCR is within the ODEQ threshold of $10,000/ton for the PSEL cases for both boilers.
- Addition of SCR to PB#1 under actual conditions is within the ODEQ threshold. Addition of SCR to this boiler could reduce NO_x emissions by 121 tons/yr under PSEL conditions or 48 tons/yr under actual conditions.
- The cost effectiveness of adding SCR for PB#2 clearly exceeds the ODEQ threshold under actual conditions.

3.7 Gas Transmission Northwest LLC - Compressor Stations 12 & 13

From the draft SIP, Regarding Compressor Station 12, ODEQ:

In a letter dated January 21, 2021, DEQ notified Gas Transmission Northwest of its preliminary determination that Compressor Station #12 would likely be required to install SCR on turbines 12A and 12B. On August 9, 2021, Gas Transmission Northwest entered a stipulated agreement and order with DEQ, included in Appendix E, that requires the following and contains other requirements and provisions:

- *From August 1, 2022, the Permittee's PSELs are 12.7 tons per year for PM10; 317.1 tons per year for* NO_x *and 30.4 tons per year for* SO_2*.*
- *From August 1, 2023, the Permittee's PSELs are: 11.4 tons per year for PM10; 257.2 tons per year for* NO_x *and 21.7 tons per year for* SO_2*.*
- *From August 1, 2024, the Permittee's PSELs are: 10.2 tons per year for PM10; 197.3 tons per year* NO_x *and 13.1 tons per year for* SO_2*.*
- *From August 1, 2025, the Permittee's PSELs are: 8.9 tons per year for PM10; 137.4 tons per year for* NO_x *and 4.4 tons per year for* SO_2*.*

NPS Comment: ODEQ could improve the SIP by describing how actual emissions will be affected by these permit changes. Because Q/d based on recent emissions was low (2.33), we support this approach for addressing potential future emission increases.

From the draft SIP, Regarding Compressor Station 13, ODEQ:

In a letter dated January 21, 2021, DEQ notified Gas Transmission Northwest of its preliminary determination that Compressor Station #13 would likely be required to install SCR on turbines 13C and 13D. On August 9, 2021, DEQ issued a unilateral order, included in Appendix E, that requires the following and contains other requirements and provisions:

- *By July 31, 2023, submit a complete and approvable permit application for the installation and operation of SCR and CEMS on Turbines 13C and 13D;*
- *By July 31, 2024, install a CEMS on Turbines 13C and 13D;*
- *By July 31, 2026, install, maintain and continuously operate SCR on Turbines 13C and 13D with a minimum control efficiency of 90%.*

NPS Comment:

We agree with ODEQ that SCR is the most rigorous, cost-effective NO_x control technology available for Compressor Station 13, which is located 14km from Crater Lake National Park.

3.8 Biomass One, L.P.

The Biomass One White City plant is located in Jackson County, Oregon, approximately 9 miles north of Medford, OR. The facility has two boilers, designated “North Boiler” and “South

Boiler," as well as a small space heater, various storage piles, and additional insignificant sources. The two boilers are essentially identical in design and permitted throughput. The boilers combust wood products as fuel, with natural gas used for startup periods.

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

The North and South boilers were evaluated for NO_x controls in the four-factor analysis. The analysis concluded that addition of SCR could reduce the North boiler's NO_x emissions by 118 tons at a cost of $14,131/ton and the South boiler's NO_x emissions by 149 tons at a cost of $11,100/ton. Some of the parameters used in the four-factor analysis (such as the interest rate and remaining useful life) overestimated costs. Our calculations estimated costs of $7,200/ton NO_x removed for both boilers using the company's analysis methods, which is within the state's threshold of $10,000/ton.

According to the Public Draft SIP, ODEQ notified Biomass One in January 2021 that it had made a preliminary determination that their facility would likely be required to install SCR on both boilers. However, in August DEQ entered into an agreement with Biomass One that does not require SCR installation. The stipulated agreement includes the following provisions:

- Install a Continuous Emission Monitoring System, submit to ODEQ a NO_x optimization plan that describes the permittee's plan to use the CEMS data to operate in a way that minimizes NO_x emissions and implement the plan.
- If a new power purchase agreement is signed, within 180 days of notifying DEQ, Biomass One shall submit a complete application for installation of NO_x reduction technology that includes SCR on the North and South Boiler or demonstrates SCR is technically infeasible or presents other unacceptable energy or non-air quality impacts.
- If SCR is technically infeasible or presents such other unacceptable impacts, the Permittee will propose the best available, technically feasible and achievable NO_x reduction option ODEQ's review and approval.
- Permittee shall install controls approved by ODEQ within 18 months of approval.

NPS Comment:

SCR on the North and South boilers is cost effective and technically feasible. DEQ's response to our comments on Biomass One does not address the technical feasibility or cost effectiveness of SCR, and the discussion in section 3.7.5.14 of the Public Draft SIP does not support the decision not to require it. An alternative emissions reduction plan should provide equivalent emissions reductions, but the agreement does not guarantee that any NO_x emissions reductions will occur in the future. This may result in a lost opportunity to reduce emissions by up to 260 tons per year. We request that DEQ require either installation of SCR or a commensurate level of NO_x emissions reduction within a specified timeframe.

3.9 Roseburg Forest Products Co.

Roseburg Forest Products Co. (RFP) owns and operates a wood products manufacturing complex in Dillard, Oregon that produces lumber, plywood, and particleboard. There are three stoker boilers with auxiliary sanderdust and natural gas burners that combust hogged fuel, sanderdust, natural gas, or a combination thereof to produce steam that is used for cogeneration.

NPS Comment:

According to the Public Draft SIP, ODEQ's preliminary determination was that installation of SNCR would be cost-effective on the three boilers, but ultimately determined to enter into a stipulated agreement and order with RFP instead. The agreement requires the facility to meet specified emissions limits by June 30, 2025 through boiler optimization or by installing SNCR. These alternative methods for NO_x reduction should result in roughly equivalent levels of emissions reductions, and we agree with ODEQ's decision to require these reductions.

Section 3.7.5.15 of the public draft SIP discusses the agreement signed with RFP and shows several of the requirements. We recommend including this additional provision in the discussion in Section 3.7.5.15 for clarity:

> On and after June 30, 2025, Permittee shall meet the following emission limits:
>
> - 0.27 lb NOx/MMBtu on a 7-day rolling average at Boiler 1;
> - 0.26 lb NOx/MMBtu on a 7-day rolling average at Boiler 2;
> - 0.26 lb NOx/MMBtu on a 7-day rolling average at Boiler 6; Or
> - Average of emissions from Boiler 1, Boiler 2, and Boiler 6 of 0.25 lb
> - NOx/MMBtu (7-day rolling average).

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November 1, 2021

VIA E-MAIL

Oregon DEQ
Attn: Karen F. Williams
700 NE Multnomah St., Room 600
Portland, OR 97232-410
RHSIP2021@deq.state.or.us

Re: **Comments on Oregon DEQ's Proposed Regional Haze State Implementation Plan for 2018-2028**

To Whom It May Concern:

Beveridge & Diamond, P.C. submits these comments on behalf of Gas Transmission Northwest LLC ("GTN") regarding the Oregon Department of Environmental Quality's ("DEQ") proposed amendments to the Regional Haze State Implementation Plan ("draft SIP").[1] The proposed rule, subject to Environmental Quality Commission adoption, would amend Oregon's SIP with submittal of the 2018–2028 Regional Haze Plan to the Environmental Protection Agency ("EPA").

Provided below are detailed comments on DEQ's draft SIP.

A. DEQ Should Reconsider Measuring "Reasonable Progress" Via PSEL Reductions.

In Round II of its Regional Haze planning, DEQ sought to capture 80% of Q for major (Title V) sources. When using 2017 Plant Site Emission Limits ("PSELs") to calculate Q, DEQ captured 80% of Q by setting a threshold of Q/d at 5.00. However, calculating Q based on PSELs did not capture the correct 80% of sources for purposes of real-world contributions to visibility impairment in Class I areas.

In its initial screening analysis, DEQ calculated a facility's Q (as part of the Q/d) by using the facility's 2017 PSEL. All facilities with a Q/d over 5.00 were required to conduct a four-factor analysis. However, "[i]f a facility's actual emissions were below the screening

[1] Public comments are due on November 1, 2021. *See* Notice of Proposed Rulemaking at https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/RHSIP2021pnp2.pdf.

threshold and potential emissions above the screening threshold, DEQ provided the source an opportunity to reduce [PSELs] to a point where Q/d would be less than 5.00."[2] If a facility accepted a PSEL reduction to this point, DEQ did not require it to conduct further analysis or implement control technologies

DEQ viewed a Q/d (based on PSELs) as some of "the strongest evidence that emissions from facilities contribute to visibility impairment."[3] But actual emissions, not PSELs, are more accurate both in (1) measuring a source's current contribution to regional haze and (2) evaluating whether reductions will result in "reasonable progress" as required by EPA regulations. *See* 40 C.F.R. § 51.308 (d)(1) ("[T]he State must establish goals . . . that provide for reasonable progress towards achieving natural visibility conditions.").

Actual emissions are a more accurate measure of each facility's contribution to regional haze. A Q/d calculated using actual emissions would allow DEQ to more accurately identify the key contributors to regional haze and prioritize emissions reductions from these sources. Tracking each facility's change in Q/d (based on actuals) over time would allow DEQ to more accurately measure true visibility improvement progress.

Q/ds calculated by using PSELs can be misleading, as certain sources with relatively higher Q/ds are minimal contributors to regional haze because their actual emissions are very low.[4] Measuring emissions by relying on reductions in PSELs may artificially represent "reasonable progress" because a source's actual emissions may not change upon a PSEL reduction.

EPA's guidance does not support using PSELs to calculate Q/d. EPA's 2019 Guidance states that "[a] state may use a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts . . . ."[5] Read in context, "annual emissions" refers to *actual* emissions rather than potential emissions (i.e., PSELs). EPA's preference for using actual emissions, rather than PSELs, is further supported by EPA's July 2021 clarification memorandum.[6]

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[2] DEP'T OF EVNTL. QUALITY, OREGON REGIONAL HAZE STATE IMPLEMENTATION PLAN: FOR THE PERIOD 2018–2028, at 35 (Aug. 27, 2021) (hereinafter OREGON REGIONAL HAZE DRAFT SIP).
[3] *Id.* at 38.
[4] GTN's compressor stations simply need an inflated PSEL to maintain operational flexibility and maintain pipeline compression.
[5] GUIDANCE ON REGIONAL HAZE STATE IMPLEMENTATION PLANS FOR THE SECOND IMPLEMENTATION PERIOD 20 (Aug. 20, 2019) (hereinafter 2019 GUIDANCE).
[6] CLARIFICATIONS REGARDING REGIONAL HAZE STATE IMPLEMENTATION PLANS FOR THE SECOND IMPLEMENTATION PERIOD 12 (July 8, 2021) (noting that an approach is to perform four-factor analyses "using recent historical utilization or production levels as the baseline").

The draft SIP's justification for using PSELs in the Q/d analysis cites the following portion of the 2019 EPA Guidance:

> "If a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its [long term strategy (LTS)] in the SIP. . . . The LTS can be said to include those controls only if the SIP includes emission limits or other measures (with associated averaging periods and other compliance program elements) that effectively require the use of the controls."[7]

Because PSELs *are* already enforceable emissions limits, the 2019 Guidance does not support the proposition that DEQ cites it for.

Lastly, using actual emissions, rather than PSEL, would have imposed no additional costs on DEQ. DEQ had data regarding facilities' actual emissions. DEQ should have used the more accurate metric in evaluating key contributors to regional haze and prioritizing actual emissions reductions at those sources.

B. DEQ's Use of PSEL in Its Screening Analysis Was Inconsistent.

In DEQ's initial screen analysis, DEQ allowed a facility to reduce its PSEL such that if its Q/d was less than 5.00, then the facility would "screen out," and DEQ would not require that the facility conduct a four-factor analysis or implement control technologies. However, certain emission sources, such as GTN's compressor stations, were precluded from reducing their PSELs in order to account for worst-case natural gas demand scenarios as required by the Federal Energy Regulatory Commission ("FERC") certification process. DEQ should clarify whether it evaluated other methods or opportunities for facilities to screen out of the requirement of completing four-factor analyses.

For facilities that did not (or could not) reduce their PSELs, DEQ required they conduct four-factor analyses. After receiving these analyses, DEQ adjusted and evaluated them, and then put each source into one of three "bins."[8]

- Bin 1. Likely cost-effective candidates. Control devices with cost less than $10,000/ton, or those that appear to be technically feasible but for which no cost analysis was provided.

[7] OREGON REGIONAL HAZE DRAFT SIP, at 66 (quoting 2019 GUIDANCE, at 43).
[8] GTN's comments regarding DEQ's methodology for adjusting cost-effective controls are discussed below. *See infra* Section D.

- Bin 2. Retain for further analysis. Control devices with cost more than $10,000/ton but less than $30,000/ton.
- Bin 3. Cost is unlikely to be reasonable.[[9]] Above $30,000/ton.[10]

Aside from allowing PSEL reductions to initially screen out such that a facility's Q/d was below 5.00 (and a four-factor analysis was therefore not required), DEQ never permitted a facility to reduce PSEL as part of its four-factor analysis or in subsequent analysis (e.g., evaluating a control technology's cost effectiveness).

C. DEQ Should Provide Greater Clarity in the "Criteria" It Used to Measure Cost Effectiveness.

DEQ did not provide adequate documentation of its process in creating criteria and evaluating entities' cost-effectiveness analyses. The draft SIP notes that DEQ worked "in consultation with EPA and other states" to develop criteria to assess cost effectiveness.[11] DEQ used these criteria to assess "presumed cost-effectiveness of pollution controls."[12] DEQ also used these criteria to evaluate facilities' cost-effectiveness analyses and additional information that facilities submitted with their cost-effectiveness analyses.[13]

DEQ's vague explanation is insufficient. DEQ should:

(1) Clarify whether it also consulted with EPA at this step;[14]
(2) Clarify what criteria were identified;
(3) Clarify how those criteria were applied;
(4) Clarify what "presumed cost-effectiveness" means, and how "presumed cost-effectiveness" was developed and applied.

D. DEQ Should Provide Greater Clarity on How It "Adjusted" Cost-Effectiveness Analyses.

DEQ adjusted parties' cost-effectiveness analyses, but provided limited to no information regarding how it adjusted these analyses.

[9] The draft SIP states that DEQ did not adjust a facility's analysis "for consistency among emissions units" if a facility's submittal exceeded $30,000/ton for a control technology. OREGON REGIONAL HAZE DRAFT SIP, at 35. DEQ should clarify the analysis it undertook, if any, for these submittals.
[10] *Id.*
[11] *Id.* at 26.
[12] *Id.* at 35.
[13] *Id.* at 26–27.
[14] *Compare id*. at 26 ("EPA and other states"), *with id.* at 35 (only states).

1. *Initial Review*

The draft SIP notes that, after DEQ received facilities' initial cost-effectiveness analyses it adjusted those analyses "for basic factors," listing PSEL, interest rate, and useful life.[15] It is unclear whether PSEL, interest rate, and useful life represents an exhaustive list or whether DEQ adjusted parties' submittals for other factors. However, based upon DEQ records, it appears that adjustments were not so limited and that DEQ staff were given the green light to make "additional adjustments . . . over and above the 'basic adjustments.'"[16] DEQ should clarify the scope of adjustments DEQ staff were permitted to make, ideally by identifying the entire spectrum of cost categories that DEQ staff adjusted.

The draft SIP does not indicate what deference, if any, DEQ gave to parties' facility-specific estimates (e.g., vendor quotes) for certain costs or factors in their cost-effectiveness analyses and in DEQ's adjustment of those costs. EPA's Control Cost Manual identifies facility-specific information as the most accurate type of information when evaluating the cost of controls.[17] DEQ should clarify how it evaluated these facility-specific cost estimates and state whether it developed criteria for evaluating parties' facility-specific information.

2. *Subsequent Review*

After identifying control technologies at seventeen facilities, DEQ required additional cost-effectiveness information from these sources. DEQ then "reviewed the additional cost estimate information and sent facilities letters notifying them of DEQ's decisions about the cost effectiveness of controls."[18]

DEQ should clarify its "review" at this stage. As evidenced between parties' submittals and DEQ's decisions, DEQ also adjusted parties' cost-effectiveness submittals in this second review. DEQ should clarify its process for revising parties' submittals—e.g., whether it developed criteria for revisions and, if so, DEQ should provide information regarding those criteria.

Lastly, DEQ should clarify the level of deference it gave, if any, to parties' facility-specific estimates for certain cost items or factors in this second review. DEQ should also clarify whether it developed criteria for evaluating parties' facility-specific information in this second review.

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[15] *Id*. at 35.
[16] Email from Joe Westersund, DEQ, to Yuki Puram, DEQ (July 13, 2020).
[17] *See, e.g.*, CONTROL COST MANUAL SECTION 1 - CHAPTER 2 - COST ESTIMATION: CONCEPTS AND METHODOLOGY 7-8 (2017), https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[18] OREGON REGIONAL HAZE DRAFT SIP, at 36.

E. DEQ Should Correct Certain Mischaracterizations of GTN in the Draft SIP.

Certain references to GTN in the draft SIP, in comments submitted by the National Park Service ("NPS"), are inconsistent and erroneous. For example, NPS asserts that GTN did not use EPA's most recent Control Cost Manual in analyzing Selective Catalytic Reduction ("SCR") as applied to its compressor stations. Incorrect. GTN relied extensively on the 7th Edition of the Control Cost Manual. For example, the Control Cost Manual states that for industrial application of SCR (i.e., not a large electric generating unit) the useful life is 20 to 25 years.[19] Accordingly, GTN used the Control Cost Manual to estimate the useful life of SCR as applied to its compressor station natural gas turbines. Furthermore, the Control Cost Manual acknowledges the preference for site-specific information for cost estimates. To the extent possible, GTN submitted site-specific information in support of its cost estimates.

NPS makes various other assertions regarding GTN, including that a 75% control efficiency for SCR is low, that GTN inflated administrative costs, and that a 30-year useful life for SCR should be used (see above). Incorrect. GTN correctly applied EPA's Control Cost Manual in submitting its four-factor analysis and in calculating the cost effectiveness of SCR as applied to its turbines.

Ultimately, NPS's comments grossly underestimated the cost per ton of NOx removed at GTN's facilities. Using PSELs, NPS estimated that the cost per ton of NOx removed was $1,833 (Unit 12A), $3,801 (12B), $4,074 (13C), and $3,887 (13D). Using reduced fuel consumption scenarios, NPS estimated that the cost per ton was still less than $10,000/ton. However, NPS did not provide its cost estimates in this scenario.

GTN submitted cost-effectiveness analyses for its compressor station units, analyses consistent with the Control Cost Manual, which showed retrofit application of SCR on these units was not cost effective based on DEQ's $10,000/ton threshold. GTN's cost estimate was based on facility-specific information where possible.

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[19] CONTROL COST MANUAL SECTION 7 - CHAPTER 2 - SELECTIVE CATALYTIC REDUCTION § 2.4.2 (2019), https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

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Thank you for your consideration of these comments. If you or your colleagues have questions about this comment or require additional information, feel free to contact me at (206) 315-4811 or dweber@bdlaw.com.

Regards,

David C. Weber

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November 1, 2021

Oregon Department of Environmental Quality
700 NE Multnomah St., Suite 600
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BY EMAIL TO: RHSIP2021@deq.state.or.us
karen.williams@deq.state.or.us

RE: **Public Comment on Regional Haze State Implementation Plan by Environmental Justice Advocates**

Dear Director Whitman, DEQ staff, and members of the Environmental Quality Commission,

On behalf of the undersigned organizations, we respectfully submit these comments on the aspects of Oregon's Regional Haze State Implementation Plan ("SIP") pertaining to the regulation of stationary sources that collectively contribute 80% of Oregon's regional haze-forming emissions.

Introduction and Background

The EPA's Regional Haze program is aimed at improving air quality in national parks and wilderness areas designated as Class I under the Clean Air Act.[1] By reining in visibility-impairing pollution, the Regional Haze program also delivers important public health protections to neighboring communities.[2]

[1] Oregon is home to a dozen Class I protected public lands for which this program is designed to restore clean and clear skies: Crater Lake National Park, Diamond Peak Wilderness, Eagle Cap Wilderness, Gearhart Mountain Wilderness, Hells Canyon Wilderness, Kalmiopsis Wilderness, Mountain Lakes Wilderness, Mount Hood Wilderness, Mount Jefferson Wilderness, Mount Washington Wilderness, Strawberry Mountain Wilderness, and Three Sisters Wilderness.

[2] While the Regional Haze program implicates major and minor sources of pollution as well as mobile sources and area sources, our comments are focused on the Title V stationary sources that collectively contribute 80% of

Oregon's proposed rules to implement the Regional Haze program gave DEQ powerful tools to reduce pollution. Many of the undersigned organizations submitted comments in support of these strong rules.[3] The Q/d screening mechanism resulted in 32 of Oregon's biggest polluters performing four-factor analyses, and the $10,000 cost-effectiveness threshold laid the groundwork for DEQ to be able to order 17 of these sources to install controls that would have improved visibility and protected public health. DEQ sent these facilities "control letters" reflecting DEQ's decision as to which cost-effective control they would likely be required to install, based on the agency's four-factor analysis.[4]

However, after comments on the Division 223 rules were closed, DEQ fundamentally altered its approach without engaging in any kind of public process and without consulting stakeholders other than the regulated entities. Instead of ordering all 17 facilities to implement the reasonable progress controls identified through four-factor analyses, DEQ inexplicably chose to extend offers that allowed all but one of these facilities to exit the program or comply with the program without investing in the highly effective pollution-reducing technology that DEQ could—and should—have required these facilities to install to meet the state's obligations under the regional haze program.

Ultimately, DEQ only unilaterally ordered ***one*** of the 32 facilities that completed four-factor analyses to install reasonable progress controls. One facility, EVRAZ, voluntarily agreed to implement the reasonable progress control identified in DEQ's control letter. For the other 15 facilities that identified cost-effective controls, DEQ allowed them to voluntarily reduce their Plant Site Emission Limits (PSELs)—the high pollution limits contained in Oregon's air permits—or voluntarily take other less effective emissions-reducing steps instead of installing the reasonable progress controls DEQ indicated it would require them to install based on their four-factor analyses.

Notably, DEQ's consultation with the Federal Land Managers, including National Park Service, happened before DEQ executed these back-room agreements. Given the significance of this change in direction, there is a real question as to whether DEQ has satisfied the requirement to consult with Federal Land Managers no less than 60 days prior to a public hearing or public comment opportunity. See 40 CFR 51.308(i). The purpose of this requirement is to allow Federal Land Managers to offer their recommendations on the proposed strategies to address visibility impairment; consultation that happens before a major, unannounced change in strategy is not meaningful consultation. We agree with the National Parks Service's comments on ten facilities' cost analyses and urge DEQ to adopt and require the reasonable progress controls identified by the Park Service in the revised SIP. *See* SIP at App'x G.

The result is that Oregon's Regional Haze program will not deliver the community and public land-benefitting emissions reductions that the rules should have delivered and that advocates expected.

Oregon's emissions of visibility impairing pollutants (NO2, SO2, and PM). *See* Notice of Rulemaking, https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/RHSIP2021pnp2.pdf at 5 (laying out primary elements of Oregon's long-term strategy).

[3] *See* DEQ, Regional Haze 2021, Staff Report (July 22, 2021), https://www.oregon.gov/deq/EQCdocs/072321_ItemJ_RegionalHaze.pdf at 39 (noting comments from Cully Air Action Team (CAAT), Earthjustice, Friends of the Columbia Gorge, Green Energy Institute (GEI), Oregon Environmental Council (OEC), National Parks Conservation Association (NPCA), Neighbors for Clean Air, Northwest Environmental Defense Center (NEDC), Verde).

[4] The control letters are available on DEQ's website. *See* DEQ, Facilities Conducting Four Factor Analysis, https://www.oregon.gov/deq/aq/Pages/haze-ffa.aspx.

For the 15 facilities that DEQ allowed to exit the program, ordering the facility to install pollution controls identified in the facility's four-factor analysis would have resulted in greater emissions reductions than will be achieved by the back-room agreements. *See infra* § I(B). Indeed, all but one of the off-ramp agreements with defined new PSELs allow facilities to continue emitting at levels ***above*** their 2017 emissions, which DEQ used as a baseline. In other words, those agreements will not result in ***any*** reductions from the baseline emissions level. *Id.*

Nothing in Oregon's rules allows DEQ to offer alternative compliance options that result in less effective emissions reduction measures, and nothing requires the agency to offer alternative compliance options at all. Oregon's newly adopted Regional Haze rules specify that "DEQ may, but is not required to, offer alternative compliance" to sources required to submit a four-factor analysis by entering into "a stipulated agreement and final order" under which a source agrees to either accept PSEL limits to bring the source's emissions below the threshold for inclusion in the Regional Haze program, take other steps to reduce emissions equivalent to the emissions reductions from installation of reasonable progress controls identified in the source's four-factor analysis, or replace their emissions units. OAR 340-223-0110(2).

The only rationale DEQ offered for this choice is that the agency offered these off-ramps to facilities with actual emissions that would exclude them from the program if the threshold for inclusion in the program were based on the facility's actual 2017 emissions rather than their 2017 permitted emissions limits. *See* SIP at 35. This appears to be an after-the-fact attempt to rewrite the rules to change the screening threshold for inclusion in the Regional Haze program from a threshold based on permit limits—a threshold that brought 32 facilities into the program—to one based on actual emissions—a threshold that would have left out 18 of those facilities—without undergoing public scrutiny and comment on this approach. Eight of the facilities to which DEQ offered alternative compliance would still have been included in the program even if the threshold were based on their actual emissions rather than permit limits.[5] DEQ's rationale for this choice simply does not explain DEQ's actions.

Moreover, nothing in the SIP suggests that DEQ analyzed whether the "alternative compliance" agreements that required emissions reduction measures different from the ones identified in DEQ's control letters provide equivalent reductions or studied the impact of these agreements on Oregon's Regional Haze strategy. Nothing in the SIP attempts to justify the off-ramping of 15 facilities by reference to any requirements of the Regional Haze program.

The modeling in Oregon's SIP shows that if DEQ had ordered all 17 facilities that identified cost-effective controls in their four-factor analyses to install those controls, Oregon would be on or below the glidepath for some—but not all—of the Class I areas. *See* SIP at 75. In other words, Oregon's Regional Haze strategy depends on taking steps DEQ has chosen not to take, plus other emissions reductions. By allowing 15 out of 17 facilities with cost-effective controls to satisfy their Regional Haze obligations by taking steps that reduce emissions less than installing reasonable progress controls would, Oregon has already undermined its own compliance strategy.

[5] *See* Table 3-6, SIP at 45 (showing actual Q/d > 5.00 for Owens-Brockway Glass Container, Gilchrist Forest Products, Boise Cascade Wood – Elgin Complex, Georgia Pacific – Wauna Mill, Cascade Pacific Pulp – Halsey Pulp Mill, International Paper – Springfield, Georgia-Pacific – Toledo, Roseburg Forest Products – Dillard); Appendix E (Stipulated Agreements and Final Orders for all eight facilities).

DEQ's decision to allow some of Oregon's largest stationary sources of haze-forming pollution to reduce the overhead in their air permits instead of installing pollution controls that satisfy a four-factor reasonable progress analysis violates the Clean Air Act and federal Regional Haze rules.

It is also an abrogation of Oregon's duty to its environmental justice communities. By allowing 15 facilities to avoid reducing their emissions at all or to take less effective emissions reduction steps, Oregon has prioritized the interests of the regulated entities over the interests of those facilities' neighbors whose health and well-being are threatened by NOx, SO2, and PM and who would have benefitted from more effective controls.

In Section I, we demonstrate that Oregon's decision to offer almost every facility with reasonable progress controls available "alternative compliance" instead of installing those controls undermines Oregon's ability to reduce air pollution and make reasonable progress towards the goal of natural conditions and violates the Regional Haze requirements. Section I(B) contains a table comparing the emissions reductions that would have resulted from ordering facilities to install cost-effective controls identified in their four-factor analyses versus those that will result (if any) from the measures in the "alternative compliance" agreements.

In Section II, we explain that, even assuming that there are circumstances in which it would be permissible under the Regional Haze rules to off-ramp facilities instead of ordering them to install reasonable progress controls, Oregon has failed to adequately justify its decision. Oregon's modeling to demonstrate how the SIP relates to Oregon's reasonable progress goals is based on the assumption that facilities would install and operate the specific controls identified in DEQ's control letters based on the facilities' four-factor analyses. DEQ cannot satisfy the Regional Haze program's requirements without analyzing the effect of these back-room agreements and comparing the emissions reductions from the agreements to the emissions reductions from reasonable progress controls. Oregon has not used an appropriate framework for exempting facilities from the requirement to install reasonable progress controls and instead selected the measures in the alternative agreements that in most cases reflected business as usual.

In Section III, we unpack how DEQ's decision to offer "alternative compliance" to 15 facilities flies in the face of Oregon's commitment to environmental justice. The back-room process through which DEQ entered these agreements, without any community input or oversight, cannot be reconciled with DEQ's definition of environmental justice: "the fair and meaningful involvement" of affected communities. Nor do the substance of these agreements serve communities.

I. OREGON'S DECISION TO EXEMPT STATIONARY SOURCES FROM THE REQUIREMENT TO INSTALL REASONABLE PROGRESS CONTROLS VIOLATES REGIONAL HAZE REQUIREMENTS.

Oregon's proposed SIP fundamentally fails to meet Clean Air Act and Federal Regional Haze Rule requirements because it relies on impermissible backroom agreements that allow some of the largest haze-producing sources in the state to avoid federal regional haze requirements, undercutting the emission reductions necessary for the state to make reasonable progress towards visibility improvement goals.

A. Regional Haze Requirements

The Clean Air Act establishes "as a national goal 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 U.S.C. § 7491(a)(1). To advance this goal, the Clean Air Act and EPA's implementing regulations (the Regional Haze Rule) direct Oregon, and all states, to periodically revise their state implementation plan ("SIP") to make incremental "reasonable progress" toward eliminating human-caused visibility impairment in Class I federal areas by 2064. 40 C.F.R. 51.308(f).

In developing a SIP, a state must:

- Calculate progress to date on improving air quality in Class I areas and the Uniform Rate of Progress;
- Develop a long-term strategy for addressing regional haze by evaluating the four factors under the Clean Air Act four factors to determine what emission limits and other measures are necessary to make reasonable progress towards the visibility goal;
- Conduct regional-scale modeling of projected future emissions under the long-term strategy to establish reasonable progress goals and then compare those goals to the Uniform Rate of Progress line; and
- Adopt a monitoring strategy and other measures to track future progress and ensure compliance.

82 Fed. Reg. 3078, 3091 (Jan. 10, 2017).

The Clean Air Act requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. States may not subsequently reject measures they previously deemed reasonable. *See infra* § I(C). EPA's 2017 Regional Haze Rule Amendments made clear that states must first conduct the required four-factor analysis for its sources, and then use the results from its four-factor analyses and determinations to develop the reasonable progress goals. The key determinant of whether a state is satisfying its Regional Haze obligations is whether a state's strategy is based on the four statutory factors. A state must consider the four factors regardless of where any Class I area is on the glidepath. *See infra* § I(D) (explaining that the Uniform Rate of Progress is not a "safe harbor").

A state's SIP must be supported by a reasoned analysis and include a description of the criteria the state used to determine which sources or groups of sources it evaluated and how the four statutory factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. *See* 42 U.S.C. § 7491(g)(1); 40 C.F.R. 51.308(f)(2)(i). The state must document the technical basis for the SIP, and include that information in the plan when they make it available for public comment.

The long-term strategy is a core component of the SIP operating as means through which a state ensures that its reasonable progress goals will be met. As part of the process for developing the long-term strategy, the Regional Haze Rule explicitly directs states to determine reasonable progress by using the four factors listed in the Clean Air Act—costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source—to analyze control options for identified haze-polluting sources (known as the four-factor analysis). 40 C.F.R. 51.308(f)(2). This analysis is important because it identifies the level of control sources need to achieve for Oregon to make reasonable progress towards the state's visibility goal, which are the emission reduction measures that become part of the state's long-term strategy. *Id*. The Regional Haze Rule is clear that in establishing a long-term strategy for regional haze, states must:

> [E]valuate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment….[I]nclude in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.

40 C.F.R. 51.308(f)(2)(i).

A state's SIP must also meet consultation requirements. The state is required to draft the SIP in consultation with the Federal Land Managers of the Class I national parks and wilderness areas affected by the state's haze-pollution to ensure that it improves air quality in those areas and document how the state addressed comments provided by Federal Land Managers. *See* 40 CFR 51.308.

It is the state's duty to demonstrate that reasonable progress requirements are met. While a state may request information and analysis from regulated sources, and importantly collaborates with its regional planning organization throughout the haze planning process, the state is ultimately accountable for preparing, adopting, and submitting a compliant SIP to EPA.

B. The Backroom Agreements Result in Substantially Less Reduction in Emissions Than Would Be Achieved By Installing Reasonable Progress Controls.

The "alternative compliance" options that DEQ extended to 15 of the 17 facilities that identified cost-effective controls all result in far fewer emissions reductions than would be achieved if those sources were required to install the reasonable progress controls identified in their four-factor analyses. Of the agreements with reduced PSELs, all but one allow sources to continue emitting at levels above their 2017 actual emissions levels, which DEQ used as the baseline for the SIP.[6] In other words, the agreements for the sources with agreements containing defined PSELs will not result in *any emissions reductions*—and could even result in *increased* emissions—from the 2017 baseline DEQ used to develop the SIP.

The following table reflects a comparison between the emissions reductions from each facility's actual 2017 emissions that would result from ordering the 17 facilities to install the reasonable progress controls identified through a four-factor analysis and reflected in DEQ's control letter versus the emissions reductions (if any) that will result from the provisions of their "alternative compliance" agreements.[7]

[6] The following entities accepted "alternative compliance" consisting of reduced PSELs that are still above their 2017 actual emissions: Boise Cascade Wood Products – Elgin, 31-0006; Georgia Pacific – Wauna Mill, 04-0004; Boise Cascade Wood Products – Medford, 15-0004; Gas Transmission Northwest – Compressor Station 12, 09-0084; International Paper – Springfield, 208850; Georgia Pacific – Toledo, 21-0005 (for the option to replace boilers, minimum PSELs SO2 and PM10 are above 2017 emission levels); Northwest Pipeline – Baker Compressor Station, 01-0038; Northwest Pipeline – Oregon City Compressor Station, 03-2729; and Willamette Falls Paper Company, 03-2145. The only entity that accepted reduced PSELs that were actually below its 2017 emissions level was Owens-Brockway, but as explained below, because it is now operating only one of the two furnaces it was operating in 2017, the new, reduced PSELs are unlikely to result in significant actual emissions reductions.

[7] Joe Kordzi, an environmental engineering consultant with three decades of experience at EPA Region 6, performed the technical analysis reflected in these comments. 2017 actual emissions data obtained from Appendix A and Table

The table does not reflect a perfect one to one comparison because of the variability in the conditions contained in the agreements. For example, some of the agreements lack defined PSELs[8] and some contain multiple possible compliance options, such as installing a control device, changing a fuel source, reducing actual emissions by a certain percentage, ceasing operations, or accepting a reduced PSEL, or some combination thereof.[9]

When an "alternative compliance" agreement included PSEL reductions, the new PSELs were subtracted from the facility's 2017 actual emissions baseline to determine if the agreement resulted in any actual reductions. Negative values in the Alternative Compliance NOx Reduction, SO2 Reduction, or PM10 Reduction columns indicate that the agreement allows the facility to emit at levels higher than the 2017 baseline emissions. In these cases, the agreement will not result in real emissions reductions, and could even result in increased emissions relative to 2017.

When an "alternative compliance" agreement specified that permit limits would be reduced multiple times, the Alternative Compliance NOx Reduction, SO2 Reduction, and PM10 Reduction columns of the table reflect the emissions reductions from the final and greatest PSEL reduction.

When an "alternative compliance" agreement included several compliance options, one of which was PSEL reductions, the columns for Alternative Compliance NOx Reduction, SO2 Reduction, and PM10 Reduction reflect reductions from the PSELs rather than the alternatives.

The total reductions listed at the bottom of the table do not reflect all possible reductions from installation of reasonable progress controls or "alternative compliance" agreements because of data limitations.

In the "Installation of Cost-Effective Control from Four-Factor Analysis" columns, the total reductions do not include reductions from Gilchrist Forest Products, 18-0005, because no "control letter" is available for this facility, so it is unclear what reasonable progress control DEQ would have ordered it to install based on the facility's four-factor analysis. The SIP suggests that DEQ indicated it would require Gilchrist to install Selective Noncatalytic Reduction on boilers B-1 and B-2, which the facility did not think would be technically feasible. *See* SIP at 51.

3-2 in SIP; Stipulated Agreements and Final Orders obtained from Appendix E to SIP; control letters obtained from DEQ website, https://www.oregon.gov/deq/aq/Pages/haze-ffa.aspx. The control efficiencies used to determine emission reductions from the emissions baseline are those reflected in the four-factor analyses except with the exception that Selective Catalytic Reduction efficiencies were assumed to be 95% in all cases, which is a conservative estimate for gas-fired boilers, or unless otherwise specified.

[8] The following facilities' agreements lack defined annual PSELs: Boise Cascade Wood Products – Medford, 15-0004 (uses a combined total PSEL instead of definite limits for each individual Regional Haze pollutant); EVRAZ, 26-1865 (requires PSELs to be based on performance testing); Cascade Pacific – Halsey Pulp Mill, 22-3501 (same); Gilchrist Forest Products, 18-0005 (same); Roseburg Forest Products – Dillard, 10-0025 (contains emissions limits based on 7-day rolling averages).

[9] The following facilities' agreements contained multiple compliance options: Northwest Pipeline – Baker Compressor Station, 01-0038; Biomass One, 15-0159; Boise Cascade – Elgin, 31-0006; Georgia Pacific – Toledo, 21-0005; Northwest Pipeline – Oregon City Compressor Station, 03-2729.

In the “Requirements of Alternative Compliance Agreements” columns, the total reductions do not include all potential reductions from facilities where those reductions could not be quantified, which include:

- JELD-WEN, 18-0006—DEQ has not yet executed any agreement with the facility, though the SIP indicates that it intends to do so and will include the agreement in the final version of the SIP to be submitted to EPA.
- Boise Cascade Wood Products, LLC - Elgin Complex, 31-0006— the agreement totals include emissions reductions from the revised SO2 PSELs in the “alternative compliance” provisions, but do not include any reductions from the provisions requiring installation of unspecified combustion controls on Boilers 1 and 2.
- Georgia Pacific - Wauna Mill, 04-0004—the agreement totals include emissions reductions from the revised PSELs in the “alternative compliance” provisions, rather than any reductions from the provisions requiring installation of Low NOx Burners on Paper Machine 5 and Power Boiler 33, which are unknown.
- International Paper – Springfield, 208850—the agreement totals reflect the 2022 reduced PSELs for NOx, PM10 and SO2 for the Power Boiler, Package Boiler, Lime Kilns, and Recovery Furnace, but not the unknown reductions by 2025 from fuel limitations and NOx emission limits for the Power Boiler.
- Roseburg Forest Products – Dillard, 10-0025—the agreement totals do not reflect any reductions from Roseburg Forest Products because the reductions from the gradual reduction of NOx 7-day rolling average emission limits on Boilers 1, 2, 6 could not be quantified and the agreement did not specify a control.
- International Paper – Springfield, 208850—the agreement totals reflect only reductions from initial reduced PSELs and not later fuel limitations and PSEL reductions for Power Boiler, which could not be quantified.

TABLE: Emission Reductions from 2017 Emissions Levels — Comparison of Reductions from Installation of Cost-Effective Controls and Reductions from "Alternative Compliance" Agreements

		INSTALLATION OF COST-EFFECTIVE CONTROL FROM FOUR-FACTOR ANALYSIS (Reductions measured from 2017 actual emissions)				**REQUIREMENTS OF "ALTERNATIVE COMPLIANCE" AGREEMENT** (Reductions measured from 2017 actual emissions)				
Facility ID	**Facility Name**	**Cost-Effective Control Identified in DEQ Control Letter**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Agreement Requirement**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Notes**
26-1876	Owens-Brockway Glass Container Inc.	Ceramic Catalytic Filter on A-Furnace and D-Furnace	356.4	106.1	48.4	Reduce PSELs effective July 31, 2025	266.7	10.1	21.2	
18-0005	Gilchrist Forest Products	No control letter available				Install Electro-Static Precipitator			52.0	Unknown what cost-effective control DEQ would have ordered
31-0006	Boise Cascade Wood Products, LLC - Elgin Complex	Selective Catalytic Reduction on two biomass boilers	119.7			PSEL for SO_2 only of 17.1 tons beginning 7/31/22. Install combustion controls in Boilers 1 and 2 by 12/31/24. If NOx not reduced by 15%, reduce PSEL by 15% by 3/31/26.		-4.1		Unknown what combustion controls would be installed under Agreement or what effect they would have on NOx emissions. Agreement reductions based on SO2 PSEL only.
04-0004	Georgia Pacific - Wauna Mill	Low NOx Burner on Paper Machines 1, 2, 5, 6, 7; Low NOx Burner on No. 21 Lime Kiln; Selective Catalytic Reduction on No. 33 Power Boiler	494.2			Reduce PSEL for NOx, PM10, and SO_2 by 8/31/26; Low NOx Burner on Paper Machine 5 by 12/31/24; Low NOx Burner on Power Boiler 33 by 7/31/26	-375.3	-373.2	-301.2	Unknown what effect Low NOx Burners in agreement will have on actual emissions

		INSTALLATION OF COST-EFFECTIVE CONTROL FROM FOUR-FACTOR ANALYSIS (Reductions measured from 2017 actual emissions)				REQUIREMENTS OF "ALTERNATIVE COMPLIANCE" AGREEMENT (Reductions measured from 2017 actual emissions)				
Facility ID	**Facility Name**	**Cost-Effective Control Identified in DEQ Control Letter**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Agreement Requirement**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Notes**
22-3501	Cascade Pacific Pulp, LLC - Halsey Pulp Mill	End #6 fuel oil; Low NOx Burner/Flue Gas Recirculation on Power Boiler No. 1 with assumed efficiency of 64%	33.9			End #6 fuel oil by facility by 6/30/24 and Low NOx Burner on Power Boiler 1 by 12/31/23 with assumed efficiency of 33% and unspecified future NOx limits	17.5			Unknown what impact eliminating No. 6 fuel oil will have
15-0004	Boise Cascade Wood Products, LLC - Medford	Selective Catalytic Reduction on three boilers	99.8			Unspecified reduction in NOx, PM10, or SO_2 such that Q=302 tons by 8/1/26	-48.3			Assumed PSEL reduction all in the form of NOx reduction
09-0084	Gas Transmission Northwest LLC - Compressor Station 12	Selective Catalytic Reduction on A and B gas turbines	42.2			Reduce PSEL for NOx, PM10 and SO_2 by 8/1/25	-73.8	-1.8	-4.3	
208850	International Paper - Springfield	Selective Catalytic Reduction on Power Boiler	133.0			PSELs for NOx, PM10 and SO_2 for only the Power Boiler, Package Boiler, Lime Kilns, and Recovery Furnace as specified by 7/31/22; fuel limitations and NOx limit and 179 ton NOx PSEL for Power Boiler only by 12/31/25	-238.0	-169.4	4.4	Reductions from agreement based on PSELs; cannot evaluate effect of later fuel limitations and PSEL reductions for Power Boiler

		INSTALLATION OF COST-EFFECTIVE CONTROL FROM FOUR-FACTOR ANALYSIS (Reductions measured from 2017 actual emissions)				REQUIREMENTS OF "ALTERNATIVE COMPLIANCE" AGREEMENT (Reductions measured from 2017 actual emissions)				
Facility ID	**Facility Name**	**Cost-Effective Control Identified in DEQ Control Letter**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Agreement Requirement**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Notes**
21-0005	Georgia-Pacific – Toledo LLC	Selective Noncatalytic Reduction on No. 3 Boiler; Selective Catalytic Reduction for Nos. 1 & 4 Boilers; Low NOx Burner for Nos. 1, 2 & 3 Lime Kilns; Baghouse for chip handling	424.4		24.7	(1) Low NOx Burner and Flue Gas Recirculation on Nos. 1, 3, and 4 Boilers by 7/31/26 or (2) replace by 7/31/31 and meet minimum PSEL	50.1	-420.9	-115.2	Reductions from agreement based on minimum PSEL
01-0038	Northwest Pipeline LLC - Baker Compressor Station	Low Emission Control on C1, C2, C3, and C4 RICEs (80% control)	125.7			(1) PSEL for NOx, PM10 and SO_2 by 8/1/26 or (2) replace RICEs with Q of replaced RICEs ≤ 201 (total PSEL not specified)	-34.5	-0.1	-3.0	Reductions from agreement based on minimum PSEL
03-2729	Northwest Pipeline LLC - Oregon City Compressor Station	Low Emission Control on EU1 RICEs 1 & 2 (80% control)	123.2			Replace EU1 RICEs 1 & 2 and meet NSPS; PSEL of replaced RICEs $\leq$ 219 (total PSEL not specified)	-65.0			Agreement NOx reduction based on 2017 actuals for the two RICEs minus the Agreement PSEL for replaced RICEs of 219
15-0159	Biomass One, L.P.	Selective Catalytic Reduction on North and South Boilers	282.2			(1) Cease operation by 1/1/27 or (2) install Selective Catalytic Reduction on North and South Boilers or (3) demo SCR is infeasible. If (3) then unspecified NOx controls.				Cannot determine Agreement NOx reductions due to options and unspecified potential NOx controls if SCR infeasible

		INSTALLATION OF COST-EFFECTIVE CONTROL FROM FOUR-FACTOR ANALYSIS (Reductions measured from 2017 actual emissions)				REQUIREMENTS OF "ALTERNATIVE COMPLIANCE" AGREEMENT (Reductions measured from 2017 actual emissions)				
Facility ID	**Facility Name**	**Cost-Effective Control Identified in DEQ Control Letter**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Agreement Requirement**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Notes**
10-0025	Roseburg Forest Products - Dillard	SNCR on Boilers 1, 2 and 6 (25% control)	236.6			Gradual reduction of NOx 7-day rolling average emission limits on Boilers 1, 2, 6 from 1/31/23–6/30/25				Effect of agreement on NOx totals cannot be determined because agreement does not require a particular control; 7-day average emission limits in agreement could be achievable through SNCR or combustion controls
18-0006	JELD-WEN	Selective Noncatalytic Reduction on wood-fired boiler	20.1							No agreement executed at time of technical analysis
03-2145	Willamette Falls Paper Company	Low NOx Burner on Boilers 1 & 2	70.7			PSEL for NOx, PM10, and SO_2 by 8/1/22; Boilers 1, 2, and 3 only burn gas and ULSD for 48 hrs/yr	-53.9	-2.3	-5.0	Reductions from agreement based on minimum PSEL
Total reductions[10]			**2,562.1**	**106.1**	**73.1**		**-554.5**	**-961.7**	**-351.1**	

[10] Total reductions do not reflect all possible reductions from installation of reasonable progress controls or "alternative compliance" agreements. Please see preceding explanation of limitations on calculation of total reductions.

This comparison between the emissions reductions from installation of cost-effective controls identified in facilities' four-factor analyses and the reductions expected from the measures in the "alternative compliance" agreement demonstrates several things:

- In almost every instance, a facility's "alternative compliance" agreement resulted in demonstrably lower emission reductions than would have been achieved by installing controls identified in the facility's four-factor analysis. This was true even in some cases where the four-factor analysis and agreement called for the same control. For example, for Cascade Pacific Pulp – Halsey Pulp Mill, both the four-factor analysis and agreement called for a Low NOx Burner on Boiler 1 and elimination of number 6 fuel oil. However, the four-factor analysis evaluated the Low NOx Burner at an efficiency of 64% while the agreement required an efficiency of 33%.

- With the exception of Owens-Brockway, in every case in which the agreement contained a reduced PSEL or offered a reduced PSEL as an optional alternative to installing a particular control, subtracting the new PSEL from the facility's actual 2017 baseline emissions resulted in negative values. This means the agreement will not only result in no real emissions reductions, but also allows the emissions to increase over the 2017 baseline value.

- The Owens-Brockway facility merits particular attention. While the reduced PSELs in the facility's "alternative compliance" agreement appear at first glance to represent real emission reductions, those reductions are based on a 2017 baseline, when the facility was operating two glass furnaces—Furnace A and Furnace D. Earlier this year in connection with an enforcement action, DEQ ordered Owens-Brockway to retire Furnace A, a condition which is reiterated in the "alternative compliance" agreement. In its Regional Haze control letter, DEQ listed the NOx, SO2, and PM10 PSELs for Furnace D to be 123, 70, and 20 tons, respectively. The Agreement's NOx, SO2, and PM10 PSELs are 137, 108, and 55 tons, respectively. While the Agreement's PSELs apply to the entire facility, not just Furnace D, Furnace D is by far the most significant source of emissions at the facility, and the new PSELs are higher than the PSELs that DEQ indicated previously applied just to Furnace D. Therefore, the PSELs are likely have no impact on the total emissions of the facility. In contrast, the four-factor analysis would have required the installation of ceramic catalytic filters that would have reduced the NOx and SO2 emissions by 90% and the PM10 emissions by 99%. DEQ should have required the installation of a ceramic catalytic filter for Furnace D.

C. <u>DEQ Cannot Use Backroom Agreements to Exempt Sources from the Requirement to Install Reasonable Progress Controls.</u>

Nothing in the Clean Air Act, Regional Haze Rules, or EPA guidance allows Oregon to exempt sources it has identified for reasonable progress controls from installing effective emissions controls that have satisfied the state's thresholds and programmatic requirements. DEQ's backroom agreements allowing sources to avoid installing such controls cuts directly against EPA's explicit guidance that states generally should not reject reasonable controls, regardless of the other emissions-reducing measures that have been taken:

> [A] state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas. More broadly, we do not think a state should rely on these two additional factors to summarily assert that the state has already made

> sufficient progress and, therefore, no sources need to be selected or no new controls are needed regardless of the outcome of four-factor analyses.

EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021), § 5.2, https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation.

By offering sources with cost-effective controls the option to do "alternative compliance" that results in fewer emissions reductions rather than install the reasonable progress control DEQ identified through a four-factor analysis, Oregon has failed to follow this EPA guidance.

D. Oregon Cannot Get on the Glidepath or Achieve Reasonable Progress Goals While Off-Ramping Sources with Cost-Effective Controls Available.

The 2017 Regional Haze Rule requires states to determine the rate of improvement in visibility that would need to be maintained during each implementation period in order to reach natural conditions by 2064 for the 20% most impaired days. The "glidepath," or Uniform Rate of Progress (URP), is the amount of visibility improvement that would be needed to stay on a linear path from the baseline period to natural conditions.

In 2018, eight Class I areas were "just barely" meeting the Uniform Rate of Progress, meaning they were within 5% above the glidepath, while four Class I areas were below the glidepath. *See* SIP at 4. Oregon's projections for 2028 show eight Class I areas more than 5% above the glidepath, no longer meeting the Uniform Rate of Progress, with two more areas within 5% above the glidepath. *See id.* Only Mount Hood Wilderness is projected to be below the glidepath. *See* SIP at 5.

Importantly, however, DEQ's projections for 2028 are based on the assumption that DEQ would order stationary sources to install "controls recommended from DEQ's review of initial four factor analyses submittals[.]" SIP at 75. The projections do not account for the "alternative compliance" option that 15 of these stationary sources received and accepted. In other words, even if Oregon had ordered all 17 facilities that identified cost-effective controls to install reasonable progress controls, Oregon would not be able to achieve its reasonable progress goals for most Class I areas.

Oregon's decision to offer "alternative compliance" to 15 of these facilities further undermines Oregon's ability to stay on the glidepath. The reductions projected for Class I visibility restoration will not occur because DEQ has declined to enter the orders on which those projected reductions are based and instead entered agreements that will result in either fewer reductions or no reductions at all. By relying on this modeling in the SIP after DEQ declined to order these facilities to install reasonable progress controls, the state has misled the public about its ability to achieve the state's reasonable progress goals and stay below the glidepath.

Even if DEQ's decision to make back-room agreements with 15 facilities did not undermine Oregon's ability to get on the glidepath towards natural conditions by 2064 (which it does), the Uniform Rate of Progress is not a "safe harbor" and "states may not subsequently reject control measures that they have already determined are reasonable." 82 Fed. Reg. 3078, 3093. In other words: DEQ's decision to reject reasonable progress controls and instead enter agreements not based on a four-factor analysis violates the Regional Haze Rules ***regardless*** of whether Oregon can still stay on the glidepath.

E. Oregon's Long-Term Strategy Runs Afoul of the Regional Haze Requirements

EPA's recent guidance clarifies the relationship between four-factor analysis, long-term strategy, and reasonable progress goals:

> Reasonable progress towards natural visibility conditions at any particular Class I area is achieved when all contributing states are implementing the measures in their long-term strategies. RPGs are the modeled result of the measures in states' long-term strategies, as well as other measures required under the CAA (that have compliance dates on or before the end of 2028). RPGs cannot be determined before states have conducted their four-factor analyses and determined the control measures that are necessary to make reasonable progress.

EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021), § 3.1, https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation.

Because of DEQ's decision to broadly offer "alternative compliance," DEQ's long-term strategy is fatally flawed and violates the Clean Air Act and Regional Haze requirements. The agency initially used the four factors to identify reasonable progress controls for 17 sources of haze-forming pollution, and sent those sources "control letters" indicating what controls they would likely be required to install based on a four-factor analysis. The SIP includes modeling based on the reductions that would result from the installation of these controls.

But DEQ inexplicably abandoned all reference to the four factors or to reasonable progress when it entered backroom agreements exempting 15 of those sources from the requirement to install the reasonable progress controls that had been identified through the four-factor analyses, and never modeled the impact of these agreements. DEQ's indiscriminate use of "alternative compliance" leaves Oregon unable to satisfy the long-term strategy requirement. Oregon cannot determine the emissions reduction measures necessary to make reasonable progress without conducting the statutorily required four-factor analysis of its emissions reduction strategies. Oregon also cannot demonstrate how the four factors were taken into consideration in selecting these "alternative compliance" measures for inclusion in its long-term strategy because the state did not take these requirements into account.

II. EVEN ASSUMING IT WOULD BE PERMISSIBLE UNDER SOME CIRCUMSTANCES TO OFFER FACILITIES AN OFF-RAMP FROM THE PROGRAM, THE SIP FAILS TO ADEQUATELY JUSTIFY THIS DECISION.

Even assuming the Clean Air Act and Regional Haze Rules permit Oregon to offer "alternative compliance" to facilities that have already undergone a four-factor analysis and identified cost-effective controls, which they do not, Oregon's SIP does not contain adequate analysis and documentation to justify DEQ's decision to offer alternative compliance to each of the off-ramped facilities under the present circumstances.

DEQ claims that it "offered facilities an option when their actual emissions had a screening value (Q/d) of less than the threshold of 5.00, but the screening value was greater than 5.00. Those facilities could lower PSELs and screen out of the FFA process." SIP at 48. However, only half of the facilities to which DEQ offered alternative compliance had actual Q/d below the 5.00 threshold. Owens-Brockway, Gilchrist Forest Products, Boise Cascade Wood Elgin Complex, Georgia Pacific Wauna Mill, Cascade Pacific Halsey Pulp Mill, International Paper Springfield, Georgia-Pacific Toledo, and Roseburg Forest Products Dillard all had actual 2017 emissions equivalent to a Q/d above 5.00, but they nonetheless received offers to enter stipulated agreements and final orders and thereby avoid being ordered to install the cost-effective controls identified in their four-factor analyses.[11]

The SIP contains no evidence that DEQ's decisions to offer alternative compliance to each of the off-ramped facilities were based on four-factor analyses. Nor is there any evidence that the decisions were based on any of the other decision-making frameworks DEQ outlined in the SIP, such as the weight-of-the-evidence framework or framework for evaluating environmental justice. Indeed, there is no evidence that DEQ analyzed the impact of allowing these facilities to screen out of the program or compared the alternative compliance options to reasonable progress controls before entering into these agreements. The SIP consistently describes this decision as being the facilities' choice, rather than DEQ's.[12]

Without analysis to support DEQ's decision to off-ramp facilities where reasonable progress controls were available or analysis of how off-ramping facilities instead of ordering them to install cost-effective controls identified in their four-factor analyses will affect Oregon's progress towards natural visibility, the SIP violates the Regional Haze rules, which require every SIP to contain a description of "how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy." 40 C.F.R. § 51.308(f)(2)(i). DEQ's description of its long-term strategy is cursory, conclusory, and lacking in analysis.[13]

Notably, nothing in SIP reflects any determinations by DEQ that the reduced PSELs or other pollution-controlling operations steps in the Stipulated Agreements and Final Orders would "provide for equivalent reductions to those identified in its review and adjustment of the four-factor analysis." OAR 340-223-0110(2)(b)(C)–(E). Indeed, documenting such a determination would be impossible because the requirements of the stipulated agreements demonstrably do not provide for equivalent emissions reductions to installing the cost-effective controls identified in the four-factor analyses. *See supra* § I(B).

It is notable that DEQ didn't even include the four-factor analyses or control letters for the off-ramped facilities in the SIP. Although the Notice of Rulemaking contains a link to DEQ's website where these documents can be found, their omission in the SIP reflects how divorced these facilities' stipulated agreements are from the assessments reflected in the four-factor analyses and control letters.

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[11] *See* Table 3-6, SIP at 45 (showing actual Q/d > 5 for Owens-Brockway Glass Container, Gilchrist Forest Products, Boise Cascade Wood – Elgin Complex, Georgia Pacific – Wauna Mill, Cascade Pacific Pulp – Halsey Pulp Mill, International Paper – Springfield, Georgia-Pacific – Toledo, Roseburg Forest Products – Dillard); Appendix E (Stipulated Agreements and Final Orders for all eight facilities).

[12] *See, e.g.*, SIP at 48 (referring to "facilities choosing to comply with Regional Haze Round 2 through PSEL reduction"); *id.* at 51 ("Owens-Brockway chose the alternative compliance option to lower PSELs."); *id.* at 52 ("Boise Cascade [Elgin Complex] chose an alternative compliance option"); *id.* at 53 ("Georgia Pacific [Wauna Mill] chose an alternative compliance option"); *id.* at 54 ("Rather than install controls, Boise Cascade [Medford] chose the alternative compliance option"); *id.* at 59 ("Rather than install controls, Jeld-Wen decided to reduce their PSEL so that Q/d < 5.").

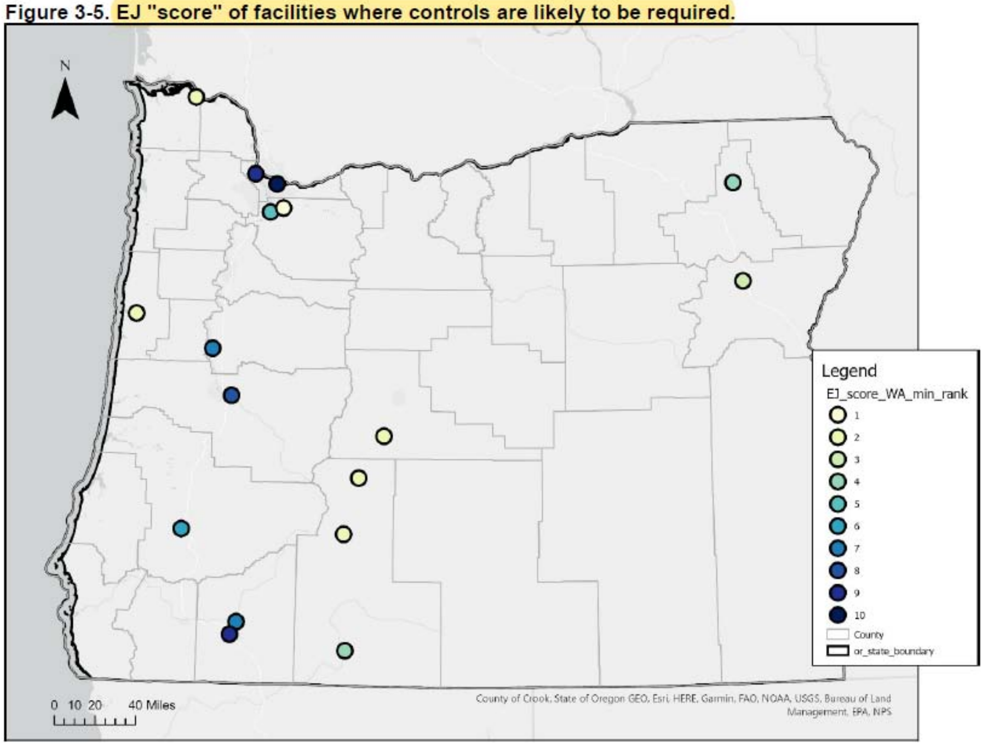
[13] *See* SIP at 66 ("DEQ's long term strategy for stationary sources that DEQ determined in Regional Haze Round 2 are likely to contribute to visibility impairment is to implement the mandatory controls and PSEL reductions described in Section 3.6.").

III. DEQ'S DECISION TO OFF-RAMP FACILITIES INSTEAD OF ORDERING THEM TO INSTALL REASONABLE PROGRESS CONTROLS UNDERMINES OREGON'S COMMITMENT TO ENVIRONMENTAL JUSTICE.

Although Oregon's Regional Haze rules require DEQ to take environmental justice into account when selecting emissions controls for sources, DEQ offered the state's largest polluters an exit plan from the requirement to install emissions controls seemingly without any consideration for Oregon's environmental justice communities—the very communities bearing the brunt of pollution. DEQ defines environmental justice as requiring "the fair and meaningful involvement" of affected communities. *See* SIP 39. And yet, DEQ decided to off-ramp major polluters in overburdened communities without any consultation with those communities. DEQ's actions in extending "alternative compliance" are wholly at odds with its claim that "DEQ believes that emission reductions in Oregon should be targeted towards those communities that experience the greatest burden." SIP at 38.

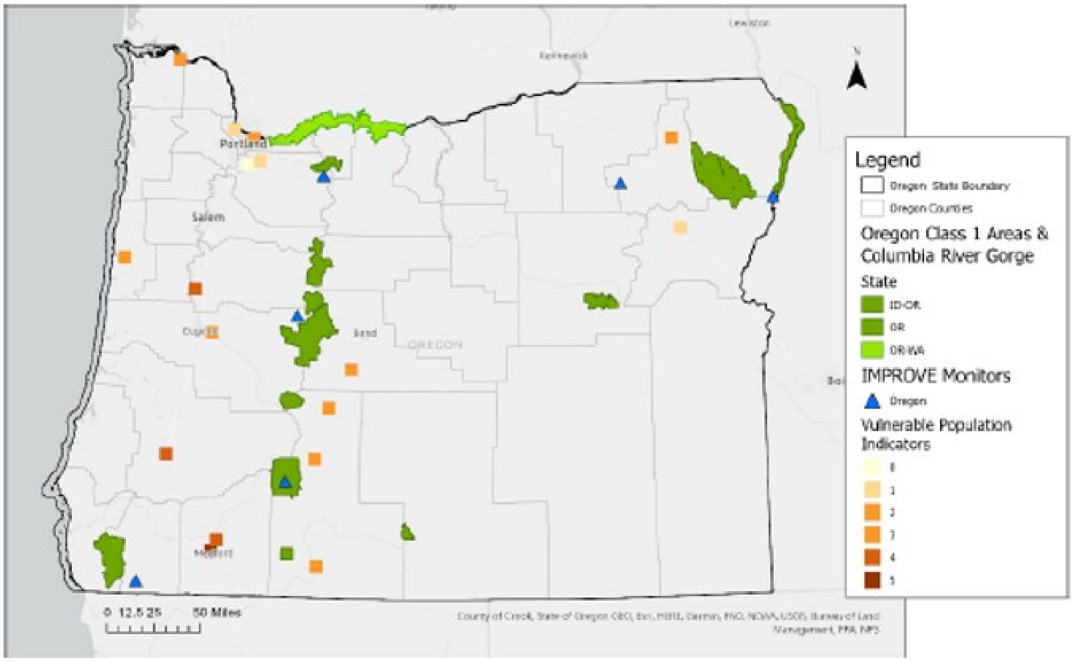
Despite the claim in the SIP that DEQ incorporated environmental justice into its regional haze decisions, nothing in the SIP suggests that DEQ considered environmental justice in making the choice to extend "alternative compliance" to 16 of the 17 facilities with reasonable progress controls. While DEQ carefully established a protocol and analyzed the environmental justice and vulnerable populations "score" of each facility with cost-effective controls identified in its four-factor analysis, it then seemingly ignored this information when making consequential decisions: in place of actual significant reductions in emissions that would be achieved though the implementation of four factor reasonable progress control analyses the agency instead established alternative compliance to these facilities regardless of the environmental justice impacts and the impacts on vulnerable populations.

Figure 3-5. EJ "score" of facilities where controls are likely to be required.

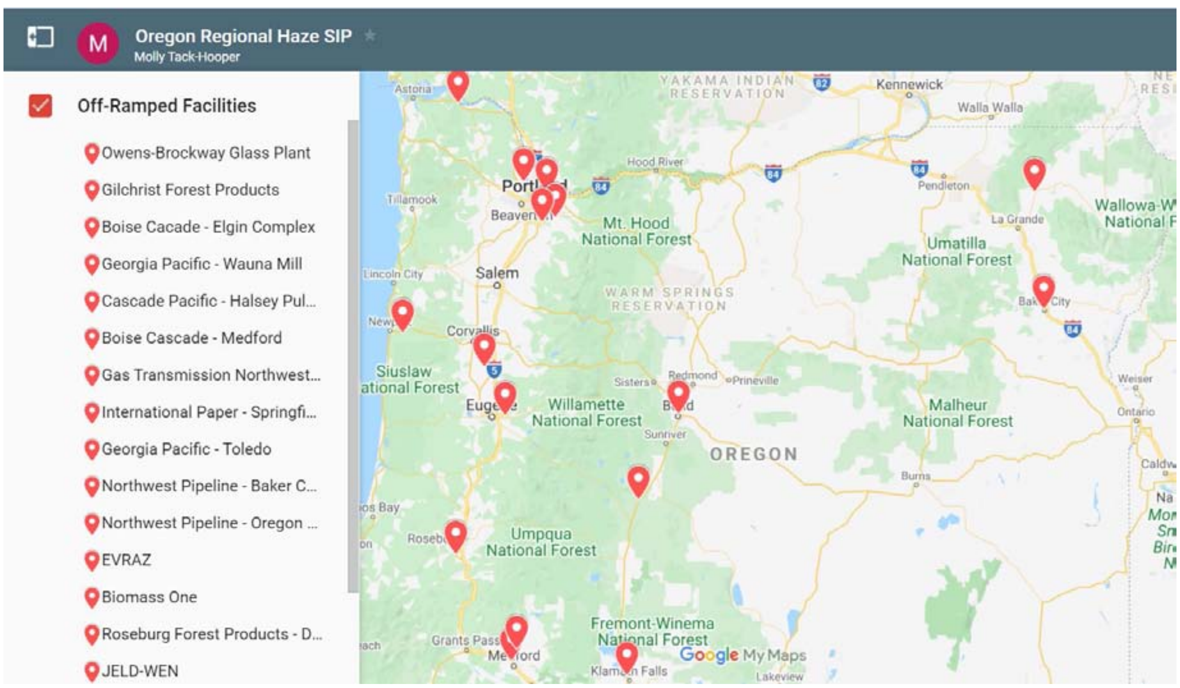


See Table 3-5, SIP at 44.

Figure 3-3. Number of socioeconomic indicators for which the community within 2.5 km of a facility was above the statewide average.



See Figure 3-3, SIP at 40-41.



See Off-Ramped Facilities, Regional Haze Map, https://tinyurl.com/2zmcswuc.

DEQ's backroom agreement with Owens-Brockway underscores the environmental justice costs of allowing some of the state's largest polluters to off-ramp from the Regional Haze Program without requiring actual emission reductions equivalent to what could have been achieved from requiring the facility to install reasonable progress controls.

Owens-Brockway is glass recycling facility that sits between three public schools in Portland's Cully neighborhood, which is home to one of Portland's most diverse census tracts, with more than 50 percent of residents representing communities of color. More than a quarter of Cully residents are low income.[14] According to the most recent National Air Toxics Assessment based on 2014 data, the neighborhoods in closest proximity to the Owens-Brockway plant experience an elevated cancer risk of 40 in one million from air toxics (without accounting for diesel particulate matter and other air toxics for which EPA does not have health-effects data). Given the concentration of environmental health risks in the area and the high percentages of Cully residents that are of color or low-income, this neighborhood, which surrounds the Owens-Brockway facility, is considered an overburdened community.[15]

Although Owens-Brockway voluntarily shut down one of its two furnaces in June 2020 and DEQ ordered the facility to that furnace shut down in June 2021 in connection with an enforcement action, the remaining furnace still exposes neighboring communities to SO2 and NOx—pollutants that can adversely affect lung function and worsen asthma attacks. Modeling recently uncovered that, even when only the sole remaining furnace is running, the Owens-Brockway facility may be causing or contributing to violations of the 1-hour SO2 and 1-hour NOx National Ambient Air Quality Standards designed to protect public health and the environment.[16]

In an enforcement letter to Owens-Brockway, DEQ staff urged Owens-Brockway to voluntarily install a catalytic ceramic filter to address multiple pollutants of concern, noting that it was deemed cost-effective under the Regional Haze program.[17] And in conversations with advocates about their concerns around Owens-Brockway, DEQ staff pointed to Regional Haze program as potential legal lever to order the facility to install a catalytic ceramic filter to address multiple pollutants of concern if the facility would not do so voluntarily. Advocates amplified DEQ's request, asking the facility to voluntarily install pollution controls to address the multiple pollutants of concern.[18]

However, behind closed doors, DEQ did an about-face, and inexplicably offered this facility—which DEQ has described as having a "history of chronic noncompliance" with regulatory requirements[19]—the "alternative compliance" option to reduce the unnecessary overhead in its permit instead of ordering it to install the pollution controls advocates have been asking for, which the facility had declined to install voluntarily.

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[14] To view data, visit https://ejscreen.epa.gov/mapper/; navigate to "Select Location;" "Enter a location or a latitude/longitude;" then enter "97220" and "Get Printable Standard Report." 97220 is the zip code for the Owens-Brockway facility. The process can be repeated for 97218, the Cully zip code.

[15] EPA glossary, https://www.epa.gov/environmentaljustice/ej-2020-glossary.http://npirspublic.ceris.purdue.edu/ppis/product.aspx.

[16] Earthjustice, *Owens-Brockway: An Environmental Justice Problem in Portland* (Sep. 2021), https://earthjustice.org/sites/default/files/files/2021.09.23_portland_air_pollution.pdf.

[17] Oregon DEQ, Letter to Owens-Brockway (June 3, 2021) at 2, https://www.oregon.gov/deq/nr/OwensBrockway2020208NCPO.pdf.

[18] Community Input Regarding Owens-Brockway's CAA Title V Violation (June 28, 2021), https://earthjustice.org/sites/default/files/files/community_ltr_to_owens_re_1mil_fine_-_revised_formatting_002.pdf.

[19] Oregon DEQ, Letter to Owens-Brockway (June 3, 2021), https://www.oregon.gov/deq/nr/OwensBrockway2020208NCPO.pdf.

The new permit emission limits in the "alternative compliance" agreement do not require Owens-Brockway to in any way change its operations, effectively resulting in no actual emission reductions on the ground. And even if the new permit emission limits had required actual reductions in NOx, SO2, and PM10, these limits would not reduce these pollutants in an amount equivalent to the reductions that would result from the installation of a ceramic catalytic filter as should be required for reasonable progress, which would have reduced the facility's NOx and SO2 emissions by 90% and the PM10 emissions by 99%, delivering far greater public health benefits.

Nothing in the SIP explains how offering Owens-Brockway "alternative compliance" instead of ordering it to install reasonable progress controls benefits the environmental justice community where the facility sits—nor could it.[20]

IV. INADEQUATE DOCUMENTATION OF COST ANALYSES

The National Park Service repeatedly notified DEQ of errors in the cost analyses for 10 facilities,[21] including incorrect equipment life, interest rate, retrofit factors, and assorted errors to inputs to SCR and other cost algorithms. *See* SIP at App'x G. Making these corrections often drastically improves the cost-effectiveness of controls at many facilities. It appears that DEQ responded to this feedback by making some recommended corrections to facility cost analyses, including corrections to the interest rate and equipment life, but DEQ did not include any documents reflecting this revised analysis either in the SIP or on DEQ's website. *See id.* With respect to other facilities, it is unclear whether DEQ adequately revised its analysis to correct errors and omissions. Some facilities failed to provide adequate documentation to support their cost analyses, including full vendor information, but nothing in the SIP indicates whether DEQ ever obtained this information to confirm the facilities' cost analyses. For instance, as the National Park Service noted, the cost analyses performed by All4 for the Northwest Pulp & Paper Association erroneously assumed a retrofit factor of 1.5 for every wood waste boiler it evaluated in Oregon, the effect of which is to artificially increase the capital cost by 50%. *E.g.*, SIP at 93. There is no record that DEQ made these corrections.

Omitting complete cost analysis documentation from the SIP violates the requirement in the 2017 Regional Haze rules to "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I area it affects" including the "cost and engineering information on which they are relying to evaluate the costs of compliance, the time necessary for compliance, the energy and non-air quality impacts of compliance and the remaining useful lives of sources." 82 Fed. Reg. 3078-01, 3096 (Jan. 10, 2017). EPA has been explicit that "every source-

[20] We understand that DEQ and Owens-Brockway reached an agreement to settle Owens-Brockway's enforcement action, and that the agreement requires Owens-Brockway to install unspecified controls to reduce PM by 95% by June 30, 2022. *See* DEQ, DEQ reaches agreement with Owens-Brockway: install pollution controls or shut down (Oct. 22, 2021), https://www.oregon.gov/newsroom/Pages/NewsDetail.aspx?newsid=64500. The fact that DEQ eventually used legal authority outside of the Regional Haze program to require the facility to install controls to address some of the facility's pollutants of concern does not change the fact that DEQ should have used its Regional Haze power to that end, and violated the Regional Haze rules by failing to do so. Ordering Owens-Brockway to install a ceramic catalytic filter would not have precluded DEQ from imposing any of the terms in the subsequent enforcement order.

[21] Boise Cascade – Elgin, Boise Cascade – Medford, Georgia Pacific – Toledo, Georgia Pacific – Wauna Mill, Cascade Pacific Pulp – Halsey Pulp Mill, International Paper – Springfield, Gas Transmission Northwest – Compressor Station 12, Gas Transmission Northwest – Compressor Station 13, Biomass One, and Roseburg Forest Products – Dillard.

specific cost estimate used to support an analysis of control measures must be documented in the SIP." EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, (Aug. 20, 2019), § 4(c) at 32, https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Conclusion

For all of the foregoing reasons, we urge DEQ and EQC to revise Oregon's State Implementation Plan. The proposed Plan violates federal law, and will not achieve the emissions reductions necessary to protect visibility in Oregon's Class I areas. The proposed SIP misses the opportunity to protect the health of environmental justice communities in Oregon and evades the Regional Haze requirements that obligate the state to undertake actions in keeping with this objective.

To comply with the Regional Haze rules, DEQ must vacate its "alternative compliance" agreements, which are plainly contrary to the requirements of the Clean Air Act and Regional Haze rules and instead require these facilities to install and operate the most effective reasonable progress controls. Oregon's SIP must demonstrate that DEQ selected and ordered reasonable progress controls for 17 facilities based on a proper four-factor analysis, taking into account environmental justice, and that any orders or agreements deliver emissions reductions at least equivalent to those that would be obtained through the installation of the reasonable progress controls identified in DEQ's control letters.

Sincerely,

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November 1, 2021

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RE: Regional Haze: 2018-2028 State Implementation Plan Comments by Environmental and Community Advocates- Woodburning

Dear Ms. Williams—

Thank you for your work on Oregon's regional haze program. On behalf of the undersigned groups and Multnomah County, we respectfully submit these comments. As to the industrial facilities and their impacts on Class I areas, we incorporate by reference the comments authored by Earthjustice, National Park Conservation Association and others submitted on November 1, 2021. Our comments here are intended to provide a specific focus on the Department of Environmental Quality (DEQ)'s draft State Implementation Plan (SIP) and its address of prescribed burning and residential biomass/woodsmoke which are not addressed in the other written coalition comments.

A. Residential Biomass

While we are excited that this is recognized as a source of emissions, the current draft SIP is insufficient in its proposed rules to reduce emissions from biomass burning/residential woodsmoke. Residential wood smoke may have a particularly pronounced effect in the Columbia River Gorge National Scenic Area due to geography, residential land use in the george, and proximity to population centers where residential wood combustion is common. Section **4.6.2 "Residential Wood Heating" of the SIP merely** states:

> "Oregon's HeatSmart program reduces emissions from residential wood combustion by requiring uncertified stoves to be removed at the time of home sales for the whole state. In addition, community grants authorized by the Oregon Legislature and administered by DEQ pay for wood stove changeouts to natural gas or electric-powered home heating devices in communities for which fine particulate matter pollution has been identified as a major source of wintertime air pollution. DEQ expects to continue to receive

> Legislative funding for woodsmoke reduction work in the coming years, although cannot count on a specific level of support."[1]

The purpose of the Regional Haze Program is to improve visibility in Class I wilderness areas with the goal to attain natural visibility conditions by 2064.[2] While the Haze program is intended to address visibility, visibility problems are caused by the same air pollution that causes deadly health impacts- such as particulate matter, nitrogen oxides and sulfur oxides. SIPs must include federally enforceable rules for sources to reduce emissions of haze-forming pollutants, and must address each source or source category separately. Specifically, Section 51.308(f)(2)(i) of the Regional Haze Rule (40 CFR § 51.308) requires a SIP to include a description of the criteria the state has used to determine the sources or groups of sources it evaluates for potential controls.[3] A state opting to select a set of sources must make "reasonable progress towards natural visibility" which can also be based on the long-term strategy for regional haze.[4] Amongst the 5 factors for long-term strategy are emissions reductions due to: ongoing air pollution control programs, basic smoke management practices for prescribed fire, and the anticipated 'net effect' on visibility due to projected changes in point, area, and mobile source emissions.[5]

In this case, residential wood burning is both a point/area source and has various local and state level programs to mitigate its emissions. We are disappointed that Section 4.6.2 of the SIP, which covers residential wood burning sources, is so sparse and does not adequately address biomass emissions. To begin, we would like DEQ to recognize the insufficiency of the HeatSmart Program as a main approach to reduce emissions. Numerous peer reviewed scientific studies show that woodstove changeouts that upgrade old stoves to "cleaner" woodstoves (like HeatSmart) do not meaningfully decrease pollution: "An in-depth evaluation of the British Columbia wood stove exchange program published in 2014 noted that 6 years after the program began…there has not yet been a clear reduction in fine particulate matter pollution coming from residential wood stoves in BC."[6] Other studies have concluded that "despite the potential for extensive wood stove exchange programs to reduce outdoor PM2.5 concentrations in wood smoke-impacted communities, we did not find a consistent relationship between stove technology upgrades and indoor air quality improvements in homes where stoves were exchanged."[7]

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[1] Oregon Regional Haze State Implementation Plan (Aug. 27, 2021): Public Notice Draft at p. 70.
[2] https://www.oregon.gov/deq/Regulations/rulemaking/Pages/rhsip2028.aspx.
[3] EPA Regional Haze Guidance (Aug. 20 2019) at p. 9.
[4] 40 CFR 51.308(f)(2)(iv).
A state that brings no sources forward for analysis of control measures
[5] 40 CFR 51.308(f)(2)(iv).
[6] BC Wood Stove Exchange Program Evaluation (2008 to 2014), available at https://www2.gov.bc.ca/assets/gov/environment/air-land-water/air/reports-pub/wsep_evaluation.pdf.
[7] The impact of wood stove technology upgrades on indoor residential air quality (2009), available at https://www.sciencedirect.com/science/article/abs/pii/S1352231009007389.

Smoke created from wood burning can be a significant source of air pollution and haze. In fact, at least one Biomass facility in Oregon (Biomass One, LP), has been determined to impact Class I areas and was required to undergo a four-factor analysis.[8] Burning wood releases the same pollutants as wildfires- including but not limited to Sulfur Dioxide, Nitrogen Dioxide, Particulate Matter (direct and precursor pollutants that can impair visibility)[9] and Carbon Monoxide, which are all criteria pollutants under the Clean Air Act's National Ambient Air Quality Standards (40 CFR part 50). Residential wood burning contributes to approximately 12.8 million pounds of PM 2.5 throughout our state, based on the 2017 EPA emissions inventory.[10] And according to DEQ's 2014 Woodsmoke combustion survey, up to 37% of Oregonians burn wood in their homes.[11] It is estimated that 591,000 homes have a wood burning device. Approximately 150,000 homes have an uncertified wood stove and 212,000 homes have a fireplace.[12] Taken cumulatively, that is a lot of biomass emissions and wood burning near various Class I areas. And that does not even count the outdoor residential and recreational burning that occurs. The current SIP fails to consider the 'net effect' of all indoor and outdoor residential burning on air quality and visibility within a region, nor all ways to mitigate it.

The draft SIP fails to mention the specific DEQ statewide woodstove changeout program which allots specific counties grant amounts to help their residents change out their woodstoves and the existing locally-backed education and woodsmoke curtailment programs in each County. It also fails to mention federal ARPA funding- which has been allotted in the amount of $500,000 for woodsmoke changeouts in Multnomah County for the next biennium. The SIP could be strengthened if it incorporated the recognition of additional grant funding needed to continue woodstove changeouts towards non-biomass devices, other policies mentioned in DEQ's 2016 report to the legislature, and the policy proposals from the Multnomah County 2021 woodsmoke working group- which DEQ participated in. This includes but is not limited to:

- Additional grant funding dedicated to providing woodstove changeouts for heat pumps or other non-biomass burning devices .
- More DEQ funding for locally run woodsmoke curtailment programs and public education programs tailored for their residents. Many of them already exist, and require

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[8] Oregon Regional Haze State Implementation Plan (Aug. 27 2021).
[9] EPA Regional Haze Guidance (Aug. 20 2019) at p. 11, available at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.
[10] https://www.opb.org/news/article/oregon-deq-data-woodstove-air-pollution-wildfires/.
[11] DEQ, 2014 Portland residential wood combustion survey (Jan. 2015) at p. 15., available at https://www.oregon.gov/deq/FilterDocs/WoodburningSurvey.pdf.
[12] *Id.* at p. 20.

daily air quality forecasting, technical assistance, compliance monitoring, and enforcement.[13]

- By increasing state funding, each community could employ a full time or dedicated staff-person to implement such programs.[14] Multnomah County just approved an additional $100,000 to employ an air quality specialist in their Health Department for the next biennium to implement their woodsmoke ordinance.
- Increased statewide education and outreach is needed because increasing awareness of the harms of woodsmoke is essential for emissions reduction.[15] Developing and adequately resourcing a multi-year campaign is needed.
- DEQ should be committing to enhanced coordination with other agencies to focus on air quality from wood burning.
- Incentivizing woodstove change outs for heat pumps or other non-biomass burning devices.
- Tax credits should be a part of DEQ's strategy- perhaps through clean energy initiatives.
- DEQ should complete a statewide woodsmoke combustion inventory which will help establish current baseline source emissions. The last one was conducted in 2014 and was limited to the Portland metro area.
- DEQ should consider a permitting scheme for future commercial businesses who want to use a chiminea, chimney, or woodstove based on air quality concerns.

B. Smoke Management and Prescribed Burning

In order to meaningfully address regional haze, DEQ and Department of Forestry would need to consider the rules that allow burning of biomass debris, forest waste on private and public lands and consider volume restrictions. Agencies should limit all unnecessary pile burning and agricultural burning in Oregon. This means that the education and no-burn alternatives should be encouraged and clarified- not in the next few years as stated in the SIP- but almost immediately.[16] All permitted burning should provide scientifically supported data that shows its efficacy in preventing wildfire or providing ecological benefit (prescribed burning). Burning in lieu of forest, domestic or agricultural clean-up practices such as composting should be minimized and limited.

We realize that woodburning and biomass is only one piece of the puzzle contributing to haze. But we urge you to flesh out your long-term strategy and enforceable rules to mitigate emissions.

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[13] DEQ, Woodsmoke in Oregon: HB 3068 Final Report to the Legislature (Sept. 2016) at p. 11.
[14] *Id.*
[15] *Id.*
[16] SIP at p. 69.

Sincerely,

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