Aug. 27, 2021 Public Notice Draft

Oregon Regional Haze State Implementation Plan

For the period 2018 - 2028

Submitted to: Public Notice

Air Quality Planning

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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.

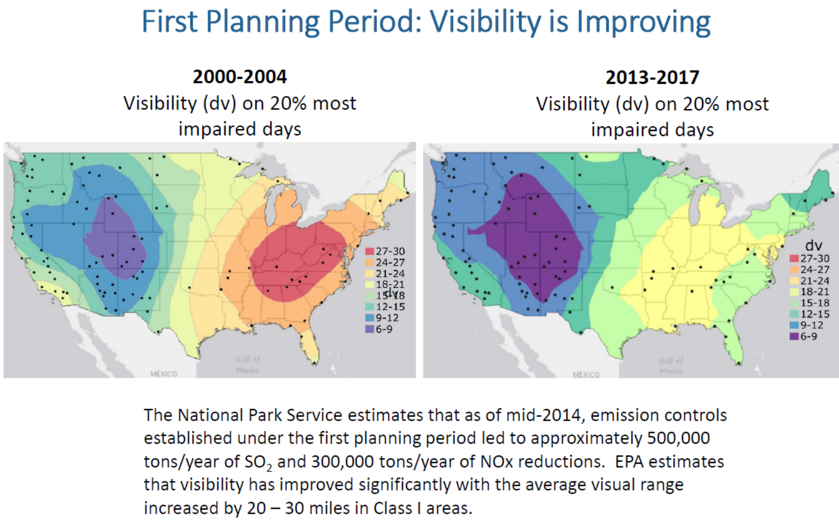
Under the federal 2017 Regional Haze Rule, states are required to develop five-year progress reports showing the latest visibility trends analysis and the current status for meeting reasonable progress milestones since the last submission of the plan. The 2017 progress report summarized changes in monitoring 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 (Figure 1-1).

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)).

[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)

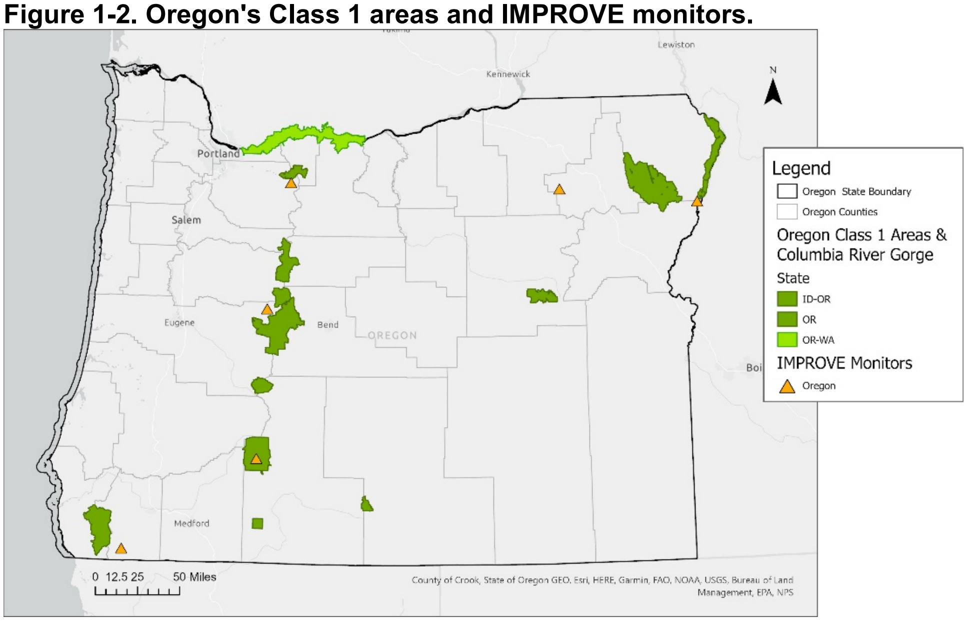
Step or Task	Relevant 2017 Regional Haze Rule Provision(s)
the information, i.e., the tie to the submission of information to the NEI.	
i) Consider source retirement and replacement schedules.	40 CFR 51.308(f)(2)(iv)(C)
j) Set emission limits, averaging periods and monitoring and record keeping requirements.,	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 CFR 51.308(f)(2)(ii)(C)
7) 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)
a) 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)
b) 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 Figure 1-2.

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 Figure 1-2). 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

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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)

degradation on the clearest days over the next 40 years. The goal of 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 NOx 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 2-1, 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	NOx (tons/year)	PM10 (tons/year)	SO2 (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.

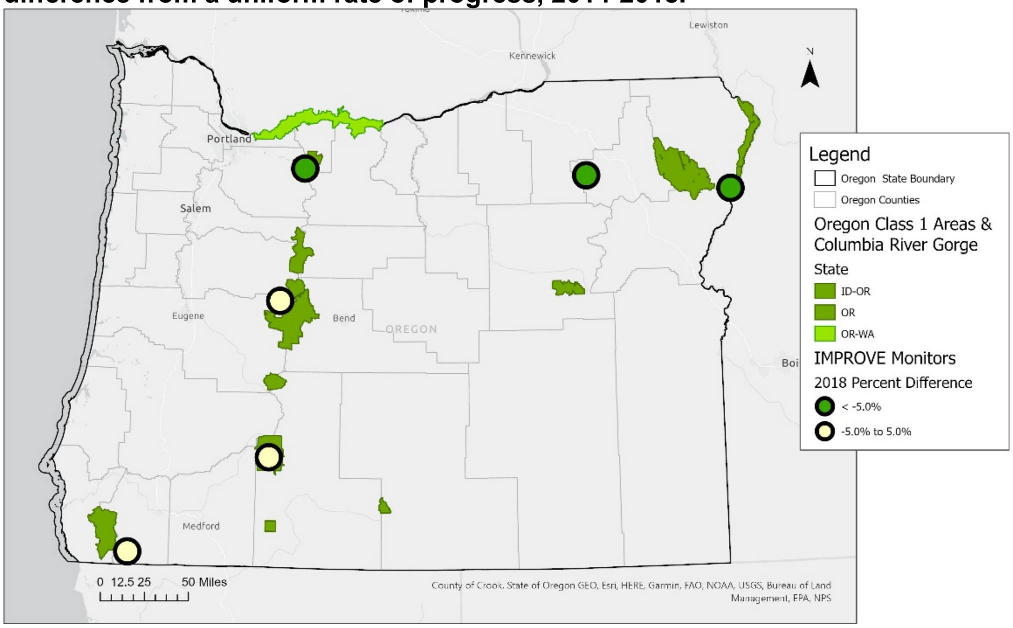
CFR Citation	Progress Report Element	Round 2 Plan Section
40 CFR 51.308 (g)(3)	"For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in 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 2-1 (below) 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).

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.

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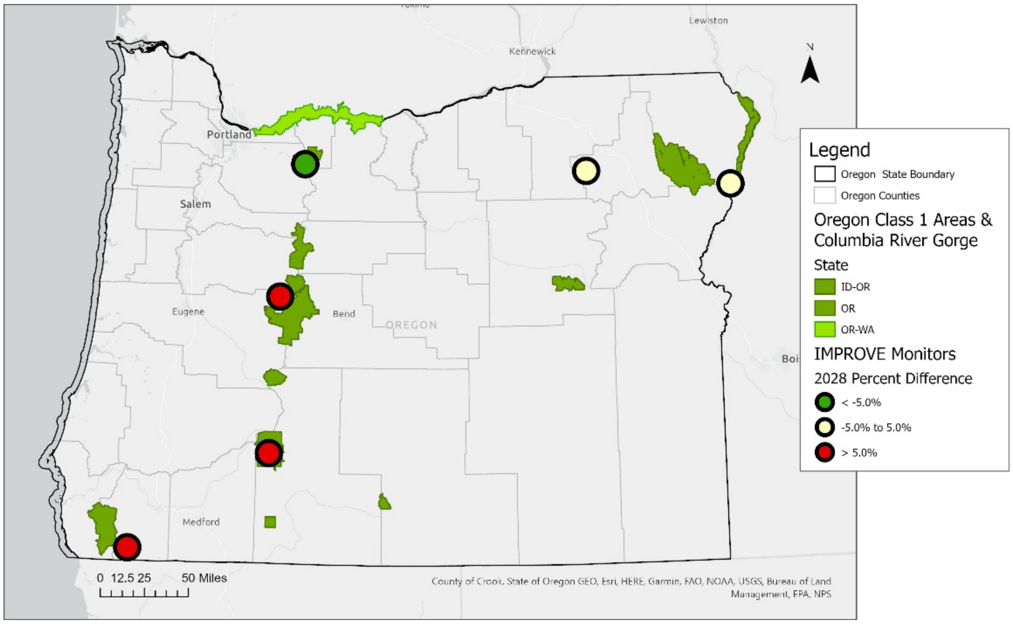
[9] U.S. EPA, 2019, *supra.*

[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)



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 Figure 2-2). 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 2-1 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)
- The difference in deciviews (observed minus expected) of the observed value from the URP for 2018

[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 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 2-2 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 2-2 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 2-3. 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	NOx	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 2-4 through Table 2-6 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 2-4)
- Statewide, the NOx emissions are primarily from mobile sources, at about 80% of the inventory, with another 13% of the inventory coming from fuel combustion (Table 2-5).
- 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 2-6).

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 NOx emissions in tons/year by county, US Anthropogenic, 2017. Source: 2017 National Emissions Inventory.

County	Fires-NOx	FuelComb-NOx	Industrial-NOx	Mobile-NOx	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. Figure 2-3 to Figure 2-8 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.

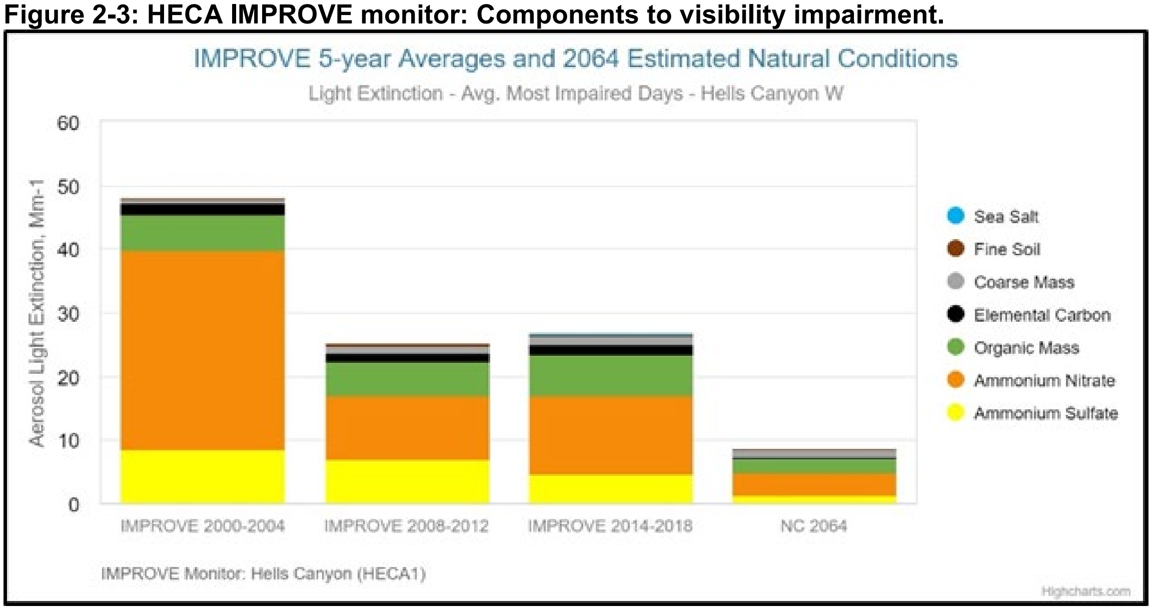


Figure 2-4: STAR IMPROVE monitor: Components to visibility impairment.

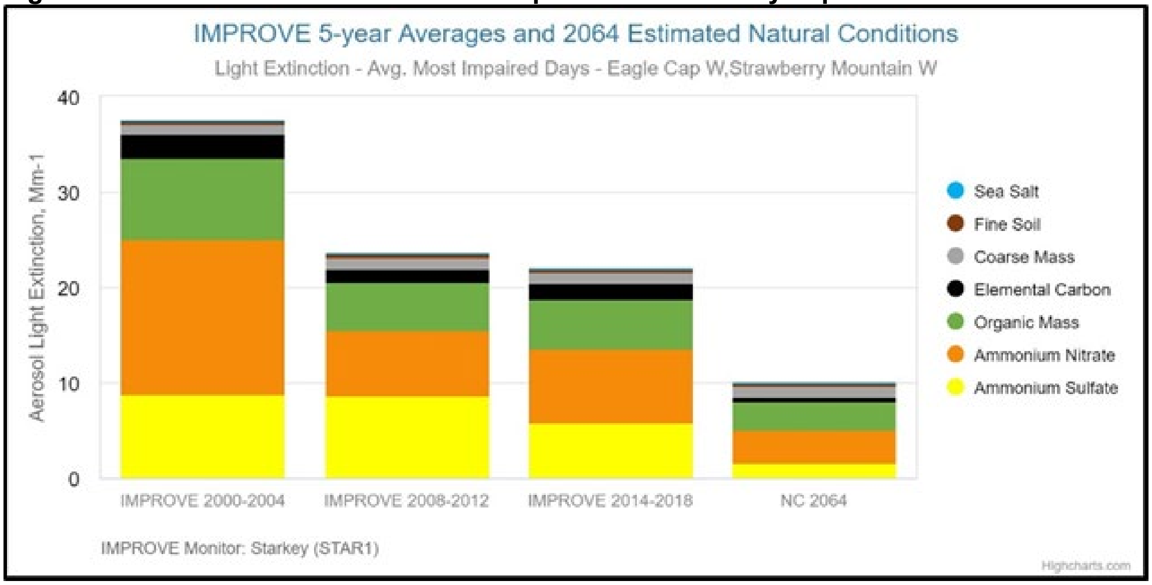


Figure 2-5: MOHO IMPROVE monitor: Components to visibility impairment

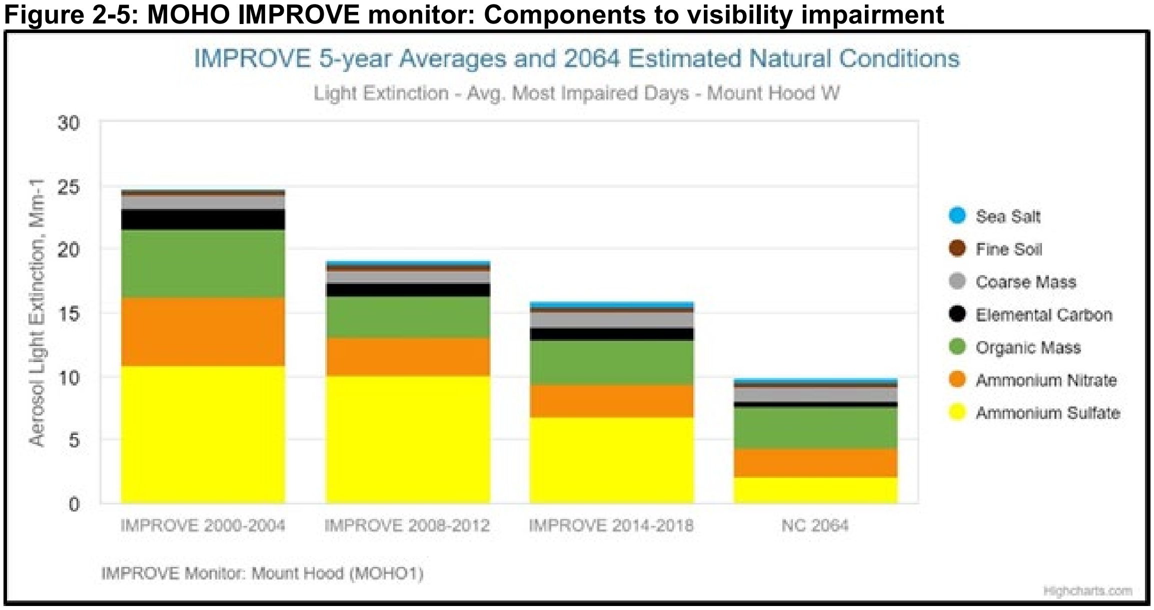


Figure 2-6: THSI IMPROVE monitor: Components to visibility impairment

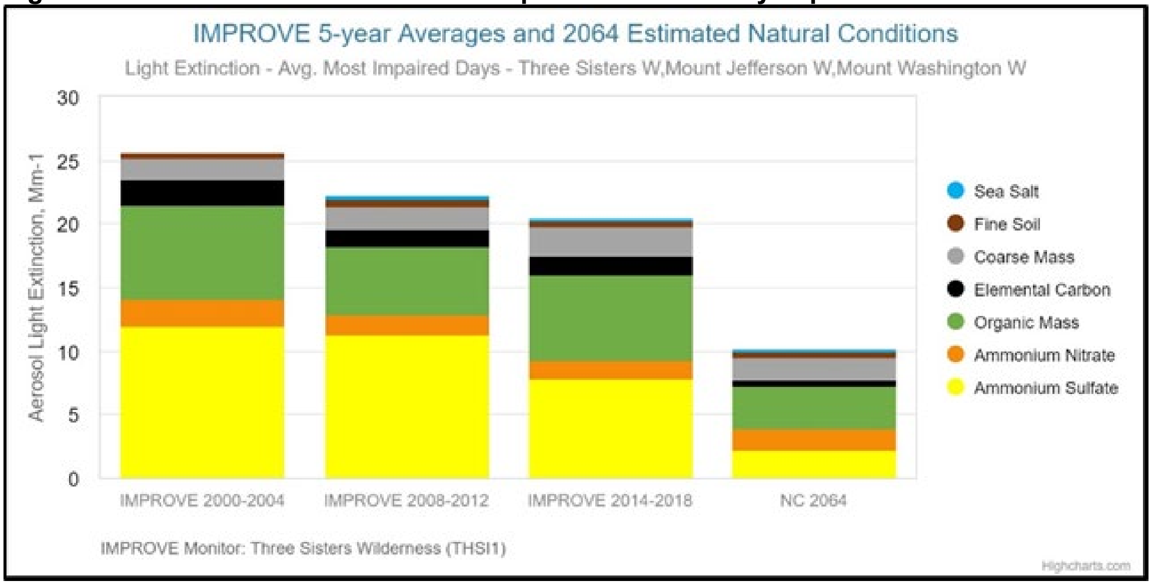


Figure 2-7: CRLA IMPROVE monitor: Components to visibility impairment

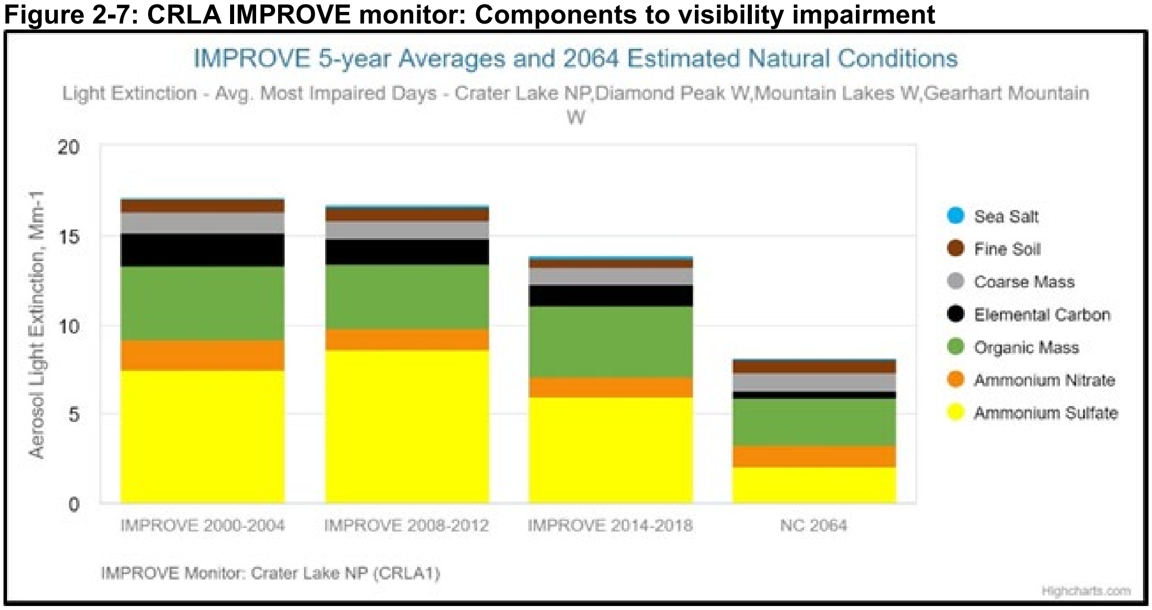
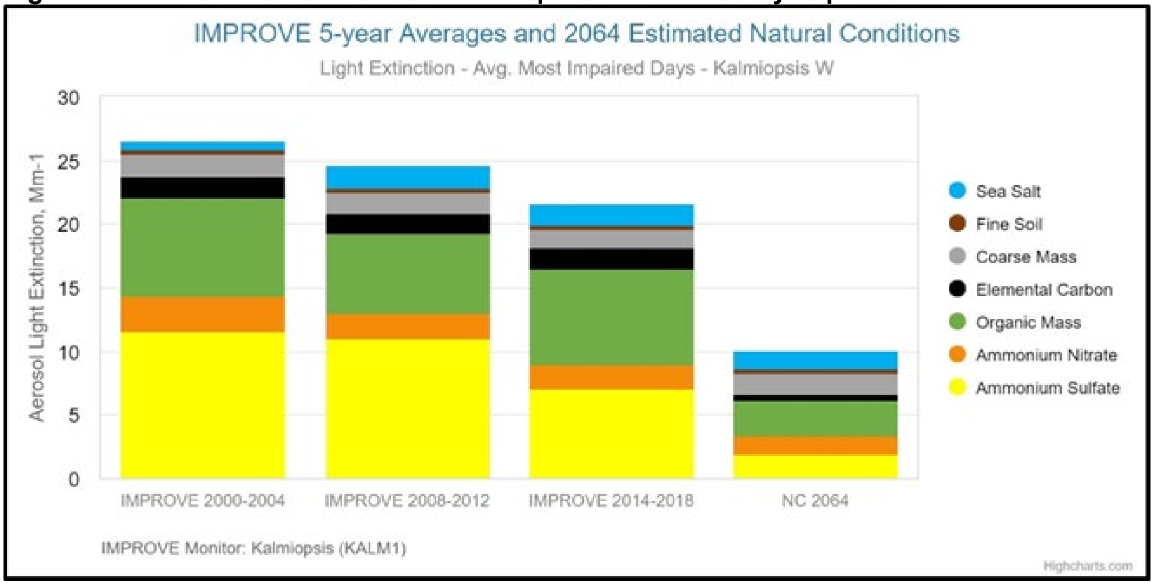


Figure 2-8: KALM IMPROVE monitor: Components to visibility impairment



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.

Figure 2-9 through Figure 2-14 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.

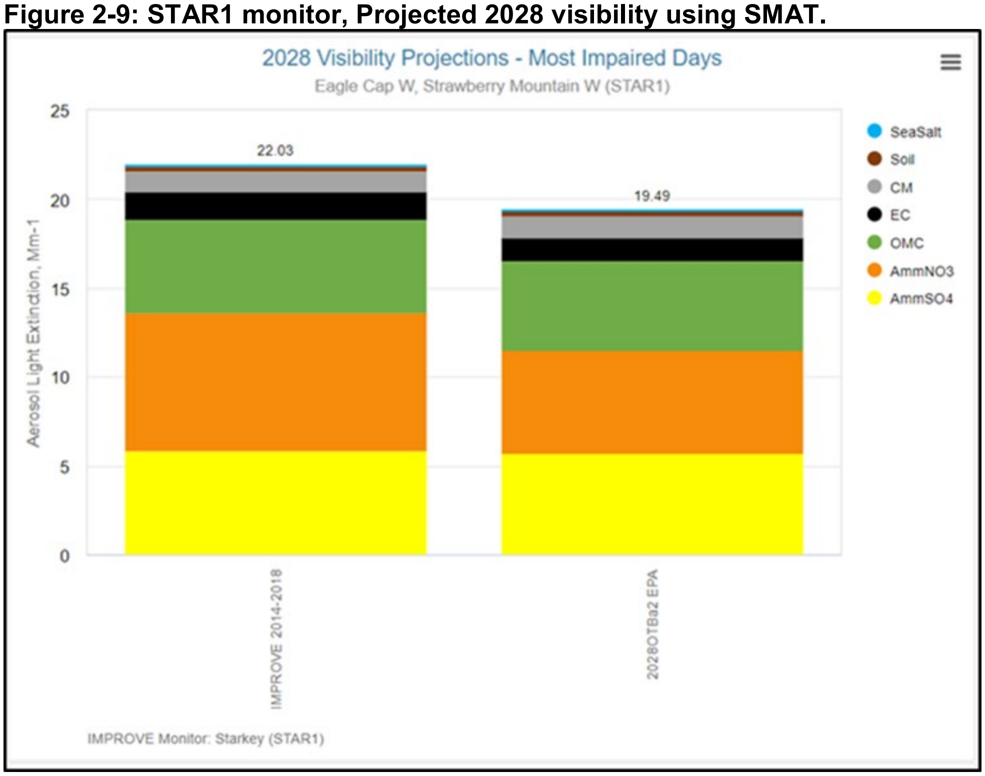


Figure 2-10: HECA monitor, Projected 2028 visibility using SMAT.

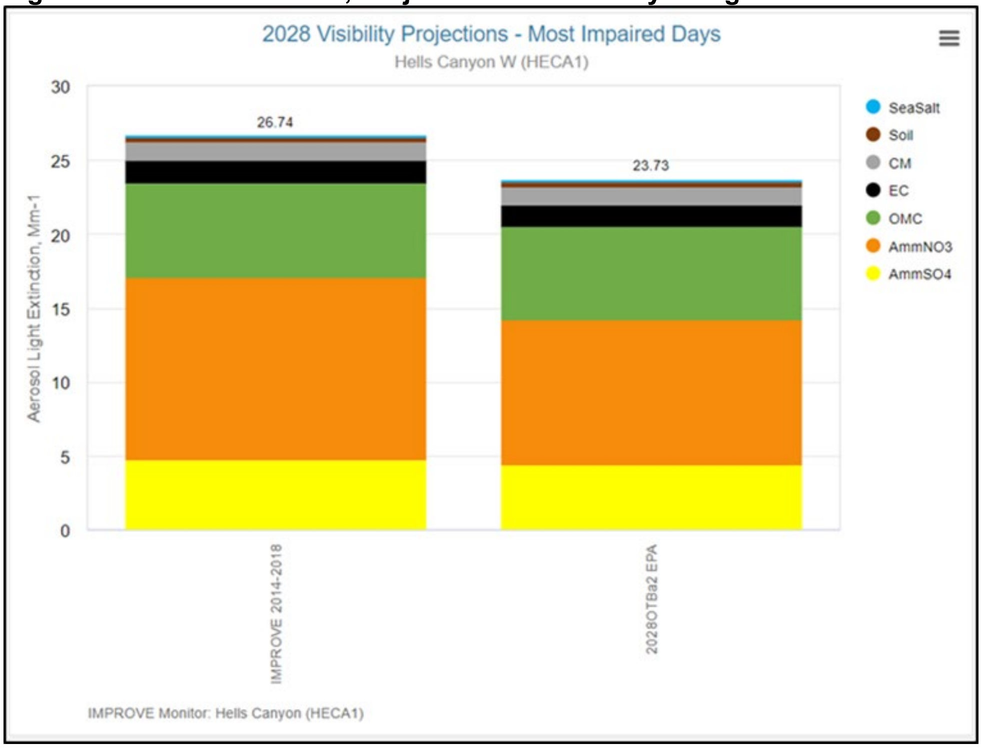


Figure 2-11: THIS monitor, Projected 2028 visibility using SMAT.

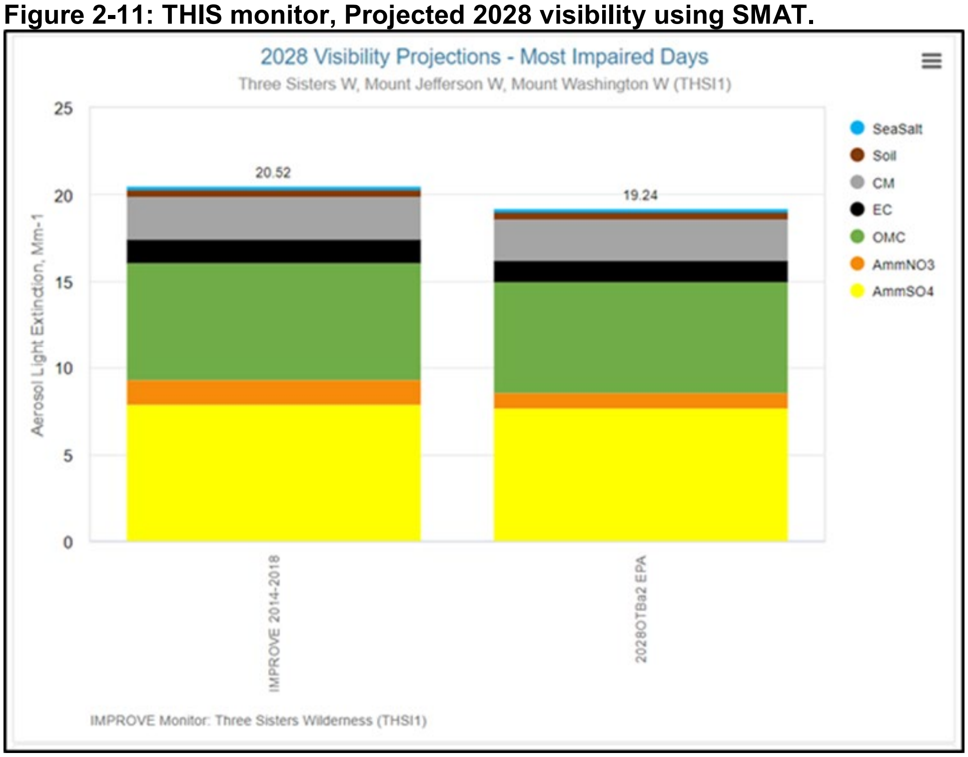


Figure 2-12: MOHO monitor, Projected 2028 visibility using SMAT.

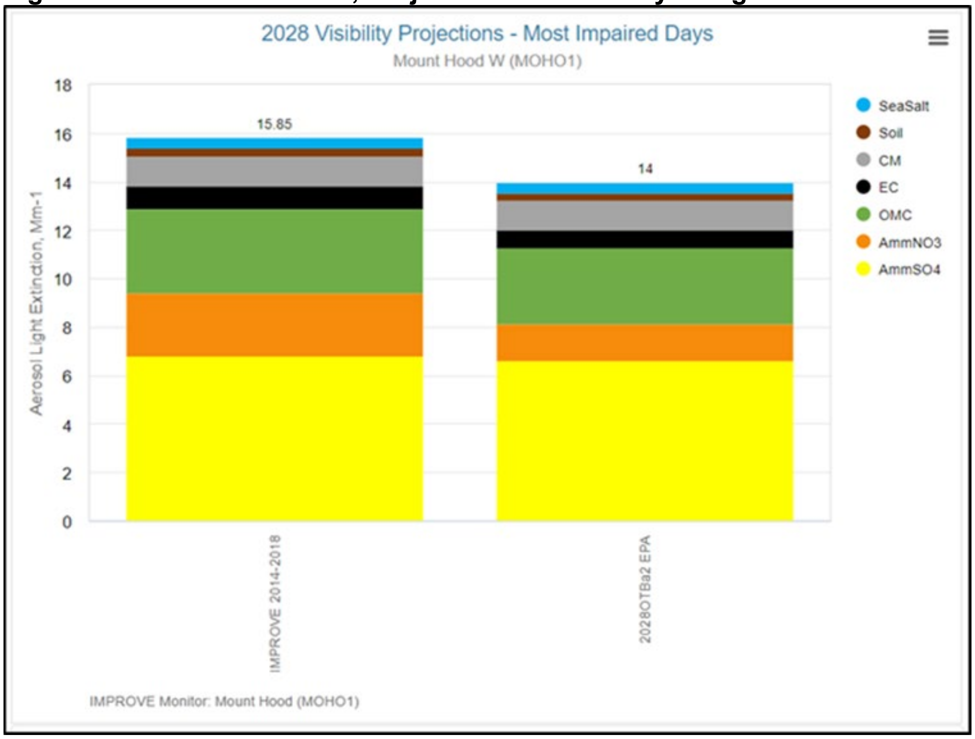


Figure 2-13: CRLA monitor, Projected 2028 visibility using SMAT.

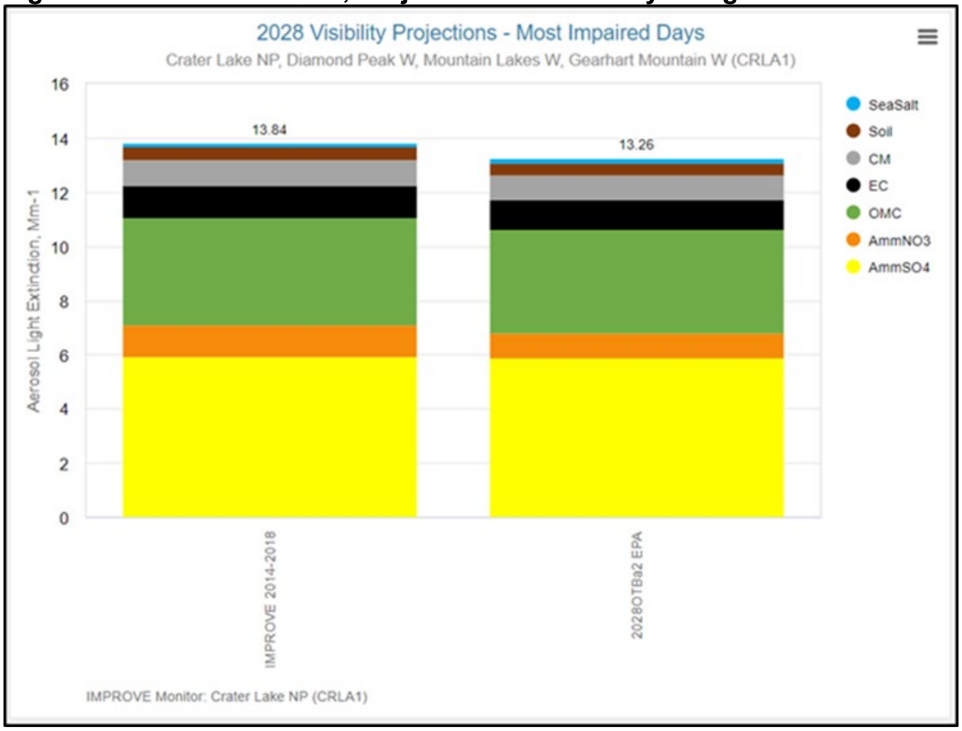
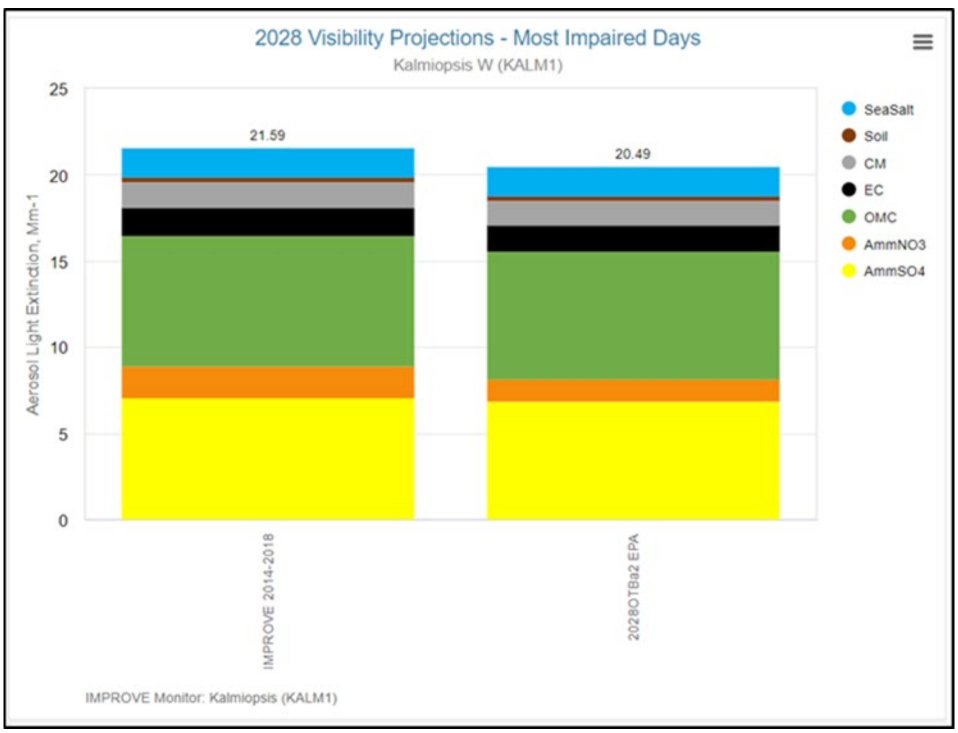


Figure 2-14: KALM monitor, Projected 2028 visibility using SMAT.



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 2-7 through Table 2-12 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 required 31 facilities where Q/d exceeded 5.00 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 NOx controls, in particular.

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.[15] 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.

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.

[15] 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)

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. Figure 3-1 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.

While Q/d values for the Columbia River Gorge NSA are included in the accompanying excel spreadsheet for reference, those values were not used to select sources for four factor analysis.

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.

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

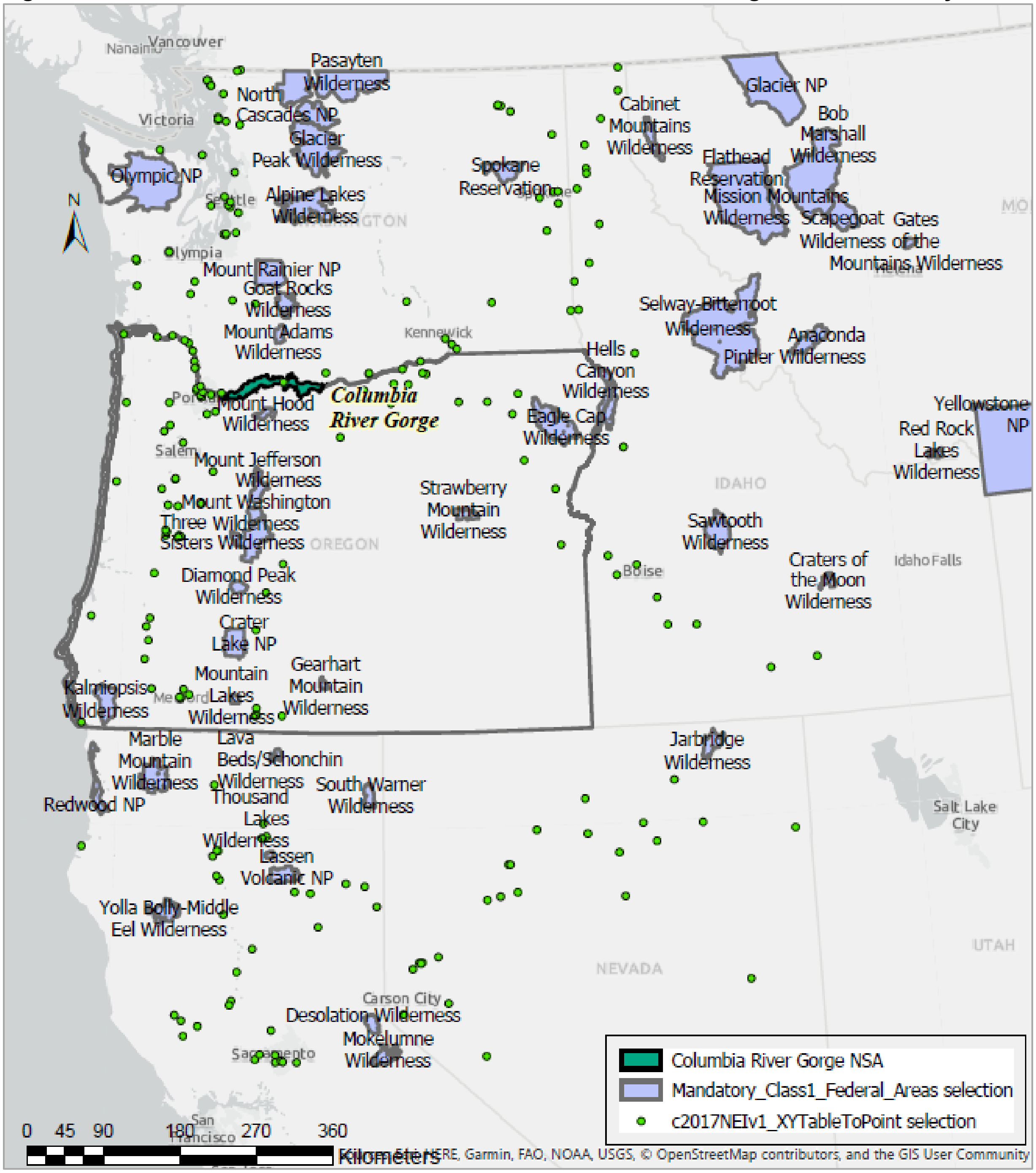


Table 3-2. Oregon facilities with Q/d greater than 5.00 that screened into four factor analysis. Also available online at: https://www.oregon.gov/deq/FilterDocs/haze-QDFacilitiesList.pdf

								Actual Emissions (tons per year)					PSEL (tons per year)					
Agency Facility ID	Facility Name	Permit	Fac State	Operating Status	EIS Facility ID	CIA Name	Distance (km)	NOX	PM10	SO2	Q	Q/d	NOX	PM10	SO2	Q(tpy)	Q/d	EmissYear
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. 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.[16] 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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[16] 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	NOX Act	PM10-PRI Act	SO2 Act	FFA Decision[17]
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.

[17] 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	NOX Act	PM10-PRI Act	SO2 Act	FFA Decision[17]
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%),[18] 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

[18] 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.

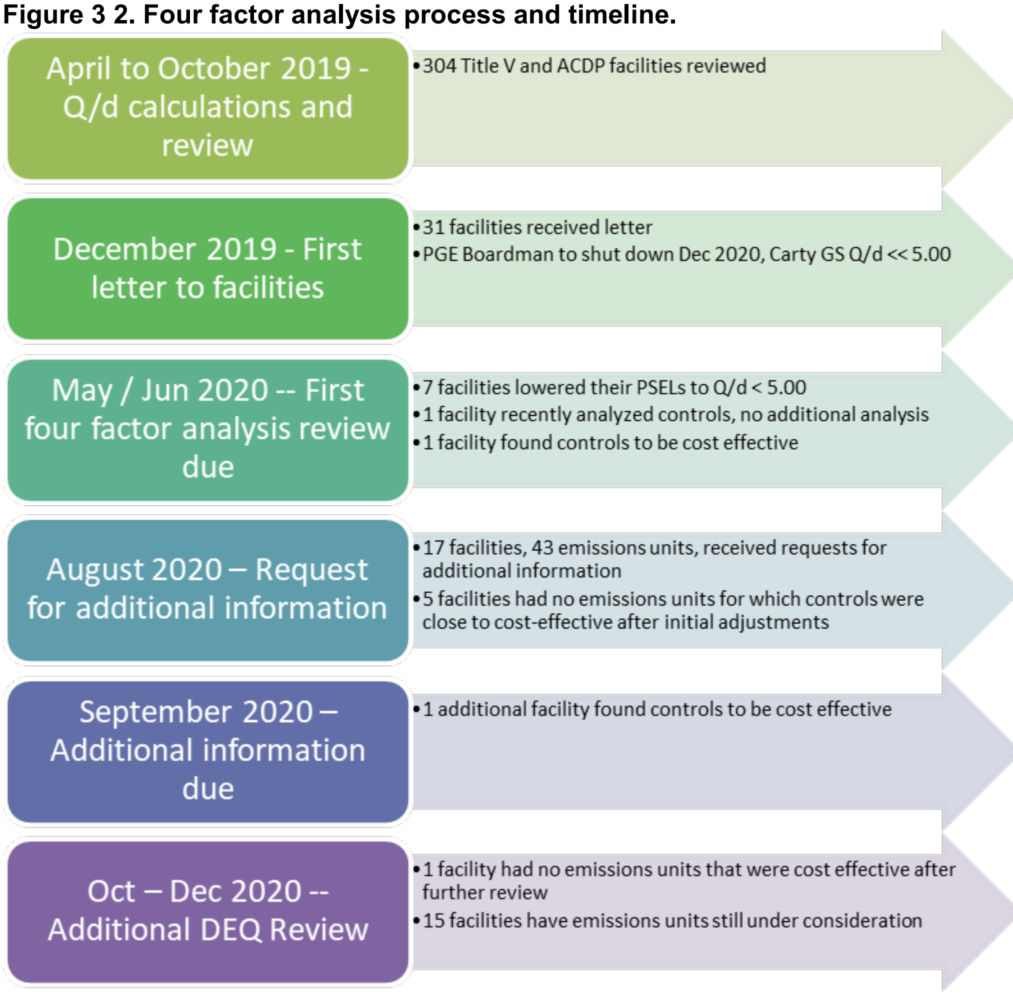
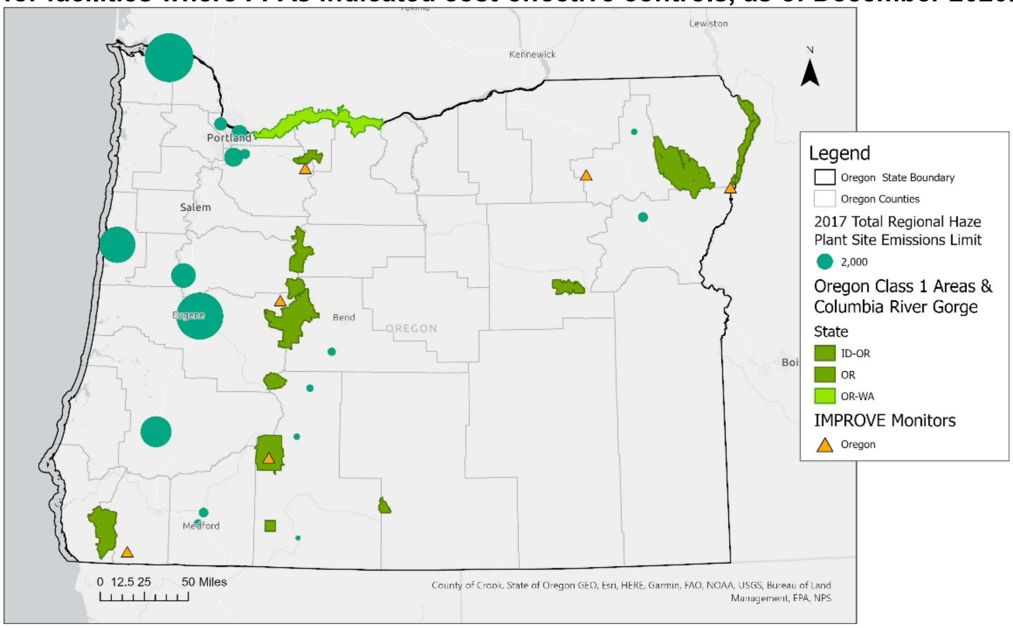


Figure 3-2 shows the total permitted emissions of regional haze-forming pollutants for the facilities where FFAs indicated cost-effective controls.

Figure 3-2. 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

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 (the non-air impacts of the FFA) potentially associated with facility controls. 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. For this Regional Haze plan, DEQ weighed the four factors as required 40 CFR 51.308 (d)(1)(i)(A) to determine reasonable progress goals, but following those determinations, considered visibility modeling results and co-benefits to better understand local environmental impacts.

DEQ followed the methodology described in Suter, *et al.* (2017) for qualitative assessments.[19] Table 3-4 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 cost of controls[20], 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[21] 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.

Factors that DEQ weighted lowest were remaining equipment life and time for compliance. DEQ decided that these factors, while valuable to consider, should not strongly influence which facilities should install controls; emission reductions benefit the environment and people regardless of when they are installed. Several other western states followed a similar weighting approach among first, second and third tier factors in their Regional Haze analyses.

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[19] 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)

[20] DEQ accounted for the burden that the cost of controls places on a facility in the cost effectiveness threshold described in Section 3.6.

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

Table 3-4. 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	+++	++	++	+++
Cost of controls		+++	+++	++	+++
Remaining useful life		+++	+	+	+
Time for compliance		+++	+	+	+
Energy and non-air 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.

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.[22]

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.

[22] 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.

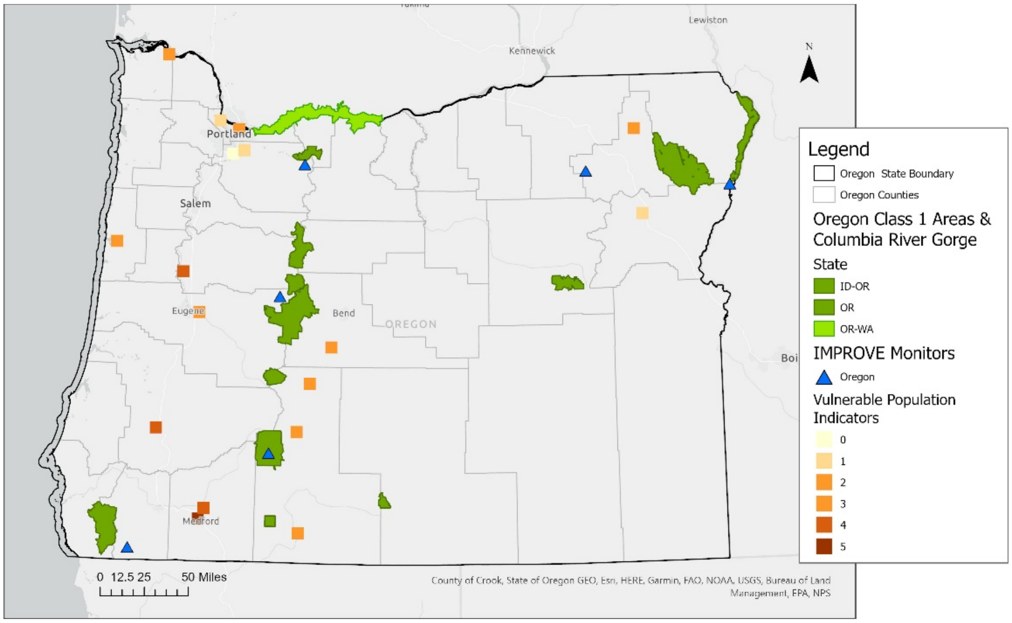
- Percent minority (percent population identifying as + percent of the population identified as Hispanic/Latino white)
- Percent low income (percent of population living in households making less than 200% of the federal income poverty level)
- Educational attainment (percent of the population over the 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 (Figure 3-3). 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 3-3 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 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 3-3. 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[23].

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.

The figures below are taken from the Washington Environmental Health Disparities Map Project[24] and Driver's et al. (2019) work on Maryland EJSCREEN.[25] 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.

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[23] 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.

[24] 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)

[25] 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)

As show in Figure 3-4, and summarized in Table 3-5, 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).
    - 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)[26] for an example of this methodology.

Figure 3.5 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.

[26] 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 3-4. A comparison of Washington Environmental Health Disparities map and Maryland's MD EJSCREEN.

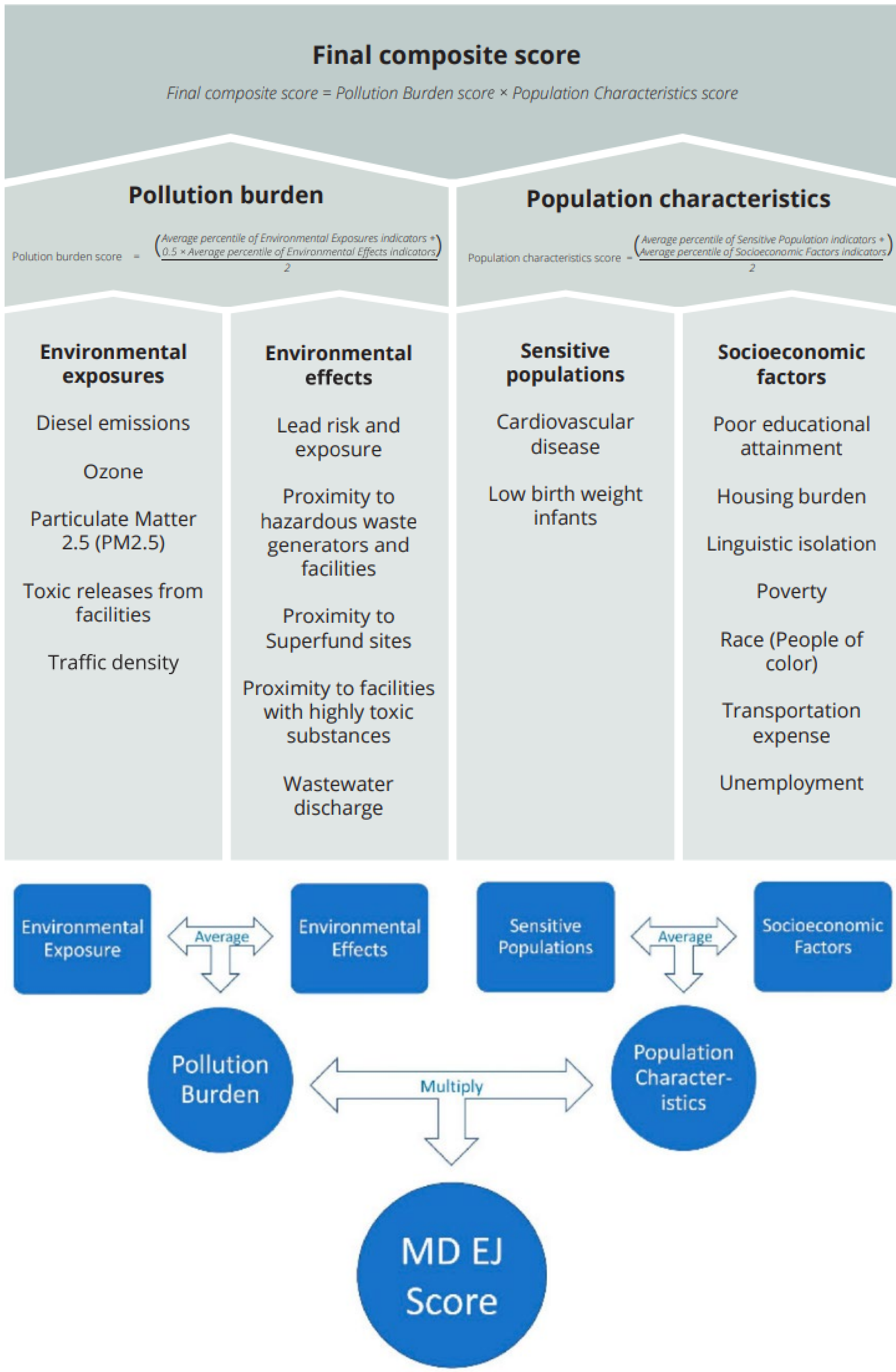
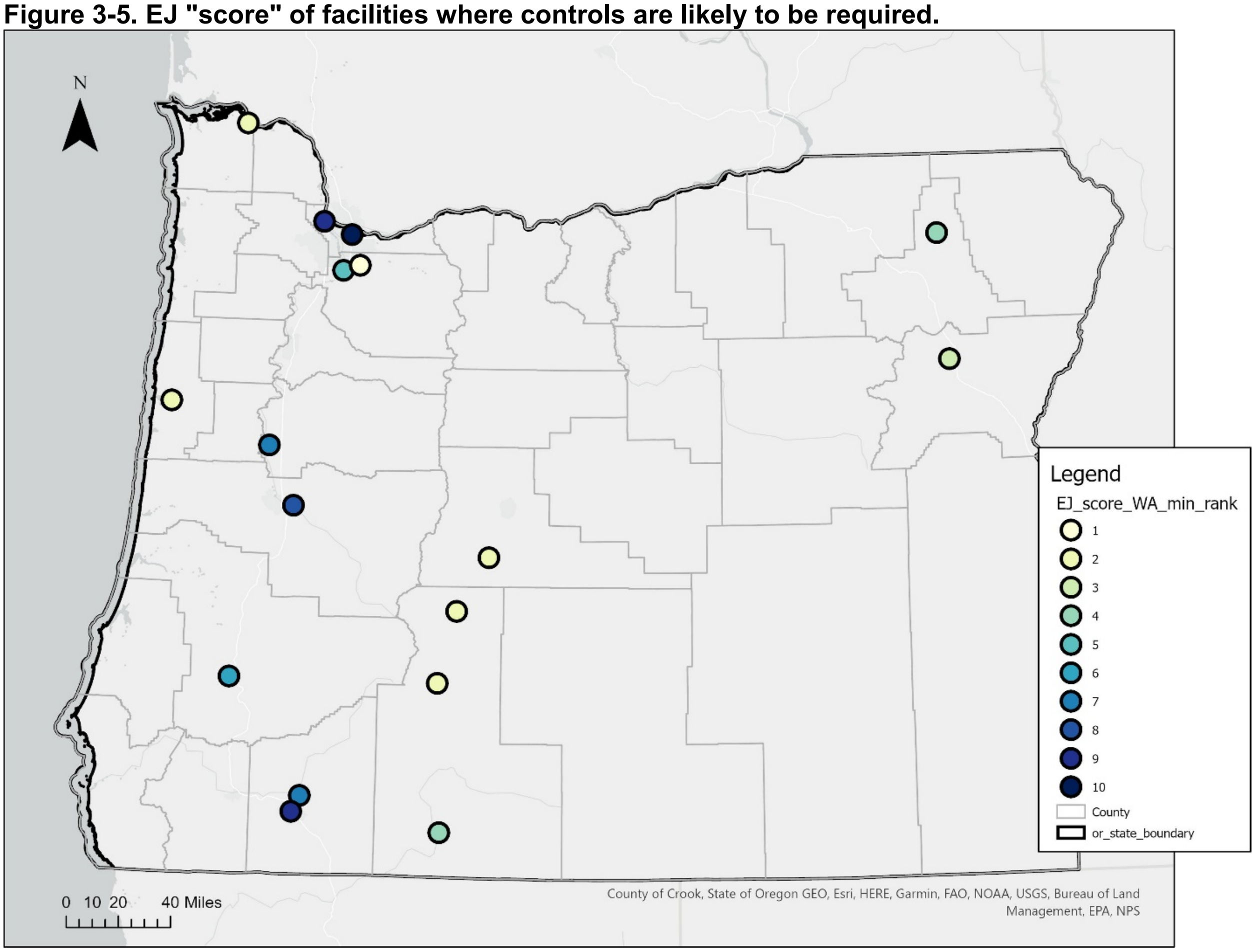


Table 3-5. Comparison of data inputs into CalEnviroScreen, WA Environmental Health Disparity Map, and MD EJSCREEN.

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 3-5. 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 3-6 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 3-6. 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.[27] 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 historic actions that EPA took on Portland Cement companies.[28]

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. 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 permit modification shall not be considered as a creditable contemporaneous emission decrease for the purposes of obtaining a netting credit under DEQ's PSD program.

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[27] 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)

[28] 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)

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. 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.

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 3-7). 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 included in Appendix E.

Table 3-7. Reduced PSELs for Kingsford Manufacturing (LRAPA #204402) to Q/d < 5.00.

	NO_x	SO_2	PM_{10}	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 SO2, PM10 and NOx 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 Timber Products Co. had reduced PSELs below the screening threshold of Q/d <= 5.00 in May 2020 (Q/d = 4.68; Table 3-8). Given the total emissions of the facility are now below the screening threshold of 5.00 via permit renewal, DEQ agreed that this facility did not need to undergo FFA for Regional Haze Round 2. The permit renewal application is included in Appendix E.

Table 3-8. 2020 PSELs for Timber Products Co (15-0025)

	2016 PSEL	2020 PSEL
NO_x	162	154
PM_{10}	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 SO2.
- 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 SO2.
- From On 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 SO2.
- 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 SO2.
- 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 SO2.

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 3-9). 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.

Table 3-9: Roseburg Forest Products - Riddle Plywood (10-0078) PSELs, July 2019 permit renewal Plant Site Emission Limits.

NOx (tons/year)	SO2 (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. The 2017 permit renewal is included in Appendix E.

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 NOx 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, and DEQ assigned specific pollutant levels through a permit modification. The modified permit is included in Appendix E.

Table 3-10. 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 facility met the criteria for further analysis. The FFAs are included in Appendix F.

- Collins Products, L.L.C. (18-0013)
- Columbia Forest Products, Inc. (18-0014)
- Ochoco Lumber Company (12-0032)
- Pacific Wood Laminates, Inc. (08-0003)
- Swanson Group Mfg. LLC (10-0045)

- Woodgrain Millwork LLC – Particleboard (31-0002)

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 (28-1865)

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.

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 NOx and 39 tons/year SO2. 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.

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. 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 NOx 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 NOx 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% NOx 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.

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 3-12, including Low NO_x Burners and SCR.

Table 3-11: 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 NOx burner on the lime kiln based on such installation not being likely to alter all the pathways to NOx formation and not necessarily resulting in a lower annual NOx emission rate.

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: PM10 = 1,077 tons/year; NOx = 2,019 tons/year; SO2 = 913 tons/year.
- On December 31, 2024, PSELs are PM10 = 1,077 tons, NOx = 1,999 tons, and SO2 = 913 tons.
- On July 31, 2026, PSELs are PM10 = 1,077 tons, NOx = 1,413 tons, and SO2 = 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 NOx 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 NOx 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 NOx 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 NOx 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. 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 NOx at Power Boiler #1.
- By December 31, 2022, finalize design of low NOx burner to be installed on Power Boiler #1, with objective to achieve 33% reduction is NOx emissions.
- By December 31, 2023, construct and install the low NOx 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.

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 + NOx + SO2 (Q/d = 6.53).
- From August 1, 2023, to July 31, 2024, the Permittee's PSELs are: 381 tons for PM10 + NOx + SO2 (Q/d = 6.29).
- From On August 1, 2024, to July 31, 2025 the Permittee's PSELs are: 365 tons for PM10 + NOx + SO2 (Q/d = 6.03).
- From August 1, 2025, to July 31, 2026 the Permittee's PSELs are: 347 tons for PM10 + NOx + SO2 (Q/d = 5.73).

- On August 1, 2026, the Permittee's PSELs for the following pollutants are: 302 tons for PM10 + NOx + SO2 (Q/d = 4.99).

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 SO2.
- 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 SO2.
- 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 SO2.
- 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 SO2.

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 - Springfield (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 3-13.

Table 3-12: Control devices DEQ found cost-effective at International Paper – Springfield facility.

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

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 SO2, 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 NOx from the Power Boiler and use data collected from the CEMS ·o demonstrate compliance with the NOx 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 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.

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 3-13. 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 3-13: Control devices DEQ found cost-effective at 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

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 NOx reduction project that includes the installation of low NOx 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 NOx 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 NOx reduction project:

  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.

  As expeditiously as practicable, but not later than July 31, 2026, install a CEMS to measure the emissions of NOx 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 SO2, 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, included in Appendix E, to 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 SO2.
- 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 SO2.
- From On 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 SO2.
- 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 SO2.
- 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 SO2.

Alternatively, the facility, up until July 2026, could opt to commit to replace units replace EU1 and EU2 with new technology 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.

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 LEC on EU1 (Ingersoll-Rand 412KVS Engines 1 and 2).

On August 9, 2021, Northwest Pipeline entered a stipulated agreement and order with DEQ, included in Appendix E, and 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 NOx optimization plan that describes the permittee's plan to use the CEMS data to operate in a way that minimizes NOx 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 NOx 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 NOx 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 these controls.

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 NOx 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 the Regional Haze SIP public notice. DEQ will include the Jeld-Wen permit modification in the final Regional Haze SIP submitted to EPA.

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 NOx and 5 tons/year for SO2. 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.

3.8 Federal Enforceability

This 2017 Regional Haze Rule (Section 51.308(f)(2)) requires that SIPs include enforceable emission limits and other measures necessary to meet reasonable progress goals toward natural visibility conditions. For each source required to reduce emissions, the SIP must include details such as compliance deadlines, monitoring requirements, averaging times, and requirements for record keeping and reporting. Provided a state has included such provisions in the SIP, the state may adopt the associated emission limits and other measures through a rule or other state regulatory requirement.

3.8.1 Rulemaking

In July 2021, DEQ completed rulemaking to codify the screening procedure to identify facilities requiring controls and the process followed to determine cost effectiveness of controls. The Environmental Quality Commission's 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. Each order specifies the emission limits (including averaging periods) achieved through control or PSEL reduction, a schedule for control installation or permit modification, monitoring to track compliance, and the source's record keeping and reporting requirements. Each order became effective on the issuance date. The orders for each facility required to install controls or reduce emissions – described in Section 3.6 – 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.

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 consider the five additional factors at 40 CFR 51.308(f)(2)(iv) in developing its long-term strategy, including:

- Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
- Measures to mitigate the impacts of construction activities;
- Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
- Source retirement and replacement schedules;
- Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the State for these purposes;
- Enforceability of emissions limitations and control measures; and

- 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 Stationary Source Emission Controls and PSEL Reductions

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 3.6. DEQ has issued a Department Order for each facility that mandates emission limits via control installation or PSEL reduction, compliance schedules, as well as monitoring, record keeping and reporting requirements. 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.

4.5 Mobile sources emissions analysis and controls

This 10-year Regional Haze plan incorporates and recognizes significant local and state efforts to reduce mobile source emissions. Key efforts include:

- As a section 177 state, DEQ is considering the adoption of several recent California rules for medium- and heavy-duty on-road vehicles. DEQ intends to propose new zero emission vehicle and NOx standards for medium- and heavy-duty trucks in late 2021 for EQC consideration.
- 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 plans to adopt 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. These standards would reduce greenhouse gasses and tailpipe emissions from new diesel vehicles by requiring a percentage of zero emission medium- and heavy-duty engines. The standards would also reduce NOx emissions from new medium and heavy-duty diesel engines by 90%. The standards would 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 NOx 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 late 2021 or early 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 NOx 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 Area source Emission Reduction

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

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.

4.6.2 Residential Wood Heating

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.

4.6.3 Open Burning

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.

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.

4.6.4 Other 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."[29] 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.

4.6.5 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

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

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 Volatile Organic Compounds

DEQ did not specify Volatile Organic Compounds as Round II 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 NAAQS, 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 increase 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. Although 2028 RPGs at some sites are slightly above the glidepath, 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).

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. Figures 5-1 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.

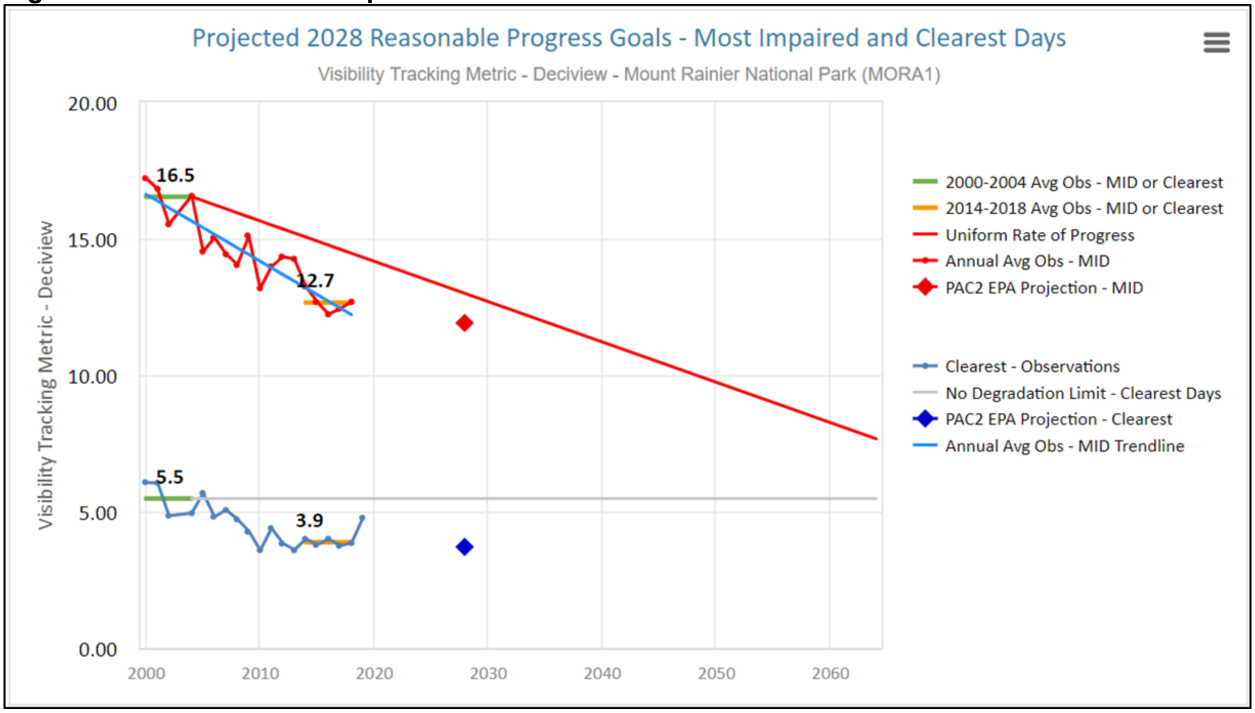


Figure 5-2: WHPA URP Glidepath and Modeled 2028 PAC2.

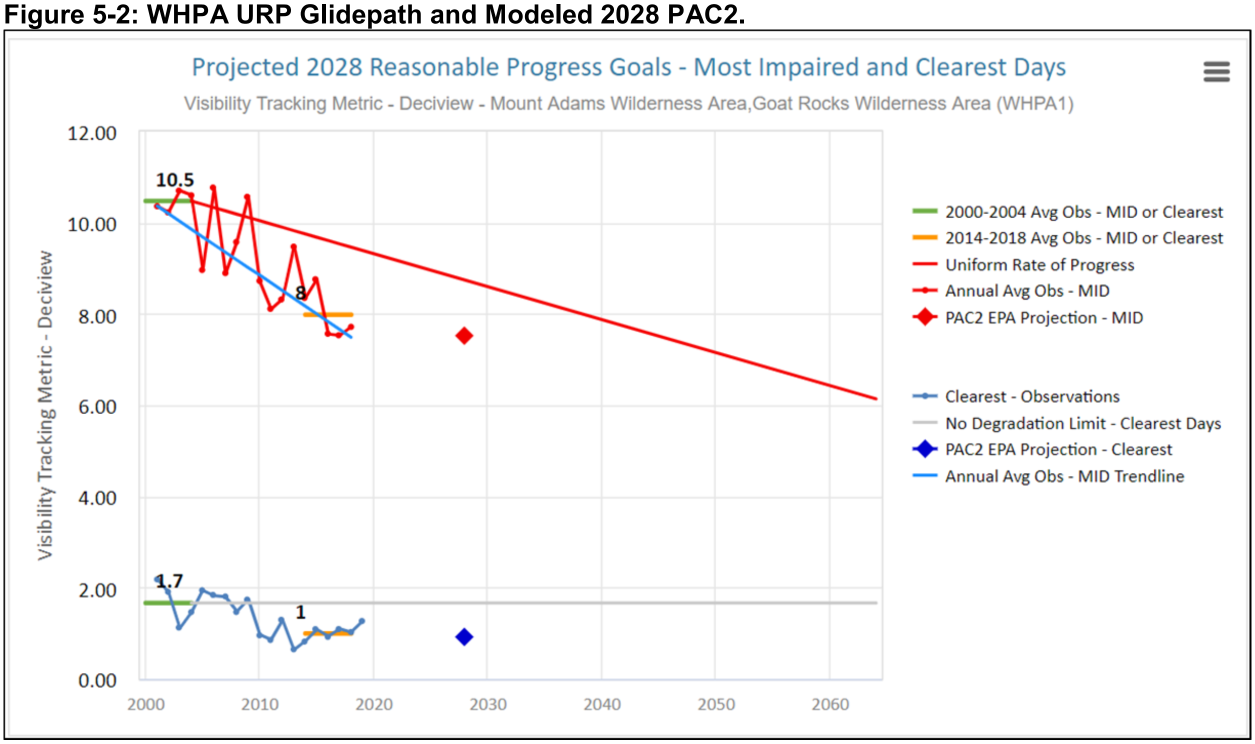


Figure 5-3: HECA URP Glidepath and Modeled 2028 PAC2.

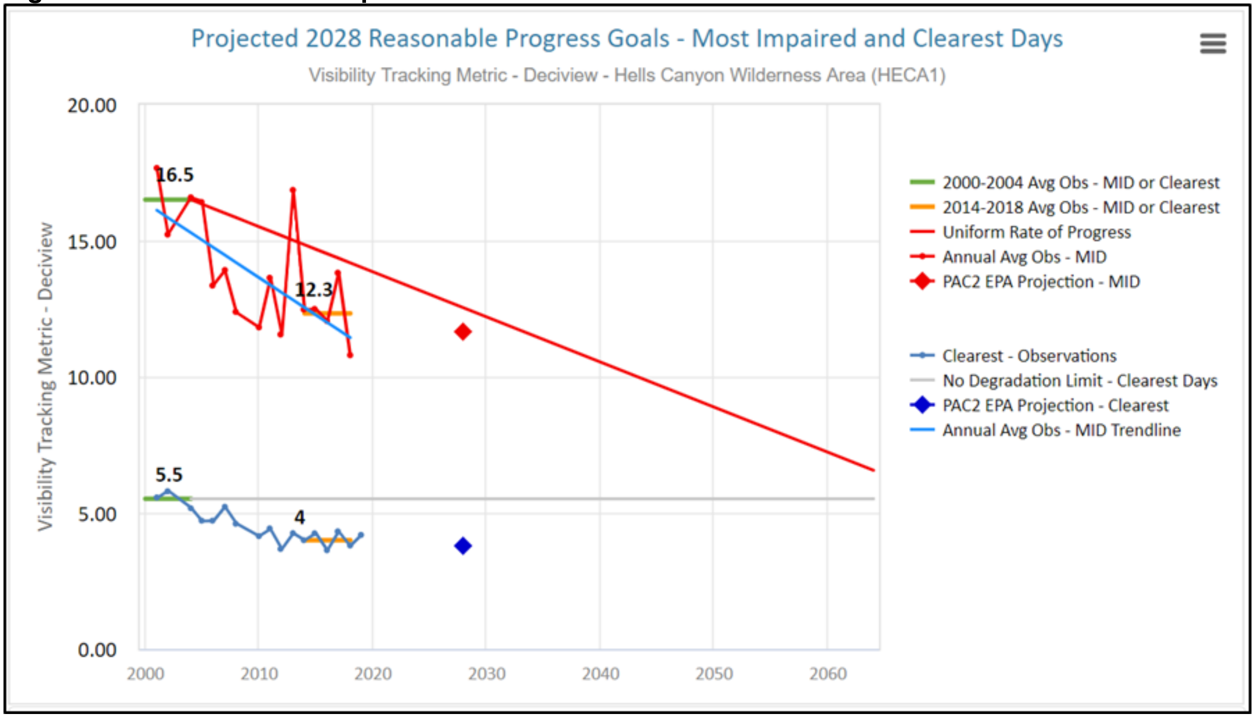


Figure 5-4: STAR URP Glidepath and Modeled 2028 PAC2.

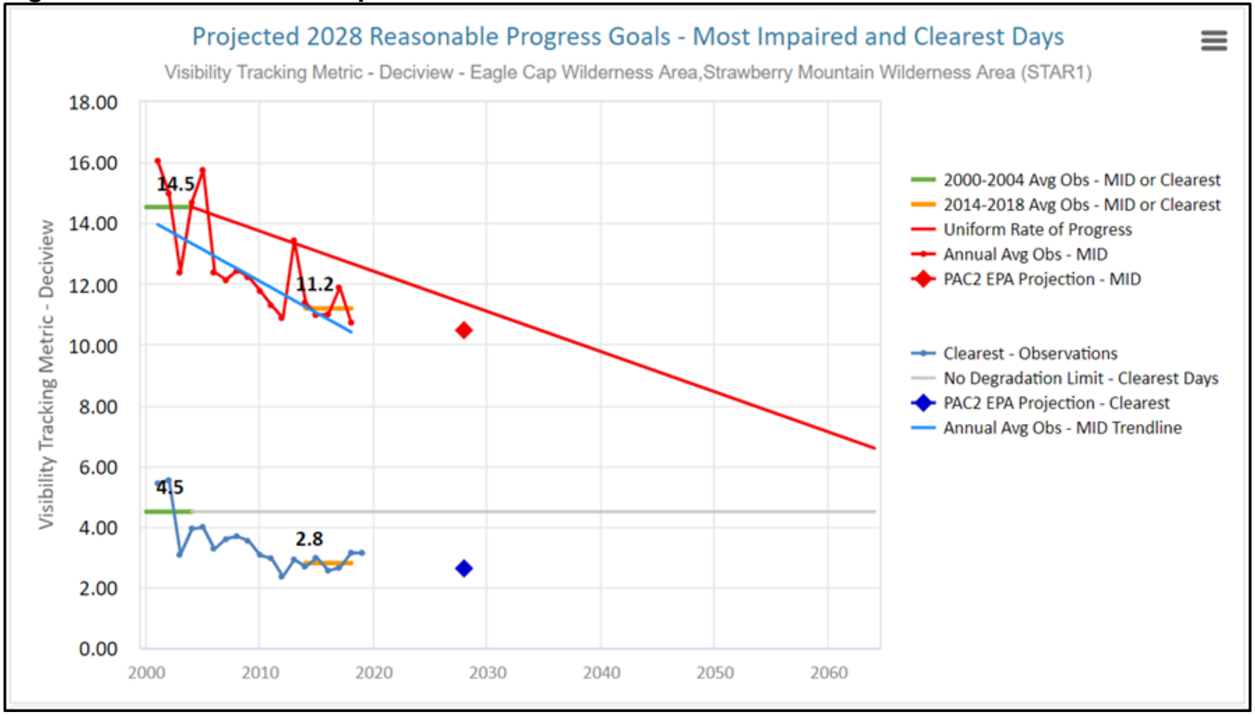


Figure 5-5: MOHO URP Glidepath and Modeled 2028 PAC2.

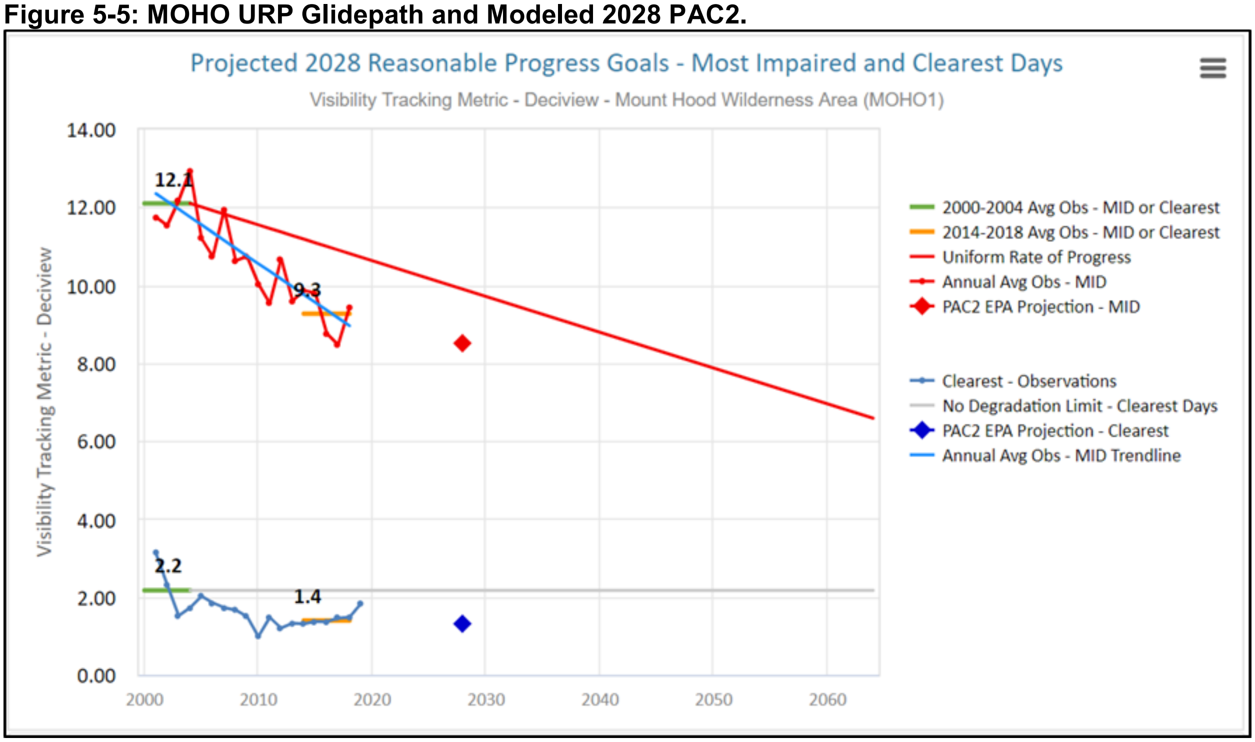


Figure 5-6: THSI URP Glidepath and Modeled 2028 PAC2.

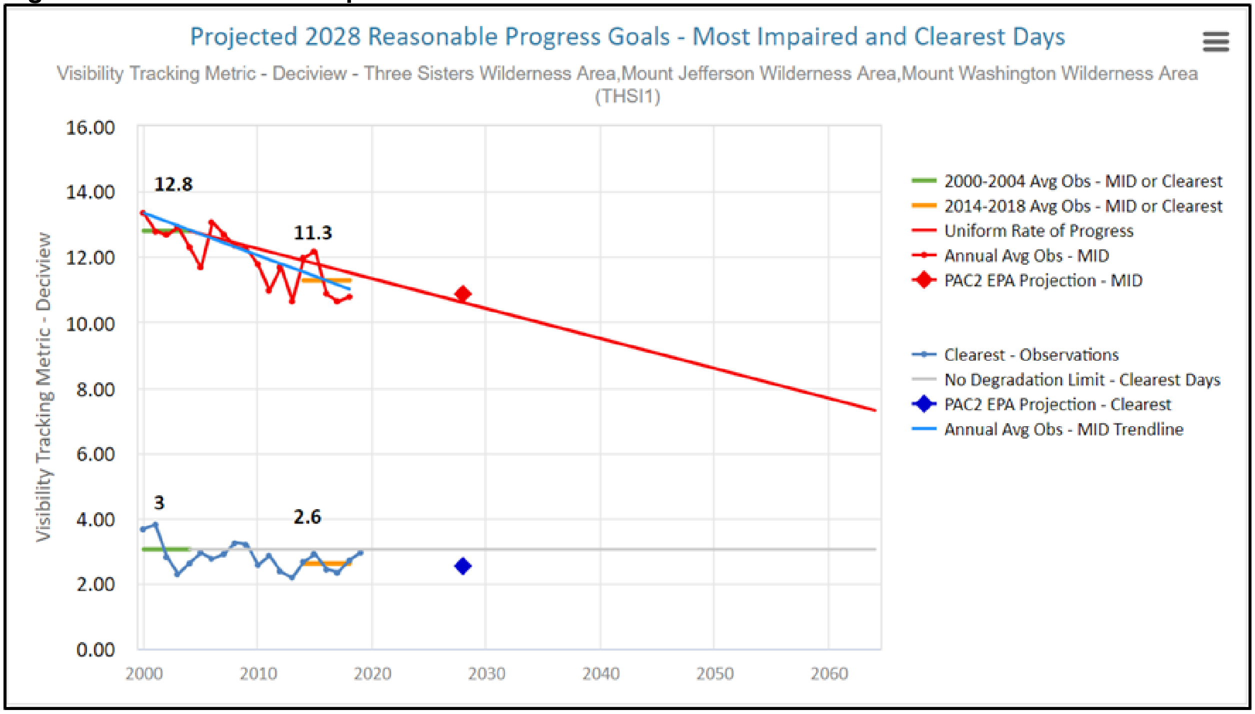


Figure 5-7: CRLA URP Glidepath and Modeled 2028 PAC2.

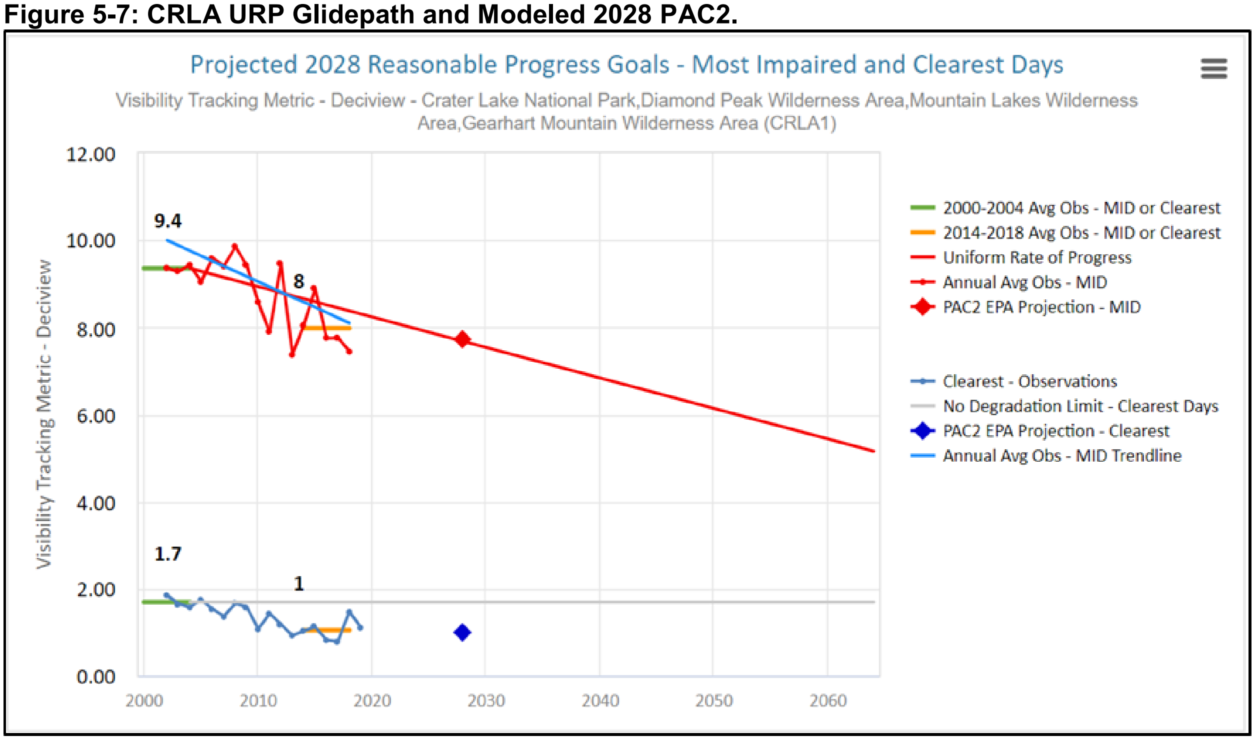


Figure 5-8: KALM URP Glidepath and Modeled 2028 PAC2.

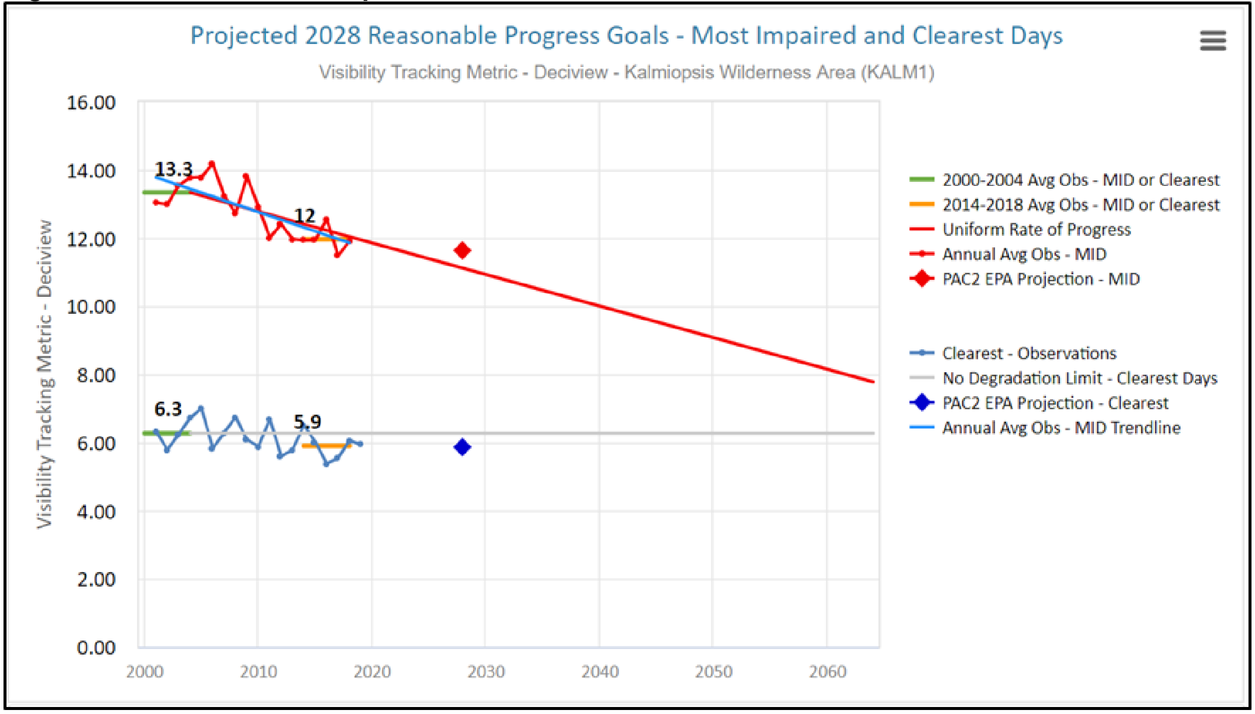


Figure 5-9: REDW URP Glidepath and Modeled 2028 PAC2.

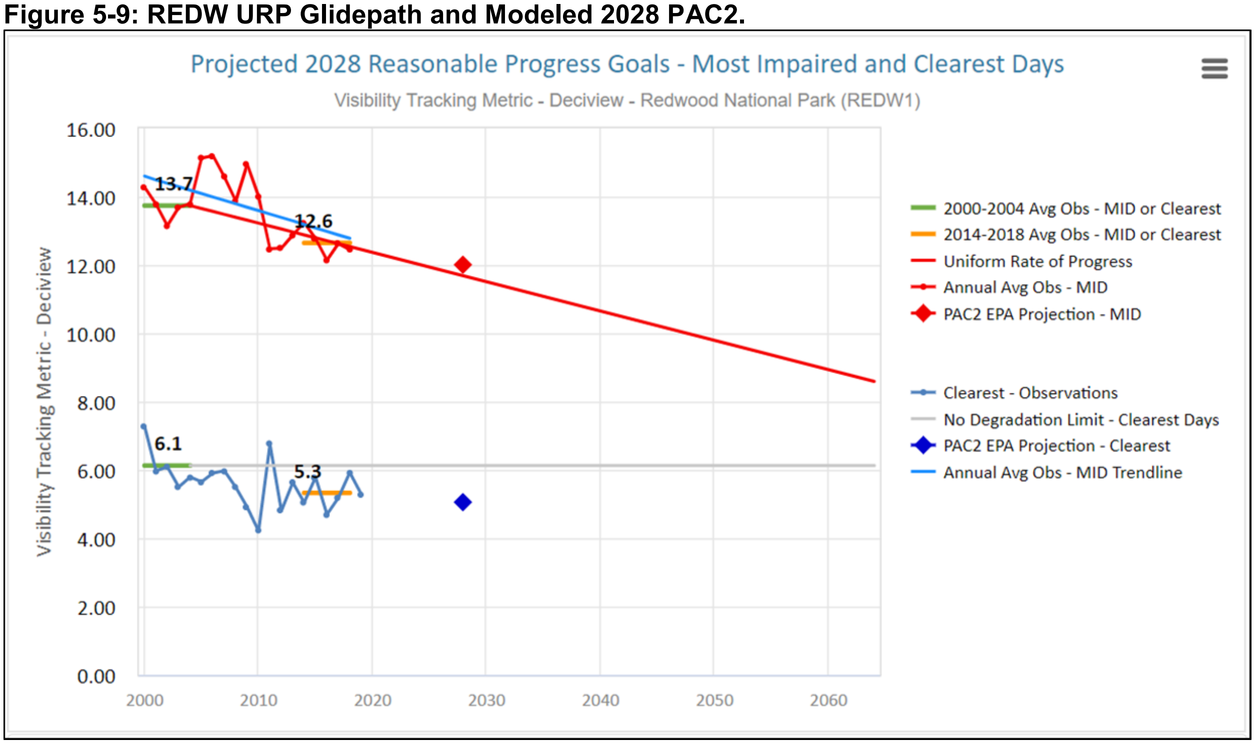
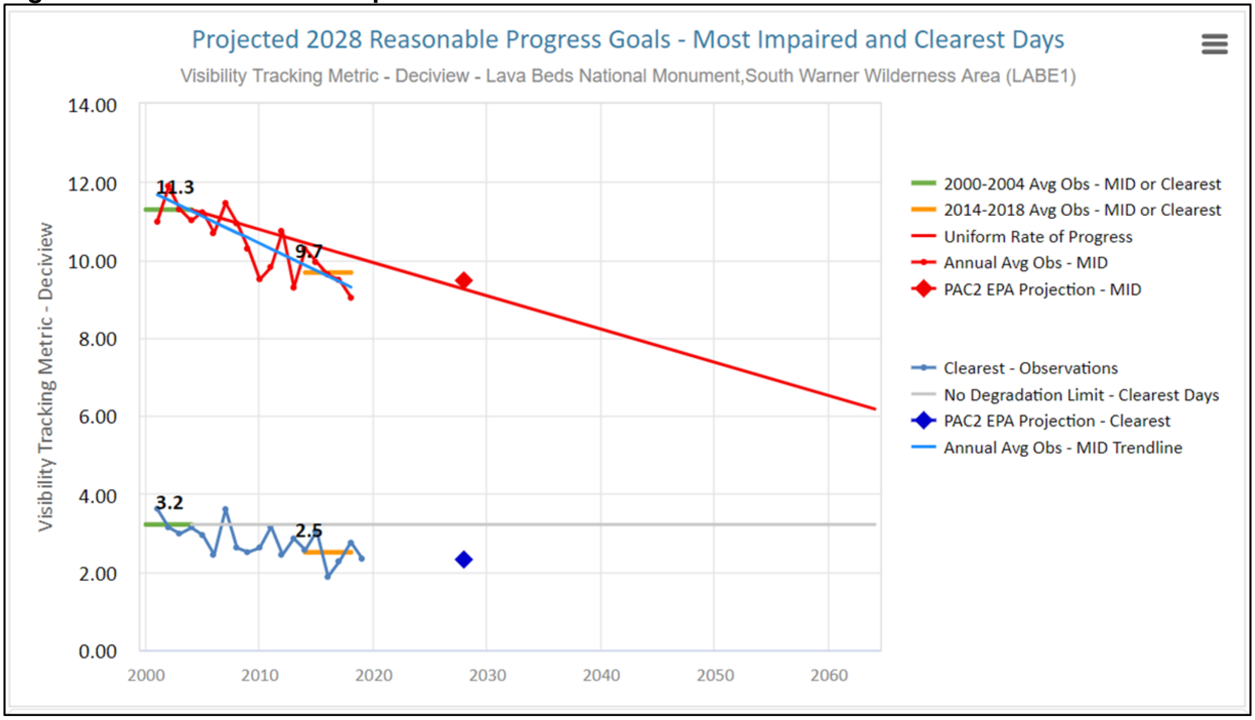


Figure 5-10: LABE URP Glidepath and Modeled 2028 PAC2.



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[30] 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.[31]

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 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.[32]

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

[30] http://nrc4tribes.org/files/Tab%209_9H%20Oregon%20SB770.pdf
[31] https://www.oregon.gov/deq/about-us/Pages/tribal.aspx
[32] https://www.wrapair2.org/

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.”

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 prelimary 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 NOx 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 (NOx + SO2 + 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 Facility-specific Comments

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

Facility ID	Facility	NPS Comment	DEQ Response
31-0006	Boise Cascade Wood Products, LLC - Elgin Complex	Concerns with All4 analyses 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. 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.	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 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.

		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.	
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 =	Please see DEQ Response to Boise Cascade – Elgin.

		$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%. $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 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.	Please see DEQ Response to Boise Cascade – Elgin.
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.	Please see DEQ Response to Boise Cascade – Elgin.

		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 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 was 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. Conclusions 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. 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.	
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.	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."

		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 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.	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.
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	Please see DEQ response to GTN Compressor station 12.

		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.	
15-0159	Biomass One, L.P.	April 2021 Comments 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. 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. June 2021 Comments 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).	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.
10-0025	Roseburg Forest Products - Dillard	April 2021 Comments 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 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	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

		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. 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).	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 had offered PSEL reductions, NOx emission limits, and continuous monitoring to verify compliance; DEQ continued to evaluate NOx 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 and comments

To be completed after public comment

6.5.3 Public information sessions

On October 22, 2020, and December 8, 2020, DEQ held public information sessions. 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.

6.6 DEQ responses to public comment

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
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

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	Three Sisters Wilderness	OR	237.18	431.25	4,612.00	1.82	19.44	359.22	62.19	9.85	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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	3,776.0 0	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
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	1,918.0 0	82.00	808.00	0.00	0.00	0.00

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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	1,372.0 3	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	1,372.0 3	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	1,372.0 3	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	1,037.6 6	775.80	539.82	2,139.0 0	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	1,037.6 6	775.80	539.82	2,139.0 0	1,077.00	913.00
04-0004	Georgia Pacific- Wauna Mill	OR	Goat Rocks Wilderness	WA	144.98	2,353.29	4,129.00	16.23	28.48	1,037.6 6	775.80	539.82	2,139.0 0	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	1,037.6 6	775.80	539.82	2,139.0 0	1,077.00	913.00

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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
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

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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
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

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
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
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

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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
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

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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
---	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

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	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
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

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
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
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

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
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	

Appendix D OAR Chapter 340 Division 223 Rules

Appendix E Orders and Permit Documents

Stipulated Agreements and Orders
Biomass One
Boise Cascade - Elgin
Boise Cascade - Medford
Cascade Pacific Pulp - Halsey
Cascade Tissue Group
EVRAZ
Gas Transmission Northwest Compressor Station #12
Georgia Pacific – Toledo
Georgia Pacific – Wauna
International Paper – Springfield
Northwest Pipeline – Baker City
Northwest Pipeline – Oregon City
Owens Brockway
Portland General Electric – Beaver
Roseburg Forest Products - Dillard
Willamette Falls Paper Co.

Unilateral Order
Gas Transmission Northwest Compressor Station #13

Permit Documents
Gilchrist Forest Products – Notice of Construction
Kingsford Manufacturing Co.
Klamath Energy LLC
Roseburg Forest Products – Medford
Roseburg Forest Products – Riddle
Timber Products

Appendix F Four Factor Analysis – No cost effective controls

Collins Products, L.L.C. (18-0013)
Columbia Forest Products, Inc. (18-0014)

Ochoco Lumber Company (12-0032)
Pacific Wood Laminates, Inc. (08-0003)
Swanson Group Mfg. LLC (10-0045)
Woodgrain Millwork LLC – Particleboard (31-0002)

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 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. 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 3-18. 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

<u>Power Boiler #3 SNCR</u>

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 3-16, 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 PM10, SO2, and NOX 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.

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[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 SO2 emissions. The CPP Halsey lime kiln's portion of the SO2 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 SO2 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 SO2 emissions from this kiln was evaluated (rather than replacing the venturi scrubber with a caustic wet scrubber and potentially decreasing the PM10 control efficiency).

SO2 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.

[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.

[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.

- **NPS Revised Analysis for Station 12:** 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.

Gas Transmission Northwest Compressor Station No. 13:

- 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.

- **NPS Revised Analysis for Station 13**: 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).