United States Department of the Interior

NATIONAL PARK SERVICE
Interior Regions 8, 9, 10, and 12
333 Bush Street, Suite 500
San Francisco, CA 94104-2828

IN REPLY REFER TO:
1.A.2 (PW-NR)

October 29, 2021

Oregon Department of Environmental Quality
Attention: Karen F. Williams
700 NE Multnomah St., Room 600
Portland, OR 97232-4100
email: RHSIP2021@deq.state.or.us

Dear Ms. Williams:

Thank you for the opportunity to review the proposed Oregon Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018-2028). Starting in January 2020, the National Park Service (NPS) engaged in early, informal consultation with the Oregon Department of Environmental Quality regarding SIP development. We appreciate the extensive efforts Oregon invested to engage early with the NPS. In consideration of the public review draft of the Oregon SIP, we provide additional comments which reiterate some of our initial recommendations and respond to new information.

Significant opportunities for emission reductions are available that could further improve the draft SIP. Specifically:

- We recommend Oregon require the most significant pollution reductions found to be technically feasible and cost-effective for facilities reviewed.
- The draft SIP would be strengthened by including a thorough technical justification for compliance strategies that achieve fewer emission reductions than originally proposed. See Enclosure 1 for detailed technical comments. We have also included Enclosure 2, a zipped file of calculation worksheets supporting NPS cost-effectiveness analyses.
- We recommend that control determinations be based on the results of four-factor analysis, rather than adjustments that allow facilities to retroactively avoid selection.

As we shared in our earlier feedback, the NPS appreciates that Oregon has: 1) selected a reasonable number of facilities to analyze for potential emission reductions; 2) tightened permitted emission limits to be more in-line with actual emissions; 3) established a reasonable cost-effectiveness threshold for emission controls; and 4) chose not to adjust glidepath goals for international emissions. We recognize that the draft SIP requires some reductions in haze-causing emissions which will make progress toward reducing haze in the region.

The NPS manages 48 of the 156 federally designated Class I areas across the country where visibility is an important attribute. NPS-managed Class I areas affected by haze-causing emissions from Oregon include Crater Lake National Park in Oregon, Mount Rainier National Park in Washington, Redwood National Park and Lava Beds National Monument in California, and Craters of the Moon National Monument & Preserve in Idaho. Haze can significantly diminish the visitor experience in these iconic parks that offer awe-inspiring vistas of snowcapped mountains, rugged volcanic landscapes, giant redwoods, and azure blue lakes.

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

We appreciate the opportunity to comment and look forward to continued work with Oregon for clean air and clear views. For questions or further information, contact Jalyn Cummings (jalyn_cummings@nps.gov) or Melanie Peters (melanie_peters@nps.gov).

Sincerely,

Cindy Orlando
Acting Regional Director
National Park Service, Interior Regions 8, 9, 10, and 12

Enclosures (2)
Enclosure_1_NPS-OR_RH-SIP-Feedback_11.2021_1.pdf
Enclosure 2_NPS-OR_RH_CalculationSpreadsheets.zip

cc: Stephanie Burkhart, Acting Deputy Regional Director
Denise Louie, Regional Natural Resources & Science Lead
Jalyn Cummings, Regional Air Resources Program Manager
Melanie Peters, Air Resources Division Regional Haze Lead

National Park Service (NPS) Regional Haze SIP feedback for the Oregon Department of Environmental Quality

November 1, 2021

Contents

1 General/Process

Under the Clean Air Act (§§169A and B) and Federal Regional Haze Rule (40 CFR §51.308), states are required to develop SIPs and engage substantively with agencies that manage national parks and wildernesses designated as Class I areas. States are also required to update SIPs every 10 years to address air pollution and to ensure progress towards achieving the goal for "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution."

1.1 Consultation

The NPS participated in informal early engagement with the Oregon Department of Environmental Quality (ODEQ) regarding SIP development beginning in January of 2020. This included a preliminary coordination meeting on May 25th, 2021 and subsequent written documentation of NPS feedback on July 1st, 2021. In addition, NPS staff provided ongoing technical feedback on individual facility four-factor analyses as documented in the draft Oregon SIP. We appreciate the extensive efforts that Oregon invested in early engagement with the NPS.

As we shared in our earlier feedback, we appreciate that Oregon: 1) selected a reasonable number of sources to analyze for potential emission reductions, 2) tightened permitted emission limits to be more in-line with actual emissions, 3) established a reasonable cost-effectiveness threshold for emission controls, and 4) chose not to adjust glidepath goals for international emissions. We recognize that the draft SIP requires some haze-causing emission reductions and will make progress toward reducing haze in the region.

Oregon's strategies to address visibility impairment presented in the current draft SIP were first shared with the NPS when the draft was made available for public comment. In consideration of the public review draft of the Oregon SIP, we provide additional comments which reiterate some of our initial recommendations and respond to new information.

1.2 Revised Control Determinations

Significant opportunities for emission reductions are available that could improve the draft SIP. Specifically:

- We recommend Oregon require the most significant pollution reductions found to be technically feasible and cost-effective for facilities reviewed.
- The draft SIP would be strengthened by including a thorough technical justification for compliance strategies that achieve fewer emission reductions than originally proposed. Enclosure 2 is a zipped file of calculation worksheets supporting NPS cost-effectiveness analyses.
- We recommend that control determinations be based on the results of four-factor analysis, rather than adjustments that allow facilities to retroactively avoid selection.

1.3 Editorial Note

On page 100 of the draft SIP, regarding responses to NPS comments, the NPS is quoted as saying:

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

The NPS comment, in fact, read:

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

2 Wood Product Facilities Feedback

The wood products facilities selected by ODEQ for four-factor analyses (4FA) are:

- Collins Wood Products, L.L.C.
- Ochoco Lumber Company
- Pacific Wood Laminates, Inc.
- Swanson Group Mfg. LLC
- Woodgrain Millwork LLC – Particleboard
- Gilchrist Forest Products
- **Boise Cascade Wood Products, LLC - Elgin Complex**
- **Georgia Pacific - Wauna Mill**
- **Cascade Pacific Pulp, LLC - Halsey Pulp Mill**
- **Boise Cascade Wood Products, LLC - Medford**
- **International Paper - Springfield**
- **Georgia-Pacific – Toledo LLC**
- Roseburg Forest Products - Dillard
- Willamette Falls Paper Company
- Columbia Forest Products, Inc.

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

In its draft RH SIP, regarding the Boise Cascade Elgin facility, ODEQ stated:

> *DEQ acknowledges additional corrections that NPS recommends, such as retrofit factor, CEPCI, operating costs, reagent costs and property tax; however, DEQ generally did not correct for such factors if DEQ had already concurred on the technical infeasibility of*

certain controls or was working with facilities to pursue alternative methods of emission reductions.

For other wood products facilities (BC-Medford, GP-Wauna, GP-Toledo, CP-Halsey), ODEQ simply stated:

Please see DEQ Response to Boise Cascade – Elgin.

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

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

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

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

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

- In ODEQ's review of the power boilers at Georgia Pacific's (GP's) Toledo mill, ODEQ changed GP's 1.5 retrofit factor "to 1 because there is no vendor data" consistent with EPA's Control Cost Manual (CCM) spreadsheet which advises "You must document why a retrofit factor of (>1.0) is appropriate for the proposed project."
- We generally agree with ODEQ's decision for GP-Toledo. Acceptance of the 1.5 retrofit factor should also be justified for the other facilities with documentation of cost-effectiveness analysis. Application of an un-documented retrofit factor significantly inflates the capital cost of SCR.
- A 20-year life for the Boise Cascade boilers was assumed, in contrast a 25-year life was assumed for all other OR and WA woodwaste-fired boilers. This difference should be explained.
- For the Boise Cascade boilers, a 2019 Chemical Engineering Plant Cost Index (CEPCI) = 603.1 was used; the correct CEPCI = 607.5.
- A 4.75% interest rate was applied instead of the current bank prime rate of 3.25% as recommended by the CCM.

- The operating times calculated by the CCM spreadsheets were over-ridden by the paper mills and higher values were substituted. This resulted in significant overestimation of operating costs that are based upon hours of operation.
- The reagent (ammonia) cost/gallon used by the paper mills in their SCR spreadsheets is an order of magnitude greater than the default value contained in the CCM SCR spreadsheet. The higher reagent cost should be documented or revised to be consistent with the CCM default cost/gallon.
- The paper mills included costs for reheating the boiler outlet gas streams to facilitate application of SCR. While reheat may be necessary if the SCR is applied downstream of emission control devices that reduce the temperature of the gas stream, it would not be necessary for SCR applied to the natural gas-fired power boilers common to these mills. Where reheat is appropriate, e.g., for a biomass-fired boiler with particulate controls, the amount of natural gas needed to reheat the gas stream should be explained and justified. It is our understanding that the only biomass-fired boilers were the Fluidized Bed Boiler at GP-Wauna and the boilers at the Boise Cascade facilities. Analyses would benefit from an explanation of the reheat costs.
- Property taxes were included in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

In its draft RH SIP, ODEQ noted that:

DEQ adjusted cost estimates for consistency among emissions units, including adjustment to current prime rate (3.25%), 30-year lifetime, and emissions at plant site emission limit (PSEL).

- DEQ removed sales tax costs from FFA analysis as Oregon has no sales tax.
- DEQ acknowledges additional corrections that NPS recommends, such as retrofit factor, CEPCI, operating costs, reagent costs and property tax; however, DEQ generally did not correct for such factors if DEQ had already concurred on the technical infeasibility of certain controls or was working with facilities to pursue alternative methods of emission reductions.

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

3 Facility Specific Feedback

3.1 Owens-Brockway Glass Container Inc.

According to the Oregon draft SIP:

> *In a letter dated October 27, 2020, DEQ concurred with Owens-Brockway's findings in FFA submitted on June 12, 2020, that costs of installing controls were reasonable. Specifically, DEQ concurred with the findings that combined control of NO_x, SO_2 and PM by catalytic ceramic filters is cost-feasible for the facility's glass-melting furnaces A and D.*
>
> *Owens-Brockway informed DEQ by an April 27, 2021, letter that the facility intended to shut down Furnace A permanently and request Furnace A and its emissions units' removal from their Title V permit. Rather than install controls, Owens-Brockway chose the alternative compliance option to lower PSELs. On August 8, 2021, Owens Brockway entered a stipulated agreement and order with DEQ to accept federally enforceable reductions of combined PSELs for Round 2 Regional Haze pollutants to bring the facilities Q/d below 5.00.*

NPS Comment: We agree that the permanent shutdown of Furnace A is an actual emissions reduction at the facility. We also observe that additional emission controls for furnace D are cost effective and request that Oregon require these controls or equivalent reductions. Alternatively, an analysis demonstrating that PSEL reductions agreed to will meet this standard would improve the SIP.

The ODEQ agreement stipulates in part that:

- *On and after January 1, 2022, the permittee shall comply with the following PSELs, which apply to each 12 consecutive calendar month period after that date: 55 tons/year PM_{10}, 137 tons/year NO_x, and 108 tons/year SO_2.*
- *On July 21, 2025, the permittee's PSELs for the following pollutants are: 274.95 tons/year PM_{10} + NO_x + SO_2, which results in a Q/d = 4.99.*

NPS Comment: Based on the company's own analysis (dated June 12, 2020) the cost of catalytic ceramic filters on Furnace D alone are $5,035/ton to control NO_x, SO_2, and PM simultaneously. A Dry Scrubber + ESP + SCR on Furnace D alone would be $6,883/ton to control NO_x, SO_2, and PM. (See Table 11 in the company's four-factor analyses). The company used a 7% interest rate and a 20-year equipment life. Even with the higher interest rate, these costs are well within ODEQ's cost-effectiveness threshold for furnace D.

3.2 Boise Cascade Wood Products, LLC - Elgin Complex

3.2.1 NPS Review of Eglin

From the draft SIP, ODEQ:

In a letter dated January 21, 2021, DEQ notified Boise Cascade Wood Products of its preliminary determination that their Elgin facility would likely be required to install Selective Catalytic Reduction on Boilers 1 and 2. Boise Cascade provided DEQ a technical memo dated April 19, 2021 in which Boise Cascade's consultant concluded that SCR was not technically feasible on boilers at the Elgin facility.

NPS Comment: The Boise Cascade letter reiterated several concerns from its initial submittal:

- SCR is not identified in the EPA RBLC database as an existing control technology deployed on biomass-fired industrial boilers.
- The temperatures of boiler flue-gas exiting the Facility's Dry Electrostatic Precipitator (DESP) are generally below the minimum SCR operating temperature and well below the optimum operating temperatures for catalyzed reactions.
- Flue-gas reheating would be required for effective SCR operation, which would result in additional energy usage and GHG emissions.
- The presence of alkali metals and other constituents found in wood could poison catalysts.
- There is risk of ammonia slip, oxidation of CO to CO_2, and formation of sulfuric acid mist emissions associated with injection of ammonia.

As a point of reference, we can share that SCR has been applied to biomass-fired boilers located downstream of the particulate control device with reheating. The excerpt below illustrating this is from the New Hampshire draft Regional Haze SIP:

> **Burgess BioPower**: The biomass unit at this facility was subject to NNSR for NO_x at the time of their initial permitting; hence, the NO_x limit was established as the LAER[1] based limit. The NO_x limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NO_x/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for SO_2 at the time of its initial permitting in 2010; hence, the SO_2 limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. SO_2/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the SO_2 BACT. Sorbent injection was installed for acid gas control but is not used to control SO_2 emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs SO_2/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the emission limit for SO_2. For this reason, NHDES has determined that the current limits for the above facilities represent the "most effective use of control technologies" for NO_x and SO_2. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

[1] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NO_x. While two recent determinations for similar facilities in Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

The presence of catalyst poisons should be evaluated by stack testing instead of relying upon speculation. Ammonia slip should not be an issue with SCR and acid mist emissions would not be a concern with this very-low-sulfur fuel. Any hazard associated with handling and storage of ammonia can be addressed with proper training, operation, and maintenance.

Boise Cascade provided a Technical Memorandum from Maul Foster Alongi—their findings are summarized below:

- There are no applications of SCR controls on a wood-fired boiler that are comparable in size to Facility boilers.
- SCR controls have not been implemented on load-following boilers.
- SCR controls have not been implemented on primarily bark-fired boilers.
- SCR controls have not been implemented on any wood-fired boilers in Oregon.
- Oregon soils often have higher concentrations of metals that are catalyst poisons than other locations where SCR has been implemented. These metals are accumulated in the wood burned in the boilers
- The average flue-gas temperature following the Facility's DESP is less than the typical operating temperature for SCR and well below the optimal temperature range for catalytic reduction.
- For the reasons described above, SCR was determined to not be technically feasible for the Facility's wood-fired boilers.

The temperature (reheat) and poisoning (stack test) concerns raised are addressed in the New Hampshire RH SIP excerpt above. While SCR has not been applied to comparably-sized, load-following, bark-fired boilers it certainly may be possible and we encourage ODEQ to thoroughly explore this potential.

ODEQ:

Boise Cascade also provided DEQ a second technical memo dated May 10, 2021, in which a vendor provided their recommendations regarding the feasibility and effectiveness of other NO_x reduction technologies including low oxygen operation, air staging, flue gas recirculation natural gas co-firing, and steam or water injection.

Rather than install SCR, Boise Cascade chose an alternative compliance option to accept federally enforceable requirements to install and continually operate combustion controls, monitoring equipment and accept emission limitations to reduce round II regional haze pollutants from the Elgin facility. On August 12, 2021, Boise Cascade entered into a stipulated agreement and order with DEQ. The final order, included in Appendix E, requires the following and contains other requirements and provisions:

- *On and after July 31, 2022, the permittee's PSELs for SO_2 are 17.1 tons/year*
- *Within three months of the signed order, permittee shall install a Continuous Emission Monitoring System on Boiler 1 and Boiler 2 to measure NO_x emissions.*
- *By July 31, 2023, the permittee shall begin installation of combustion improvement project(s) designed to achieve emissions reductions of NO_x from Boiler 1 and Boiler*

2 by 15%, and permittee shall begin monitoring NO_x emissions using the CEMS to determine actual NO_x emission reductions achieved by controls.

- *If initial boiler combustion improvement project(s) fail to achieve a minimum 15% NO_x reduction, the permittee may implement additional combustion improvement projects to achieve 15% NO_x reduction or accept PSEL reductions.*
- *By December 31, 2025, the permittee shall submit 12 months of CEMS data to DEQ demonstrating the NO_x emission reductions achieved by combustion controls, and shall propose a NO_x limit based on the achieved reductions.*
- *If combustion controls fail to achieve 15% NO_x reduction, the permittee must reduce PSEL (PM_{10}+NO_x+SO_2) to a level that would achieve a Q/d commensurate with a 15% Boiler NO_x reduction.*
- *On and after March 31, 2026, the permittee must comply with emission limits and the PSEL established under the conditions listed in the order.*

NPS Comment: Boise Cascade also provided a report by CPL Combustion & Control Systems (CPL) in which it says "…CPL determined SCR was not technically feasible for control of NO_x from the Facility's boiler system…" The CPL report (excerpted below) does not appear to address EPA's requirements for a technical infeasibility demonstration:

> The technical difficulties described above apply generally to biomass boilers. Advanced technologies and auxiliary heating of the tail-end flue gas have been developed recently in an attempt to overcome these difficulties. However, the wide load swings experienced by plywood mill boilers result in unstable exhaust temperatures and would make it particularly difficult to control the flue gas temperature and reagent injection rate needed to ensure appropriate NO_x reductions while avoiding excessive ammonia slip. For these reasons, SCR technology has not been successfully demonstrated for a load-following spreader-stoker boiler with load swings comparable.

Modern control systems are likely capable of overcoming the difficulties described by CPL. We recommend that Boise Cascade provide an analysis of technical feasibility from an established SCR vendor.

3.2.2 Boise Cascade-Elgin SCR analyses

NPS Comments:

We have questions regarding the Boise Cascade-Elgin analyses for addition of SCR.

<u>Retrofit Factor</u>

Analyses assumed a retrofit factor of 1.5 for all woodwaste boilers. The EPA Control Cost Manual (CCM) recommends that site-specific retrofit factors (greater than the 1.0 default value) should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book <u>Estimating Costs of Air Pollution Control</u>. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The CCM also addresses "Retrofit Cost Considerations" in section 2.6.4.2. In the absence of such an analysis standard practice is to assume a retrofit factor = 1.0, which represents a 30% increase above costs for a "greenfield" project.

SCR Equipment Life

Boise Cascade analyses assumed a 20-year life for these boilers. We used the CCM default of 25 years in our calculations (EPA CCM).

Chemical Engineering Plant Cost Index (CEPCI)

Boise Cascade analyses used a 2019 CEPCI = 603.1. We used the recommended CEPCI = 607.5 (EPA CCM).

Interest Rate

Boise Cascade analyses used a 4.75% interest rate. We used the CCM recommended current bank prime rate = 3.25% (EPA CCM).

Operating Costs

Boise Cascade analyses overestimated the operating costs of SCR (and SNCR) by substituting values for "Total operating time for the SCR (t_{op})" and "Total NO_x removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. We participated in the EPA work group that developed the CCM workbooks for NO_x (and SO_2) controls and advise that values in the "Design Parameters" spreadsheet should be generated from the "Data Inputs" spreadsheet and the algorithms that operate on them according to the methods and equations described in the CCM.

The "Total operating time for the SCR (t_{op})" parameter is not meant to be the actual operating time for the control device, which was entered directly into the "Design Parameters" spreadsheet. Instead, it represents a method to adjust capacity utilization to actual (or permitted) utilization based upon a fraction (Total System Capacity Factor (CF_{total}) applied to the maximum capacity. This issue was compounded by also over-riding the calculation of Total NO_x removed per year to reflect percent removed from the PSEL or actual conditions instead of percent removed from the emissions that would have resulted from hours of operation.

The basic parameters (on the "Data Inputs" spreadsheet) that define emissions and control costs are:

- maximum heat input rate (QB)
- higher heating value (HHV) of the fuel
- estimated actual annual fuel consumption
- net plant heat input rate (NPHR)
- Number of days the SCR (or SNCR) operates (t_{SCR} or t_{SNCR})
- Number of days the boiler operates (t_{plant})
- Inlet NO_x Emissions (NO_{xin}) to SCR (or SNCR)
- Outlet NO_x Emissions (NO_{xout}) from SCR (or SNCR)

All but “estimated actual annual fuel consumption” are essentially fixed by the boiler, fuel, and control device characteristics. The “Number of days the SCR operates (tSCR)” typically equals “Number of days the boiler operates (tplant).”[2] We adjusted “estimated actual annual fuel consumption” to yield the uncontrolled emissions specified by the Boise Cascade Elgin analysis.

For example, rather than the actual operating time for the control device, “total operating time for the SCR (t_{op})” parameter represents a method to adjust capacity utilization to actual utilization based upon a fraction (Total System Capacity Factor (CF_{total}) applied to the maximum capacity. For the Power Boiler (PSEL), the Boise Cascade Elgin workbook correctly calculated the Total System Capacity Factor = 0.976 but overrode that result by entering 8,760 hours for Total operating time for the SCR instead of the value of 8,550 hours that would have been calculated by the spreadsheet. The workbook then calculated annual operating costs as if the SCR were operating at maximum capacity 8,760 hours instead of 8,550 hours. This was compounded by also overriding the calculation of Total NO_x removed per year to reflect 90% removed from the PSEL (90% * 170 tpy) instead of 90% removed from the emissions (153 tpy) that would have resulted from the 8,760 hours of operation (90% * 153 tpy).

Property taxes were included in several analyses prepared for Boise Cascade Elgin. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment so they were excluded from NPS estimates.

CPL presented information on two gas re-heat options for addition of SCR: regenerative heating or natural gas heating. According to CPL:

> In order to raise the flue gas to temperatures high enough for the SCRs to work, over 11.0 MMBtu/hr. of natural gas would be used to re-heat the flue gas just to get the SCR system to work.

We applied the CCM workbook and adjusted the “estimated actual annual fuel consumption” to yield the uncontrolled emissions (170 ton/yr) specified. Although reheat costs were not included in the facility analysis, we used the CPL estimate (11 mmBtu/hr) and the July 2021 EIA Oregon industrial natural gas price ($5.16) in our cost estimate calculations (see Table 1).

Table 1. Boise Cascade Wood Products, LLC - Elgin Complex

SCR	**Company/Consultant Estimates**	**NPS Estimates**
Unit	PB #1 & #2	PB #1 & #2
Total Annual Cost	$ 1,450,706	$ 1,340,205
Emissions Reduction (tpy)	152	153
Cost-Effectiveness ($/ton)	$ 9,538	$ 8,777

[2] In March 2021, EPA revised the SNCR workbook to include an entry for the “Number of days the boiler operates (tplant).” Until that revision, the SNCR workbook assumed 365 days of plant operation.

3.2.3 NPS Results & Conclusions for Boise Cascade-Elgin

Addition of SCR to Power Boilers #1 & #2 would reduce NO_x emissions by 153 ton/yr and is well below the Oregon cost threshold.

3.3 Georgia Pacific Wauna Mill

3.3.1 Summary of NPS GP Wauna Review

From the draft SIP, ODEQ:

Georgia Pacific chose an alternative compliance option to accept a federally enforceable requirement to install controls and associated monitoring equipment, and to accept emission limitations to reduce round II regional haze pollutants from the Wauna facility. On August 9, 2021 Georgia Pacific entered a stipulated agreement and order with DEQ. The order is included in Appendix E. The order requires the following and contains other requirements and provisions:

- *On August 1, 2022 PSELs are: PM_{10} = 1,077 tons/year; NO_x = 2,019 tons/year; SO_2 = 913 tons/year.*
- *On December 31, 2024, PSELs are PM_{10} = 1,077 tons, NO_x = 1,999 tons, and SO_2 = 913 tons.*
- *On July 31, 2026, PSELs are PM_{10} = 1,077 tons, NO_x = 1,413 tons, and SO_2 = 913 tons.*
- *For the Paper Machine 5 Yankee Burner, by December 31, 2024, permittee shall replace existing Yankee burner with a Low NO_x Burner achieving <= 0.03 lb/MMBtu.*
- *For the TAD1 and TAD 2 burners on Paper Machines 6 and 7, permittee shall have a NO_x emission rate no greater than 0.06 Ib/MMBtu and shall use this emission rate for PSEL compliance.*
- *For Power Boiler - 33, by December 31, 2022, permittee shall meet with DEQ to discuss the technical details of the low NO_x burner, flue gas recirculation, and CEMS installation to determine what permitting permittee shall need prior to construction.*
- *As expeditiously as practicable, but not later than July 31, 2026, permittee shall install low NO_x burners and flue gas recirculation in order to achieve an emission rate no greater than 0.09 Ib/MMBtu on a seven-day rolling basis.*
- *Within one year of completing the Power Boiler project, but not later than July 31, 2026, permittee shall install a CEMS to measure the emissions of NO_x from Power Boiler - 33.*
- *Upon DEQ's approval of the CEMS certification, permittee shall use data collected from the CEMS to demonstrate compliance with the applicable NO_x PSEL.*

NPS Comments:

Based upon information submitted by GP, actual Power Boiler NO_x emissions are 266 tpy (@ 0.465 lb/mmBtu) and the proposed 0.09 lb/mmBtu NO_x emission rate represents an 81%

reduction (215 tpy). As shown below in Table 2, addition of SCR is highly cost-effective and would reduce actual emissions by 240 tpy.

Table 2. GP -Wauna Power Boiler

SCR	**Company/Consultant Estimates**		**NPS Estimates**	
Unit	Pwr Blr (PSEL)	Pwr Blr (actual)	Pwr Blr (PSEL)	Pwr Blr (actual)
Current Emission Rate (lb/mmBtu)	0.341	0.465	0.341,	0.341
Current Emissions (tpy)	589	266	589	266
Controlled Emission Rate (lb/mmBtu)	0.034	0.046	0.034	0.047
Emission Reduction (tpy)	532	239	530	240
Total Annual Cost	$ 4,444,671	$ 2,942,622	$ 854,578	$ 719,058
Cost-Effectiveness ($/ton)	$ 8,353	$ 12,317	$ 1,612	$ 3,002

Although GP submitted cost-effectiveness estimates for the biomass-fired Fluidized Bed Boiler (FBB), the draft SIP does not discuss controlling this boiler. GP included costs for reheating the FBB SCR inlet gas stream with no explanation of how this cost was derived. Still, we accepted the estimate of reheat cost see the attached workbooks for calculations. Instead of GPs estimated cost-effectiveness of $15,069/ton, we estimate a Total Annual Cost of $1.4 million = $9,051/ton for addition of SCR to remove 155 ton/yr of NO_x (see Table 3).

Table 3. GP-Wauna Fluidized Bed Boiler

SCR	**Company/Consultant Estimates**		**NPS Estimates**	
Unit	FBB (PSEL)	FBB (actual)	FBB (PSEL)	FBB (actual)
Current Emission Rate (lb/mmBtu)	0.256	0.467	0.256	0.467
Current Emissions (tpy)	224	171	224	172
Controlled Emission Rate (lb/mmBtu)	0.026	0.047	0.026	0.0467
Emissions Reduction (tpy)	202	153	202	155
Total Annual Cost	$ 3,043,381	$ 3,222,435	$ 1,982,073	$ 1,416,263
Cost-Effectiveness ($/ton)	$ 15,069	$ 21,000	$ 9,823	$ 9,165

3.3.2 NPS Results & Conclusions for GP-Wauna

- We recommend that ODEQ's draft SIP more thoroughly address emissions from GP Wauna by including an analysis of emissions from the Fluidized Bed Boiler.
- The safety and health concerns expressed by ODEQ relative to adding SCR to the Power Boiler can be addressed by proper operation and maintenance. The water, wastewater concerns are not relevant to SCR. Electricity and natural gas costs were included in the cost-effectiveness analyses.
- Addition of SCR to the Power Boiler and the Fluidized Bed Boiler is much less expensive than estimated by GP, and its cost effectiveness is within the ODEQ threshold under PSEL or actual operating conditions.

- Addition of SCR to these two boilers could reduce NO_x emissions by 732 tons/yr under PSEL conditions or 395 tons/yr under actual conditions. Instead, ODEQ's proposal would reduce the PSEL by 606 tpy and actual emissions by 215 tpy.

3.4 Georgia Pacific Toledo Mill

3.4.1 Summary of NPS GP Toledo Review

ODEQ:

In a letter to DEQ dated April 30, 2021, Georgia Pacific stated concerns with installing SCR or SNCR on the power boilers based on undesirable associated effects such as health exposure and safety risk of handling and storing aqueous ammonia, ammonia slip, increased water usage and subsequent wastewater disposal, and higher electricity and natural gas use.

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

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

If Permittee chooses to complete a NO_x reduction project:

- *By July 31, 2026, Permittee shall install low NO_x burners and flue gas recirculation on EU-11, EU-13, and EU-18 in order to achieve an emission rate no greater than 0.09 lb/MMBtu on a seven day rolling basis.*
- *As expeditiously as practicable, but not later than July 31, 2026, install a CEMS to measure the emissions of NO_x from EU-11, EU-13, and EU-18.*

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

- *PSELs for Round 2 regional haze pollutants incorporated in the Permit for the replacement shall be no more than the potential to emit of the replacement, or a Q of 889 tons per year of NO_x, 437 tons per year of SO_2, and 311 tons per year of PM_{10}, whichever is lower.*
- *Complete the replacement of the EU-11, EU-13, and EU-18 with new technology no later than July 31, 2031.*

NPS Comments:

Based upon information submitted by GP, actual power boiler NO_x emissions are 436 tpy and the proposed 0.09 lb/mmBtu NO_x emission rate represents 64% reduction (280 tpy). As shown below, addition of SCR is highly cost-effective and would reduce actual emissions by 394 tpy (see Tables 4–6).

Table 4. GP-Toledo Power Boiler #1 (EU-13)

SCR	**Company/Consultant Estimates**		**NPS Estimates**	
Unit	#1 Pwr Blr (PSEL)	#1 Pwr Blr (actuals)	#1 Pwr Blr (PSEL)	#1 Pwr Blr (actuals)
Current Emission Rate (lb/mmBtu)	0.271	0.28	0.271	0.28
Current Emissions (tpy)	224	150	223	150
Controlled Emission Rate (lb/mmBtu)	0.0270	0.028	0.027	0.028
Emissions Reduction (tpy)	201	135	200	135
Total Annual Cost	$ 1,736,111	$ 1,713,128	$ 403,086	$ 376,519
Cost-Effectiveness ($/ton)	$ 8,623	$ 12,681	$ 2,012	$ 2,782

Table 5. GP-Toledo Power Boiler #3 (EU-18)

SCR	**Company/Consultant Estimates**		**NPS Air Resources Division Estimates**	
Unit	#3 Pwr Blr (PSEL)	#3 Pwr Blr (actuals)	#3 Pwr Blr (PSEL)	#3 Pwr Blr (actuals)
Current Emission Rate (lb/mmBtu)	0.16	0.164	0.16	0.164
Current Emissions (tpy)	108	76	107	76
Controlled Emission Rate (lb/mmBtu)	0.0160	0.0164	0.016	0.016
Emissions Reduction (tpy)	97	68	97	68
Total Annual Cost	$ 1,314,983	$ 1,296,647	$ 344,165	$ 326,507
Cost-Effectiveness ($/ton)	$ 13,579	$ 19,057	$ 3,560	$ 4,796

Table 6. GP-Toledo Hog Fuel Boiler #4 (EU-11)

SCR	**Company/Consultant Estimates**		**NPS Air Resources Division Estimates**	
Unit	#4 Hog Fuel Blr (PSEL)	#4 Hog Fuel Blr (actuals)	#4 Hog Fuel Blr (PSEL)	#4 Hog Fuel Blr (actuals)
Current Emission Rate (lb/mmBtu)	0.168	0.28	0.168	0.28
Current Emissions (tpy)	218	211	218	212
Controlled Emission Rate (lb/mmBtu)	0.0168	0.0280	0.017	0.028
Emissions Reduction (tpy)	197	190	197	190
Total Annual Cost	$ 2,175,317	$ 2,307,306	$ 551,522	$ 514,046
Cost-Effectiveness ($/ton)	$ 11,067	$ 12,173	$ 2,802	$ 2,699

3.4.2 NPS Results & Conclusions for GP-Toledo

- The safety and health concerns expressed by ODEQ relative to adding SCR to the Power Boiler can be addressed by proper operation and maintenance. The water, wastewater concerns are not relevant to SCR. Electricity and natural gas costs were included in the cost-effectiveness analyses.
- Addition of SCR to the power boilers is much less expensive than estimated by GP and its cost-effectiveness is within the ODEQ threshold under PSEL or actual operating conditions.
- Addition of SCR to these three boilers could reduce NO_x emissions by 495 tons/yr under PSEL conditions or 393 tons/yr under actual conditions. Instead, ODEQ's proposal would reduce the PSEL by 297 tpy and actual emissions by 280 tpy.

3.5 International Paper-Springfield Mill

3.5.1 Summary of NPS IP-Springfield Review

From the draft SIP, ODEQ:

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

On August 9, 2021, International Paper entered a stipulated agreement and order with DEQ and LRAPA, included in Appendix E. The order requires the following and contains other requirements and provisions:

- *On and after July 31, 2022, the Permittee' s combined assigned PSELs for the Power Boiler, Package Boiler, Lime Kilns and Recovery Furnace for the following pollutants are:237 tons per year for SO_2, as a 12-month rolling average; 962 tons per year for NO_x, as a 12-month rolling average; 177 tons per year for PMl0, as a 12-month rolling average.*
- *the only fuel that it may combust in the Power Boiler and Package Boiler is natural gas, except that it may operate the Power Boiler and Package Boiler on ultra-low sulfur dieselfor no more than 48 hours per year and when needed for natural gas curtailments.*
- *the only fuels that it may combust in the Recovery Furnace are Black Liquor Solids and natural gas, except that it may operate the Recovery Furnace on ultra-low sulfur diesel no more than 48 hours per year and when needed for natural gas curtailment.*
- *the only fuels that it may combust in the Lime Kilns are natural gas, product turpentine and product methanol, except that it may operate the Lime Kilns on ultra-low sulfur diesel no more than 48 hours per year and when needed for natural gas curtailment.*
- *By December 31, 2022, International Paper shall install CEMS and measure the emissions of NO_x from the Power Boiler and use data collected from the CEMS to demonstrate compliance with the NO_x emissions rates*

- *Ensure that the CEMS are certified by DEQ and LRAPA no later than May 31, 2023.*
- *On and after January 31, 2025, International Paper shall meet the following emission limit: a 0.25 lb NO_x/MMBtu on a 7-day rolling average from the Power Boiler.*
- *On and after December 31, 2025, the Permittee's assigned PSEL for the following pollutants and Emission Unit is: 179 tons per year for NO_x, as a 12-month rolling average for the Power Boiler.*

NPS Comments:

We recommend that ODEQ document its rationale for modifying its initial proposal to require SCR on the Power Boiler. Information provided by IP and its consultant indicate that actual annual NO_x emissions from the Power Boiler are 140 ton/yr @ 0.22 lb/mmBtu and its PSEL is 873.74 ton/yr. The ODEQ proposal may allow short-term NO_x emissions to increase while 12-month rolling average emissions would decrease by 39 tons.

IP overestimated capital and operating costs of applying SCR to the Power Boiler and the Package Boiler. The resulting Total Annual Cost of $2.9 million for the Power Boiler (actuals) contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unsupported retrofit factor. A 4.75% interest rate was used instead of the current bank prime rate = 3.25% as recommended by the CCM. Operating costs were overestimated due to over-riding of the "Total operating time" and "Total NO_x removed per year" parameters.[3] Reagent costs were overestimated by more than an order of magnitude. We request more information explaining the need to reheat the SCR inlet gas stream as we did not include reheat costs in our analysis. IP's estimated cost-effectiveness is $22,924/ton. We estimate a Total Annual Cost of $0.9 million = $6,971/ton for addition of SCR to remove 127 ton/yr of NO_x.

We request the same additional information for the Power Boiler and the Package Boiler. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions. The cost-effectiveness of adding SCR falls below the ODEQ threshold of $10,000/ton for the PSEL cases for both boilers, and for the Power Boiler under actual conditions. The cost effectiveness of adding SCR for the Package Boiler clearly exceeds the ODEQ threshold under actual conditions (see Tables 7-8).

3 IP overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR (top)" and "Total NO_x removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the Power Boiler (actuals), IP's workbook calculated the Total System Capacity Factor = 0.268 but over-rode that result by entering 8,424 hours for Total operating time for the SCR instead of the value of 2,348 hours that would have been calculated by the spreadsheet. As a result, the workbook calculates annual operating costs as if the SCR were operating at maximum capacity 8,424 hours/yr instead of 2,348 hours. This error was compounded by over-riding the calculation of "Total NO_x removed per year" to reflect 90% removed from the 2017 actual emissions (90% * 140 tpy) instead of 90% removed from the emissions (504 tpy) that would have resulted from the 8,424 hours of operation (90% * 504 tpy). Instead, we adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified.

Table 7. IP-Springfield Power Boiler (EU-150A)

SCR	Company/Consultant Estimates		NPS Estimates	
Unit	IP Springfield PB (PSEL)	IP Springfield PB (actuals)	IP Springfield PB (PSEL)	IP Springfield PB (actuals)
Current Emission Rate (lb/mmBtu)	0.46	0.22	0.46	0.22
Current Emissions (tpy)	874	140	874	141
Controlled Emission Rate (lb/mmBtu)	0.046	0.022	0.046	0.022
Emissions Reduction (tpy)	786	126	786	127
Total Annual Cost	$ 3,621,820	$ 2,895,491	$ 321,562	$ 160,145
Cost-Effectiveness ($/ton)	$ 4,606	$ 22,924	$ 1,122	$ 6,971

Table 8. IP-Springfield Package Boiler

SCR	Company/Consultant Estimates		NPS Estimates	
Unit	IP Springfield PkgBlr (PSEL)	IP Springfield PkgBlr (actuals)	IP Springfield PkgBlr (PSEL)	IP Springfield PkgBlr (actuals)
Current Emission Rate (lb/mmBtu)	0.20	0.07	0.2	0.07
Current Emissions (tpy)	298	1	298	1
Controlled Emission Rate (lb/mmBtu)	0.020	0.007	0.020	0.007
Emissions Reduction (tpy)	268	1	268	1
Total Annual Cost	$ 2,130,423	$ 825,603	$ 882,460	$ 882,460
Cost-Effectiveness ($/ton)	$ 7,948	$ 655,241	$ 3,292	$ 698,725

3.5.2 NPS Results & Conclusions for **IP-Springfield**

- Addition of SCR to the Power Boiler and Package Boiler is much less expensive than the calculations estimated by IP, and its cost-effectiveness is within the ODEQ threshold under PSEL operating conditions.
- Addition of SCR to the Power Boiler is much less expensive than estimated by IP, and its cost-effectiveness is within the ODEQ threshold under actual operating conditions.
- Addition of SCR to the Package Boiler would exceed the ODEQ threshold under actual operating conditions.
- Addition of SCR to the Power Boiler could reduce NO_x emissions by 1,054 tons/yr under PSEL conditions or 127 tons/yr under actual conditions; this would represent an additional 88 ton/yr of actual NO_x reduction compared to the ODEQ proposal.

3.6 Cascade Pacific Pulp Halsey Pulp Mill

3.6.1 Summary of NPS Cascade Pacific Pulp Halsey Pulp Mill Review

From the draft SIP, ODEQ:

In a letter dated January 21, 2021, ODEQ notified CPP of its preliminary determination that their Halsey facility would likely be required to install LNB/Flue Gas Recirculation on their Power boiler #1, and switch to Ultra Low Sulfur Diesel instead of #6 fuel oil as an emergency backup fuel on site.

On August 9, 2021, Cascade Pacific entered a stipulated agreement and order with DEQ, included in Appendix E, that requires the following and contains other requirements and provisions:

- *The permittee not combust fuel oil #6 at any emission unit in the facility by June 30, 2024.*
- *By January 31, 2022, conduct source testing for NO_x at Power Boiler #1.*
- *By December 31, 2022, finalize design of low NO_x burner to be installed on Power Boiler #1, with objective to achieve 33% reduction is NO_x emissions.*
- *By December 31, 2023, construct and install the low NO_x burner at Power Boiler #1.*
- *By June 30, 2024, submit a report to DEQ with analysis of source test data and a proposal for revised PSELs, to be incorporated into the permittees' permit by modification or at next renewal.*

NPS Comments:

ODEQ's proposed 33% NO_x reduction is not enforceable and is less than the 64% NO_x reduction evaluated by Cascade Pacific Pulp for Low-NO_x Burners. Based upon information submitted by CPP, actual Power Boiler #1 NO_x emissions are 53 tpy (@ 0.22 lb/mmBtu) and the proposed 33% reduction would reduce emissions by 18 ton/yr. Current NO_x emissions from Power Boiler #2 are 6 ton/yr and were not addressed.

CPP has overestimated capital and operating costs of applying SCR to the power boilers (PB#1 & #2). The resulting Total Annual Cost of $1.8 million for PB#1 contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unsupported retrofit factor. Operating costs were overestimated by more than a factor of two due to over-riding of the "Total operating time" and "Total NO_x removed per year" parameters.[4] Reagent costs were overestimated by more than an order of magnitude. Finally, an explanation is needed

4 CPP also overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR (top)" and "Total NO_x removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the PB#1 (actuals), the workbook correctly calculated the Total System Capacity Factor = 0.232 but over-rode that result by entering 8,622 hours for Total operating time for the SCR instead of the value of 2,032 hours that would have been calculated by the spreadsheet. CPP then allowed the workbook to calculate annual operating costs as if the SCR were operating 8,622 hours instead of 2,032 hours. This error was compounded by over-riding by also over-riding the calculation of "Total NO_x removed per year." Instead, we adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified.

to understand the necessity of reheating the SCR inlet gas stream. We did not include reheat costs in our analysis. CPP's estimated cost-effectiveness is $38,292/ton. We estimated a Total Annual Cost of $0.4 million = $8,276/ton for addition of SCR to remove 48 ton/yr of NO_x. The same issues apply to PB#1 at PSEL conditions as well as PB#2.

We applied the SCR CCM workbook to PB#1 & #2 for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the ODEQ threshold of $10,000/ton for the PSEL cases for both boilers. Addition of SCR to PB#1 under actual conditions is below the ODEQ threshold. The cost effectiveness of adding SCR for PB#2 clearly exceeds the ODEQ threshold under actual conditions (see Tables 9-10).

Table 9. CPP-Halsey Power Boiler #1

SCR	**Company/Consultant Analysis**		**NPS Analysis**	
Unit	#1 PB (PSEL)	#1 PB (actual)	#1 PB (PSEL)	#1 PB (actual)
Current Emission Rate (lb/mmBtu)	0.28	0.22	0.276	0.221
Current Emissions (tpy)	133	53	134	54
Controlled Emission Rate (lb/mmBtu)	0.026	0.022	0.028	0.022
Emissions Reduction (tpy)	119	48	121	48
Total Annual Cost	$ 1,911,460	$ 1,826,543	$ 425,353	$ 400,430
Cost-Effectiveness ($/ton)	$ 16,029	$ 38,292	$ 3,523	$ 8,276

Table 10. CPP-Halsey Power Boiler #2

SCR	Company/Consultant Analysis		NPS Analysis	
Unit	#2 PB (PSEL)	#2 PB (actual)	#2 PB (PSEL)	#2 PB (actual)
Current Emission Rate (lb/mmBtu)	0.28	0.18	0.28	0.181
Current Emissions (tpy)	75	6	76	6
Controlled Emission Rate (lb/mmBtu)	0.028	0.018	0.028	0.018
Emissions Reduction (tpy)	68	5	68	5
Total Annual Cost	$1,916,103	$1,028,580	$ 404,952	$ 363,869
Cost-Effectiveness ($/ton)	$ 28,349	$ 204,083	$ 5,926	$ 66,534

3.6.2 NPS Results & Conclusions for CPP-Halsey

- The cost-effectiveness of adding SCR is within the ODEQ threshold of $10,000/ton for the PSEL cases for both boilers.
- Addition of SCR to PB#1 under actual conditions is within the ODEQ threshold. Addition of SCR to this boiler could reduce NO_x emissions by 121 tons/yr under PSEL conditions or 48 tons/yr under actual conditions.
- The cost effectiveness of adding SCR for PB#2 clearly exceeds the ODEQ threshold under actual conditions.

3.7 Gas Transmission Northwest LLC - Compressor Stations 12 & 13

From the draft SIP, Regarding Compressor Station 12, ODEQ:

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

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

NPS Comment: ODEQ could improve the SIP by describing how actual emissions will be affected by these permit changes. Because Q/d based on recent emissions was low (2.33), we support this approach for addressing potential future emission increases.

From the draft SIP, Regarding Compressor Station 13, ODEQ:

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

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

NPS Comment:

We agree with ODEQ that SCR is the most rigorous, cost-effective NO_x control technology available for Compressor Station 13, which is located 14km from Crater Lake National Park.

3.8 Biomass One, L.P.

The Biomass One White City plant is located in Jackson County, Oregon, approximately 9 miles north of Medford, OR. The facility has two boilers, designated "North Boiler" and "South

Boiler," as well as a small space heater, various storage piles, and additional insignificant sources. The two boilers are essentially identical in design and permitted throughput. The boilers combust wood products as fuel, with natural gas used for startup periods.

The boilers currently use multicyclone collectors followed by dry electrostatic precipitators (ESPs) for control of PM_{10}, and the PM_{10} emissions from the storage piles are controlled using wet suppression. NO_x is controlled in both boilers using a combustion technique known as staged combustion. There are no SO_2 controls on either boiler.

The North and South boilers were evaluated for NO_x controls in the four-factor analysis. The analysis concluded that addition of SCR could reduce the North boiler's NO_x emissions by 118 tons at a cost of $14,131/ton and the South boiler's NO_x emissions by 149 tons at a cost of $11,100/ton. Some of the parameters used in the four-factor analysis (such as the interest rate and remaining useful life) overestimated costs. Our calculations estimated costs of $7,200/ton NO_x removed for both boilers using the company's analysis methods, which is within the state's threshold of $10,000/ton.

According to the Public Draft SIP, ODEQ notified Biomass One in January 2021 that it had made a preliminary determination that their facility would likely be required to install SCR on both boilers. However, in August DEQ entered into an agreement with Biomass One that does not require SCR installation. The stipulated agreement includes the following provisions:

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

NPS Comment:

SCR on the North and South boilers is cost effective and technically feasible. DEQ's response to our comments on Biomass One does not address the technical feasibility or cost effectiveness of SCR, and the discussion in section 3.7.5.14 of the Public Draft SIP does not support the decision not to require it. An alternative emissions reduction plan should provide equivalent emissions reductions, but the agreement does not guarantee that any NO_x emissions reductions will occur in the future. This may result in a lost opportunity to reduce emissions by up to 260 tons per year. We request that DEQ require either installation of SCR or a commensurate level of NO_x emissions reduction within a specified timeframe.

3.9 Roseburg Forest Products Co.

Roseburg Forest Products Co. (RFP) owns and operates a wood products manufacturing complex in Dillard, Oregon that produces lumber, plywood, and particleboard. There are three stoker boilers with auxiliary sanderdust and natural gas burners that combust hogged fuel, sanderdust, natural gas, or a combination thereof to produce steam that is used for cogeneration.

NPS Comment:

According to the Public Draft SIP, ODEQ's preliminary determination was that installation of SNCR would be cost-effective on the three boilers, but ultimately determined to enter into a stipulated agreement and order with RFP instead. The agreement requires the facility to meet specified emissions limits by June 30, 2025 through boiler optimization or by installing SNCR. These alternative methods for NO_x reduction should result in roughly equivalent levels of emissions reductions, and we agree with ODEQ's decision to require these reductions.

Section 3.7.5.15 of the public draft SIP discusses the agreement signed with RFP and shows several of the requirements. We recommend including this additional provision in the discussion in Section 3.7.5.15 for clarity:

> On and after June 30, 2025, Permittee shall meet the following emission limits:
>
> - 0.27 lb NOx/MMBtu on a 7-day rolling average at Boiler 1;
> - 0.26 lb NOx/MMBtu on a 7-day rolling average at Boiler 2;
> - 0.26 lb NOx/MMBtu on a 7-day rolling average at Boiler 6; Or
> - Average of emissions from Boiler 1, Boiler 2, and Boiler 6 of 0.25 lb
> - NOx/MMBtu (7-day rolling average).

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November 1, 2021

VIA E-MAIL

Oregon DEQ
Attn: Karen F. Williams
700 NE Multnomah St., Room 600
Portland, OR 97232-410
RHSIP2021@deq.state.or.us

Re: **Comments on Oregon DEQ's Proposed Regional Haze State Implementation Plan for 2018-2028**

To Whom It May Concern:

Beveridge & Diamond, P.C. submits these comments on behalf of Gas Transmission Northwest LLC ("GTN") regarding the Oregon Department of Environmental Quality's ("DEQ") proposed amendments to the Regional Haze State Implementation Plan ("draft SIP").[1] The proposed rule, subject to Environmental Quality Commission adoption, would amend Oregon's SIP with submittal of the 2018–2028 Regional Haze Plan to the Environmental Protection Agency ("EPA").

Provided below are detailed comments on DEQ's draft SIP.

A. DEQ Should Reconsider Measuring "Reasonable Progress" Via PSEL Reductions.

In Round II of its Regional Haze planning, DEQ sought to capture 80% of Q for major (Title V) sources. When using 2017 Plant Site Emission Limits ("PSELs") to calculate Q, DEQ captured 80% of Q by setting a threshold of Q/d at 5.00. However, calculating Q based on PSELs did not capture the correct 80% of sources for purposes of real-world contributions to visibility impairment in Class I areas.

In its initial screening analysis, DEQ calculated a facility's Q (as part of the Q/d) by using the facility's 2017 PSEL. All facilities with a Q/d over 5.00 were required to conduct a four-factor analysis. However, "[i]f a facility's actual emissions were below the screening

[1] Public comments are due on November 1, 2021. *See* Notice of Proposed Rulemaking at https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/RHSIP2021pnp2.pdf.

threshold and potential emissions above the screening threshold, DEQ provided the source an opportunity to reduce [PSELs] to a point where Q/d would be less than 5.00."[2] If a facility accepted a PSEL reduction to this point, DEQ did not require it to conduct further analysis or implement control technologies

DEQ viewed a Q/d (based on PSELs) as some of "the strongest evidence that emissions from facilities contribute to visibility impairment."[3] But actual emissions, not PSELs, are more accurate both in (1) measuring a source's current contribution to regional haze and (2) evaluating whether reductions will result in "reasonable progress" as required by EPA regulations. *See* 40 C.F.R. § 51.308 (d)(1) ("[T]he State must establish goals . . . that provide for reasonable progress towards achieving natural visibility conditions.").

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

Q/ds calculated by using PSELs can be misleading, as certain sources with relatively higher Q/ds are minimal contributors to regional haze because their actual emissions are very low.[4] Measuring emissions by relying on reductions in PSELs may artificially represent "reasonable progress" because a source's actual emissions may not change upon a PSEL reduction.

EPA's guidance does not support using PSELs to calculate Q/d. EPA's 2019 Guidance states that "[a] state may use a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts . . . ."[5] Read in context, "annual emissions" refers to *actual* emissions rather than potential emissions (i.e., PSELs). EPA's preference for using actual emissions, rather than PSELs, is further supported by EPA's July 2021 clarification memorandum.[6]

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[2] DEP'T OF EVNTL. QUALITY, OREGON REGIONAL HAZE STATE IMPLEMENTATION PLAN: FOR THE PERIOD 2018–2028, at 35 (Aug. 27, 2021) (hereinafter OREGON REGIONAL HAZE DRAFT SIP).
[3] *Id.* at 38.
[4] GTN's compressor stations simply need an inflated PSEL to maintain operational flexibility and maintain pipeline compression.
[5] GUIDANCE ON REGIONAL HAZE STATE IMPLEMENTATION PLANS FOR THE SECOND IMPLEMENTATION PERIOD 20 (Aug. 20, 2019) (hereinafter 2019 GUIDANCE).
[6] CLARIFICATIONS REGARDING REGIONAL HAZE STATE IMPLEMENTATION PLANS FOR THE SECOND IMPLEMENTATION PERIOD 12 (July 8, 2021) (noting that an approach is to perform four-factor analyses "using recent historical utilization or production levels as the baseline").

The draft SIP's justification for using PSELs in the Q/d analysis cites the following portion of the 2019 EPA Guidance:

> "If a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its [long term strategy (LTS)] in the SIP. . . . The LTS can be said to include those controls only if the SIP includes emission limits or other measures (with associated averaging periods and other compliance program elements) that effectively require the use of the controls."[7]

Because PSELs *are* already enforceable emissions limits, the 2019 Guidance does not support the proposition that DEQ cites it for.

Lastly, using actual emissions, rather than PSEL, would have imposed no additional costs on DEQ. DEQ had data regarding facilities' actual emissions. DEQ should have used the more accurate metric in evaluating key contributors to regional haze and prioritizing actual emissions reductions at those sources.

B. DEQ's Use of PSEL in Its Screening Analysis Was Inconsistent.

In DEQ's initial screen analysis, DEQ allowed a facility to reduce its PSEL such that if its Q/d was less than 5.00, then the facility would "screen out," and DEQ would not require that the facility conduct a four-factor analysis or implement control technologies. However, certain emission sources, such as GTN's compressor stations, were precluded from reducing their PSELs in order to account for worst-case natural gas demand scenarios as required by the Federal Energy Regulatory Commission ("FERC") certification process. DEQ should clarify whether it evaluated other methods or opportunities for facilities to screen out of the requirement of completing four-factor analyses.

For facilities that did not (or could not) reduce their PSELs, DEQ required they conduct four-factor analyses. After receiving these analyses, DEQ adjusted and evaluated them, and then put each source into one of three "bins."[8]

- Bin 1. Likely cost-effective candidates. Control devices with cost less than $10,000/ton, or those that appear to be technically feasible but for which no cost analysis was provided.

[7] OREGON REGIONAL HAZE DRAFT SIP, at 66 (quoting 2019 GUIDANCE, at 43).
[8] GTN's comments regarding DEQ's methodology for adjusting cost-effective controls are discussed below. *See infra* Section D.

- Bin 2. Retain for further analysis. Control devices with cost more than $10,000/ton but less than $30,000/ton.
- Bin 3. Cost is unlikely to be reasonable.[[9]] Above $30,000/ton.[10]

Aside from allowing PSEL reductions to initially screen out such that a facility's Q/d was below 5.00 (and a four-factor analysis was therefore not required), DEQ never permitted a facility to reduce PSEL as part of its four-factor analysis or in subsequent analysis (e.g., evaluating a control technology's cost effectiveness).

C. DEQ Should Provide Greater Clarity in the "Criteria" It Used to Measure Cost Effectiveness.

DEQ did not provide adequate documentation of its process in creating criteria and evaluating entities' cost-effectiveness analyses. The draft SIP notes that DEQ worked "in consultation with EPA and other states" to develop criteria to assess cost effectiveness.[11] DEQ used these criteria to assess "presumed cost-effectiveness of pollution controls."[12] DEQ also used these criteria to evaluate facilities' cost-effectiveness analyses and additional information that facilities submitted with their cost-effectiveness analyses.[13]

DEQ's vague explanation is insufficient. DEQ should:

(1) Clarify whether it also consulted with EPA at this step;[14]
(2) Clarify what criteria were identified;
(3) Clarify how those criteria were applied;
(4) Clarify what "presumed cost-effectiveness" means, and how "presumed cost-effectiveness" was developed and applied.

D. DEQ Should Provide Greater Clarity on How It "Adjusted" Cost-Effectiveness Analyses.

DEQ adjusted parties' cost-effectiveness analyses, but provided limited to no information regarding how it adjusted these analyses.

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[9] The draft SIP states that DEQ did not adjust a facility's analysis "for consistency among emissions units" if a facility's submittal exceeded $30,000/ton for a control technology. OREGON REGIONAL HAZE DRAFT SIP, at 35. DEQ should clarify the analysis it undertook, if any, for these submittals.
[10] *Id.*
[11] *Id.* at 26.
[12] *Id.* at 35.
[13] *Id.* at 26–27.
[14] *Compare id*. at 26 ("EPA and other states"), *with id.* at 35 (only states).

1. *Initial Review*

The draft SIP notes that, after DEQ received facilities' initial cost-effectiveness analyses it adjusted those analyses "for basic factors," listing PSEL, interest rate, and useful life.[15] It is unclear whether PSEL, interest rate, and useful life represents an exhaustive list or whether DEQ adjusted parties' submittals for other factors. However, based upon DEQ records, it appears that adjustments were not so limited and that DEQ staff were given the green light to make "additional adjustments . . . over and above the 'basic adjustments.'"[16] DEQ should clarify the scope of adjustments DEQ staff were permitted to make, ideally by identifying the entire spectrum of cost categories that DEQ staff adjusted.

The draft SIP does not indicate what deference, if any, DEQ gave to parties' facility-specific estimates (e.g., vendor quotes) for certain costs or factors in their cost-effectiveness analyses and in DEQ's adjustment of those costs. EPA's Control Cost Manual identifies facility-specific information as the most accurate type of information when evaluating the cost of controls.[17] DEQ should clarify how it evaluated these facility-specific cost estimates and state whether it developed criteria for evaluating parties' facility-specific information.

2. *Subsequent Review*

After identifying control technologies at seventeen facilities, DEQ required additional cost-effectiveness information from these sources. DEQ then "reviewed the additional cost estimate information and sent facilities letters notifying them of DEQ's decisions about the cost effectiveness of controls."[18]

DEQ should clarify its "review" at this stage. As evidenced between parties' submittals and DEQ's decisions, DEQ also adjusted parties' cost-effectiveness submittals in this second review. DEQ should clarify its process for revising parties' submittals—e.g., whether it developed criteria for revisions and, if so, DEQ should provide information regarding those criteria.

Lastly, DEQ should clarify the level of deference it gave, if any, to parties' facility-specific estimates for certain cost items or factors in this second review. DEQ should also clarify whether it developed criteria for evaluating parties' facility-specific information in this second review.

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15 *Id*. at 35.
16 Email from Joe Westersund, DEQ, to Yuki Puram, DEQ (July 13, 2020).
17 *See, e.g.*, CONTROL COST MANUAL SECTION 1 - CHAPTER 2 - COST ESTIMATION: CONCEPTS AND METHODOLOGY 7-8 (2017), https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
18 OREGON REGIONAL HAZE DRAFT SIP, at 36.

E. DEQ Should Correct Certain Mischaracterizations of GTN in the Draft SIP.

Certain references to GTN in the draft SIP, in comments submitted by the National Park Service ("NPS"), are inconsistent and erroneous. For example, NPS asserts that GTN did not use EPA's most recent Control Cost Manual in analyzing Selective Catalytic Reduction ("SCR") as applied to its compressor stations. Incorrect. GTN relied extensively on the 7th Edition of the Control Cost Manual. For example, the Control Cost Manual states that for industrial application of SCR (i.e., not a large electric generating unit) the useful life is 20 to 25 years.[19] Accordingly, GTN used the Control Cost Manual to estimate the useful life of SCR as applied to its compressor station natural gas turbines. Furthermore, the Control Cost Manual acknowledges the preference for site-specific information for cost estimates. To the extent possible, GTN submitted site-specific information in support of its cost estimates.

NPS makes various other assertions regarding GTN, including that a 75% control efficiency for SCR is low, that GTN inflated administrative costs, and that a 30-year useful life for SCR should be used (see above). Incorrect. GTN correctly applied EPA's Control Cost Manual in submitting its four-factor analysis and in calculating the cost effectiveness of SCR as applied to its turbines.

Ultimately, NPS's comments grossly underestimated the cost per ton of NOx removed at GTN's facilities. Using PSELs, NPS estimated that the cost per ton of NOx removed was $1,833 (Unit 12A), $3,801 (12B), $4,074 (13C), and $3,887 (13D). Using reduced fuel consumption scenarios, NPS estimated that the cost per ton was still less than $10,000/ton. However, NPS did not provide its cost estimates in this scenario.

GTN submitted cost-effectiveness analyses for its compressor station units, analyses consistent with the Control Cost Manual, which showed retrofit application of SCR on these units was not cost effective based on DEQ's $10,000/ton threshold. GTN's cost estimate was based on facility-specific information where possible.

[19] CONTROL COST MANUAL SECTION 7 - CHAPTER 2 - SELECTIVE CATALYTIC REDUCTION § 2.4.2 (2019), https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

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Thank you for your consideration of these comments. If you or your colleagues have questions about this comment or require additional information, feel free to contact me at (206) 315-4811 or dweber@bdlaw.com.

Regards,

David C. Weber

cc: Jill Holley, jill_holley@tcenergy.com
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November 1, 2021

Oregon Department of Environmental Quality
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BY EMAIL TO: RHSIP2021@deq.state.or.us
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RE: **Public Comment on Regional Haze State Implementation Plan by Environmental Justice Advocates**

Dear Director Whitman, DEQ staff, and members of the Environmental Quality Commission,

On behalf of the undersigned organizations, we respectfully submit these comments on the aspects of Oregon's Regional Haze State Implementation Plan ("SIP") pertaining to the regulation of stationary sources that collectively contribute 80% of Oregon's regional haze-forming emissions.

Introduction and Background

The EPA's Regional Haze program is aimed at improving air quality in national parks and wilderness areas designated as Class I under the Clean Air Act.[1] By reining in visibility-impairing pollution, the Regional Haze program also delivers important public health protections to neighboring communities.[2]

[1] Oregon is home to a dozen Class I protected public lands for which this program is designed to restore clean and clear skies: Crater Lake National Park, Diamond Peak Wilderness, Eagle Cap Wilderness, Gearhart Mountain Wilderness, Hells Canyon Wilderness, Kalmiopsis Wilderness, Mountain Lakes Wilderness, Mount Hood Wilderness, Mount Jefferson Wilderness, Mount Washington Wilderness, Strawberry Mountain Wilderness, and Three Sisters Wilderness.

[2] While the Regional Haze program implicates major and minor sources of pollution as well as mobile sources and area sources, our comments are focused on the Title V stationary sources that collectively contribute 80% of

Oregon's proposed rules to implement the Regional Haze program gave DEQ powerful tools to reduce pollution. Many of the undersigned organizations submitted comments in support of these strong rules.[3] The Q/d screening mechanism resulted in 32 of Oregon's biggest polluters performing four-factor analyses, and the $10,000 cost-effectiveness threshold laid the groundwork for DEQ to be able to order 17 of these sources to install controls that would have improved visibility and protected public health. DEQ sent these facilities "control letters" reflecting DEQ's decision as to which cost-effective control they would likely be required to install, based on the agency's four-factor analysis.[4]

However, after comments on the Division 223 rules were closed, DEQ fundamentally altered its approach without engaging in any kind of public process and without consulting stakeholders other than the regulated entities. Instead of ordering all 17 facilities to implement the reasonable progress controls identified through four-factor analyses, DEQ inexplicably chose to extend offers that allowed all but one of these facilities to exit the program or comply with the program without investing in the highly effective pollution-reducing technology that DEQ could—and should—have required these facilities to install to meet the state's obligations under the regional haze program.

Ultimately, DEQ only unilaterally ordered ***one*** of the 32 facilities that completed four-factor analyses to install reasonable progress controls. One facility, EVRAZ, voluntarily agreed to implement the reasonable progress control identified in DEQ's control letter. For the other 15 facilities that identified cost-effective controls, DEQ allowed them to voluntarily reduce their Plant Site Emission Limits (PSELs)—the high pollution limits contained in Oregon's air permits—or voluntarily take other less effective emissions-reducing steps instead of installing the reasonable progress controls DEQ indicated it would require them to install based on their four-factor analyses.

Notably, DEQ's consultation with the Federal Land Managers, including National Park Service, happened before DEQ executed these back-room agreements. Given the significance of this change in direction, there is a real question as to whether DEQ has satisfied the requirement to consult with Federal Land Managers no less than 60 days prior to a public hearing or public comment opportunity. See 40 CFR 51.308(i). The purpose of this requirement is to allow Federal Land Managers to offer their recommendations on the proposed strategies to address visibility impairment; consultation that happens before a major, unannounced change in strategy is not meaningful consultation. We agree with the National Parks Service's comments on ten facilities' cost analyses and urge DEQ to adopt and require the reasonable progress controls identified by the Park Service in the revised SIP. *See* SIP at App'x G.

The result is that Oregon's Regional Haze program will not deliver the community and public land-benefitting emissions reductions that the rules should have delivered and that advocates expected.

Oregon's emissions of visibility impairing pollutants (NO2, SO2, and PM). *See* Notice of Rulemaking, https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/RHSIP2021pnp2.pdf at 5 (laying out primary elements of Oregon's long-term strategy).

[3] *See* DEQ, Regional Haze 2021, Staff Report (July 22, 2021), https://www.oregon.gov/deq/EQCdocs/072321_ItemJ_RegionalHaze.pdf at 39 (noting comments from Cully Air Action Team (CAAT), Earthjustice, Friends of the Columbia Gorge, Green Energy Institute (GEI), Oregon Environmental Council (OEC), National Parks Conservation Association (NPCA), Neighbors for Clean Air, Northwest Environmental Defense Center (NEDC), Verde).

[4] The control letters are available on DEQ's website. *See* DEQ, Facilities Conducting Four Factor Analysis, https://www.oregon.gov/deq/aq/Pages/haze-ffa.aspx.

For the 15 facilities that DEQ allowed to exit the program, ordering the facility to install pollution controls identified in the facility's four-factor analysis would have resulted in greater emissions reductions than will be achieved by the back-room agreements. *See infra* § I(B). Indeed, all but one of the off-ramp agreements with defined new PSELs allow facilities to continue emitting at levels ***above*** their 2017 emissions, which DEQ used as a baseline. In other words, those agreements will not result in ***any*** reductions from the baseline emissions level. *Id.*

Nothing in Oregon's rules allows DEQ to offer alternative compliance options that result in less effective emissions reduction measures, and nothing requires the agency to offer alternative compliance options at all. Oregon's newly adopted Regional Haze rules specify that "DEQ may, but is not required to, offer alternative compliance" to sources required to submit a four-factor analysis by entering into "a stipulated agreement and final order" under which a source agrees to either accept PSEL limits to bring the source's emissions below the threshold for inclusion in the Regional Haze program, take other steps to reduce emissions equivalent to the emissions reductions from installation of reasonable progress controls identified in the source's four-factor analysis, or replace their emissions units. OAR 340-223-0110(2).

The only rationale DEQ offered for this choice is that the agency offered these off-ramps to facilities with actual emissions that would exclude them from the program if the threshold for inclusion in the program were based on the facility's actual 2017 emissions rather than their 2017 permitted emissions limits. *See* SIP at 35. This appears to be an after-the-fact attempt to rewrite the rules to change the screening threshold for inclusion in the Regional Haze program from a threshold based on permit limits—a threshold that brought 32 facilities into the program—to one based on actual emissions—a threshold that would have left out 18 of those facilities—without undergoing public scrutiny and comment on this approach. Eight of the facilities to which DEQ offered alternative compliance would still have been included in the program even if the threshold were based on their actual emissions rather than permit limits.[5] DEQ's rationale for this choice simply does not explain DEQ's actions.

Moreover, nothing in the SIP suggests that DEQ analyzed whether the "alternative compliance" agreements that required emissions reduction measures different from the ones identified in DEQ's control letters provide equivalent reductions or studied the impact of these agreements on Oregon's Regional Haze strategy. Nothing in the SIP attempts to justify the off-ramping of 15 facilities by reference to any requirements of the Regional Haze program.

The modeling in Oregon's SIP shows that if DEQ had ordered all 17 facilities that identified cost-effective controls in their four-factor analyses to install those controls, Oregon would be on or below the glidepath for some—but not all—of the Class I areas. *See* SIP at 75. In other words, Oregon's Regional Haze strategy depends on taking steps DEQ has chosen not to take, plus other emissions reductions. By allowing 15 out of 17 facilities with cost-effective controls to satisfy their Regional Haze obligations by taking steps that reduce emissions less than installing reasonable progress controls would, Oregon has already undermined its own compliance strategy.

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[5] *See* Table 3-6, SIP at 45 (showing actual Q/d > 5.00 for Owens-Brockway Glass Container, Gilchrist Forest Products, Boise Cascade Wood – Elgin Complex, Georgia Pacific – Wauna Mill, Cascade Pacific Pulp – Halsey Pulp Mill, International Paper – Springfield, Georgia-Pacific – Toledo, Roseburg Forest Products – Dillard); Appendix E (Stipulated Agreements and Final Orders for all eight facilities).

DEQ's decision to allow some of Oregon's largest stationary sources of haze-forming pollution to reduce the overhead in their air permits instead of installing pollution controls that satisfy a four-factor reasonable progress analysis violates the Clean Air Act and federal Regional Haze rules.

It is also an abrogation of Oregon's duty to its environmental justice communities. By allowing 15 facilities to avoid reducing their emissions at all or to take less effective emissions reduction steps, Oregon has prioritized the interests of the regulated entities over the interests of those facilities' neighbors whose health and well-being are threatened by NOx, SO2, and PM and who would have benefitted from more effective controls.

In Section I, we demonstrate that Oregon's decision to offer almost every facility with reasonable progress controls available "alternative compliance" instead of installing those controls undermines Oregon's ability to reduce air pollution and make reasonable progress towards the goal of natural conditions and violates the Regional Haze requirements. Section I(B) contains a table comparing the emissions reductions that would have resulted from ordering facilities to install cost-effective controls identified in their four-factor analyses versus those that will result (if any) from the measures in the "alternative compliance" agreements.

In Section II, we explain that, even assuming that there are circumstances in which it would be permissible under the Regional Haze rules to off-ramp facilities instead of ordering them to install reasonable progress controls, Oregon has failed to adequately justify its decision. Oregon's modeling to demonstrate how the SIP relates to Oregon's reasonable progress goals is based on the assumption that facilities would install and operate the specific controls identified in DEQ's control letters based on the facilities' four-factor analyses. DEQ cannot satisfy the Regional Haze program's requirements without analyzing the effect of these back-room agreements and comparing the emissions reductions from the agreements to the emissions reductions from reasonable progress controls. Oregon has not used an appropriate framework for exempting facilities from the requirement to install reasonable progress controls and instead selected the measures in the alternative agreements that in most cases reflected business as usual.

In Section III, we unpack how DEQ's decision to offer "alternative compliance" to 15 facilities flies in the face of Oregon's commitment to environmental justice. The back-room process through which DEQ entered these agreements, without any community input or oversight, cannot be reconciled with DEQ's definition of environmental justice: "the fair and meaningful involvement" of affected communities. Nor do the substance of these agreements serve communities.

I. OREGON'S DECISION TO EXEMPT STATIONARY SOURCES FROM THE REQUIREMENT TO INSTALL REASONABLE PROGRESS CONTROLS VIOLATES REGIONAL HAZE REQUIREMENTS.

Oregon's proposed SIP fundamentally fails to meet Clean Air Act and Federal Regional Haze Rule requirements because it relies on impermissible backroom agreements that allow some of the largest haze-producing sources in the state to avoid federal regional haze requirements, undercutting the emission reductions necessary for the state to make reasonable progress towards visibility improvement goals.

A. Regional Haze Requirements

The Clean Air Act establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I federal areas which impairment results from manmade air pollution." 42 U.S.C. § 7491(a)(1). To advance this goal, the Clean Air Act and EPA's implementing regulations (the Regional Haze Rule) direct Oregon, and all states, to periodically revise their state implementation plan ("SIP") to make incremental "reasonable progress" toward eliminating human-caused visibility impairment in Class I federal areas by 2064. 40 C.F.R. 51.308(f).

In developing a SIP, a state must:

- Calculate progress to date on improving air quality in Class I areas and the Uniform Rate of Progress;
- Develop a long-term strategy for addressing regional haze by evaluating the four factors under the Clean Air Act four factors to determine what emission limits and other measures are necessary to make reasonable progress towards the visibility goal;
- Conduct regional-scale modeling of projected future emissions under the long-term strategy to establish reasonable progress goals and then compare those goals to the Uniform Rate of Progress line; and
- Adopt a monitoring strategy and other measures to track future progress and ensure compliance.

82 Fed. Reg. 3078, 3091 (Jan. 10, 2017).

The Clean Air Act requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. States may not subsequently reject measures they previously deemed reasonable. *See infra* § I(C). EPA's 2017 Regional Haze Rule Amendments made clear that states must first conduct the required four-factor analysis for its sources, and then use the results from its four-factor analyses and determinations to develop the reasonable progress goals. The key determinant of whether a state is satisfying its Regional Haze obligations is whether a state's strategy is based on the four statutory factors. A state must consider the four factors regardless of where any Class I area is on the glidepath. *See infra* § I(D) (explaining that the Uniform Rate of Progress is not a "safe harbor").

A state's SIP must be supported by a reasoned analysis and include a description of the criteria the state used to determine which sources or groups of sources it evaluated and how the four statutory factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. *See* 42 U.S.C. § 7491(g)(1); 40 C.F.R. 51.308(f)(2)(i). The state must document the technical basis for the SIP, and include that information in the plan when they make it available for public comment.

The long-term strategy is a core component of the SIP operating as means through which a state ensures that its reasonable progress goals will be met. As part of the process for developing the long-term strategy, the Regional Haze Rule explicitly directs states to determine reasonable progress by using the four factors listed in the Clean Air Act—costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of the source—to analyze control options for identified haze-polluting sources (known as the four-factor analysis). 40 C.F.R. 51.308(f)(2). This analysis is important because it identifies the level of control sources need to achieve for Oregon to make reasonable progress towards the state's visibility goal, which are the emission reduction measures that become part of the state's long-term strategy. *Id*. The Regional Haze Rule is clear that in establishing a long-term strategy for regional haze, states must:

> [E]valuate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment….[I]nclude in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.

40 C.F.R. 51.308(f)(2)(i).

A state's SIP must also meet consultation requirements. The state is required to draft the SIP in consultation with the Federal Land Managers of the Class I national parks and wilderness areas affected by the state's haze-pollution to ensure that it improves air quality in those areas and document how the state addressed comments provided by Federal Land Managers. *See* 40 CFR 51.308.

It is the state's duty to demonstrate that reasonable progress requirements are met. While a state may request information and analysis from regulated sources, and importantly collaborates with its regional planning organization throughout the haze planning process, the state is ultimately accountable for preparing, adopting, and submitting a compliant SIP to EPA.

B. <u>The Backroom Agreements Result in Substantially Less Reduction in Emissions Than Would Be Achieved By Installing Reasonable Progress Controls.</u>

The "alternative compliance" options that DEQ extended to 15 of the 17 facilities that identified cost-effective controls all result in far fewer emissions reductions than would be achieved if those sources were required to install the reasonable progress controls identified in their four-factor analyses. Of the agreements with reduced PSELs, all but one allow sources to continue emitting at levels above their 2017 actual emissions levels, which DEQ used as the baseline for the SIP.[6] In other words, the agreements for the sources with agreements containing defined PSELs will not result in *any emissions reductions*—and could even result in *increased* emissions—from the 2017 baseline DEQ used to develop the SIP.

The following table reflects a comparison between the emissions reductions from each facility's actual 2017 emissions that would result from ordering the 17 facilities to install the reasonable progress controls identified through a four-factor analysis and reflected in DEQ's control letter versus the emissions reductions (if any) that will result from the provisions of their "alternative compliance" agreements.[7]

[6] The following entities accepted "alternative compliance" consisting of reduced PSELs that are still above their 2017 actual emissions: Boise Cascade Wood Products – Elgin, 31-0006; Georgia Pacific – Wauna Mill, 04-0004; Boise Cascade Wood Products – Medford, 15-0004; Gas Transmission Northwest – Compressor Station 12, 09-0084; International Paper – Springfield, 208850; Georgia Pacific – Toledo, 21-0005 (for the option to replace boilers, minimum PSELs SO2 and PM10 are above 2017 emission levels); Northwest Pipeline – Baker Compressor Station, 01-0038; Northwest Pipeline – Oregon City Compressor Station, 03-2729; and Willamette Falls Paper Company, 03-2145. The only entity that accepted reduced PSELs that were actually below its 2017 emissions level was Owens-Brockway, but as explained below, because it is now operating only one of the two furnaces it was operating in 2017, the new, reduced PSELs are unlikely to result in significant actual emissions reductions.

[7] Joe Kordzi, an environmental engineering consultant with three decades of experience at EPA Region 6, performed the technical analysis reflected in these comments. 2017 actual emissions data obtained from Appendix A and Table

The table does not reflect a perfect one to one comparison because of the variability in the conditions contained in the agreements. For example, some of the agreements lack defined PSELs[8] and some contain multiple possible compliance options, such as installing a control device, changing a fuel source, reducing actual emissions by a certain percentage, ceasing operations, or accepting a reduced PSEL, or some combination thereof.[9]

When an "alternative compliance" agreement included PSEL reductions, the new PSELs were subtracted from the facility's 2017 actual emissions baseline to determine if the agreement resulted in any actual reductions. Negative values in the Alternative Compliance NOx Reduction, SO2 Reduction, or PM10 Reduction columns indicate that the agreement allows the facility to emit at levels higher than the 2017 baseline emissions. In these cases, the agreement will not result in real emissions reductions, and could even result in increased emissions relative to 2017.

When an "alternative compliance" agreement specified that permit limits would be reduced multiple times, the Alternative Compliance NOx Reduction, SO2 Reduction, and PM10 Reduction columns of the table reflect the emissions reductions from the final and greatest PSEL reduction.

When an "alternative compliance" agreement included several compliance options, one of which was PSEL reductions, the columns for Alternative Compliance NOx Reduction, SO2 Reduction, and PM10 Reduction reflect reductions from the PSELs rather than the alternatives.

The total reductions listed at the bottom of the table do not reflect all possible reductions from installation of reasonable progress controls or "alternative compliance" agreements because of data limitations.

In the "Installation of Cost-Effective Control from Four-Factor Analysis" columns, the total reductions do not include reductions from Gilchrist Forest Products, 18-0005, because no "control letter" is available for this facility, so it is unclear what reasonable progress control DEQ would have ordered it to install based on the facility's four-factor analysis. The SIP suggests that DEQ indicated it would require Gilchrist to install Selective Noncatalytic Reduction on boilers B-1 and B-2, which the facility did not think would be technically feasible. *See* SIP at 51.

3-2 in SIP; Stipulated Agreements and Final Orders obtained from Appendix E to SIP; control letters obtained from DEQ website, https://www.oregon.gov/deq/aq/Pages/haze-ffa.aspx. The control efficiencies used to determine emission reductions from the emissions baseline are those reflected in the four-factor analyses except with the exception that Selective Catalytic Reduction efficiencies were assumed to be 95% in all cases, which is a conservative estimate for gas-fired boilers, or unless otherwise specified.

[8] The following facilities' agreements lack defined annual PSELs: Boise Cascade Wood Products – Medford, 15-0004 (uses a combined total PSEL instead of definite limits for each individual Regional Haze pollutant); EVRAZ, 26-1865 (requires PSELs to be based on performance testing); Cascade Pacific – Halsey Pulp Mill, 22-3501 (same); Gilchrist Forest Products, 18-0005 (same); Roseburg Forest Products – Dillard, 10-0025 (contains emissions limits based on 7-day rolling averages).

[9] The following facilities' agreements contained multiple compliance options: Northwest Pipeline – Baker Compressor Station, 01-0038; Biomass One, 15-0159; Boise Cascade – Elgin, 31-0006; Georgia Pacific – Toledo, 21-0005; Northwest Pipeline – Oregon City Compressor Station, 03-2729.

In the “Requirements of Alternative Compliance Agreements” columns, the total reductions do not include all potential reductions from facilities where those reductions could not be quantified, which include:

- JELD-WEN, 18-0006—DEQ has not yet executed any agreement with the facility, though the SIP indicates that it intends to do so and will include the agreement in the final version of the SIP to be submitted to EPA.
- Boise Cascade Wood Products, LLC - Elgin Complex, 31-0006— the agreement totals include emissions reductions from the revised SO_2 PSELs in the “alternative compliance” provisions, but do not include any reductions from the provisions requiring installation of unspecified combustion controls on Boilers 1 and 2.
- Georgia Pacific - Wauna Mill, 04-0004—the agreement totals include emissions reductions from the revised PSELs in the “alternative compliance” provisions, rather than any reductions from the provisions requiring installation of Low NO_x Burners on Paper Machine 5 and Power Boiler 33, which are unknown.
- International Paper – Springfield, 208850—the agreement totals reflect the 2022 reduced PSELs for NO_x, PM_{10} and SO_2 for the Power Boiler, Package Boiler, Lime Kilns, and Recovery Furnace, but not the unknown reductions by 2025 from fuel limitations and NO_x emission limits for the Power Boiler.
- Roseburg Forest Products – Dillard, 10-0025—the agreement totals do not reflect any reductions from Roseburg Forest Products because the reductions from the gradual reduction of NO_x 7-day rolling average emission limits on Boilers 1, 2, 6 could not be quantified and the agreement did not specify a control.
- International Paper – Springfield, 208850—the agreement totals reflect only reductions from initial reduced PSELs and not later fuel limitations and PSEL reductions for Power Boiler, which could not be quantified.

TABLE: Emission Reductions from 2017 Emissions Levels — Comparison of Reductions from Installation of Cost-Effective Controls and Reductions from "Alternative Compliance" Agreements

		INSTALLATION OF COST-EFFECTIVE CONTROL FROM FOUR-FACTOR ANALYSIS (Reductions measured from 2017 actual emissions)				**REQUIREMENTS OF "ALTERNATIVE COMPLIANCE" AGREEMENT** (Reductions measured from 2017 actual emissions)				
Facility ID	**Facility Name**	**Cost-Effective Control Identified in DEQ Control Letter**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Agreement Requirement**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Notes**
26-1876	Owens-Brockway Glass Container Inc.	Ceramic Catalytic Filter on A-Furnace and D-Furnace	356.4	106.1	48.4	Reduce PSELs effective July 31, 2025	266.7	10.1	21.2	
18-0005	Gilchrist Forest Products	No control letter available				Install Electro-Static Precipitator			52.0	Unknown what cost-effective control DEQ would have ordered
31-0006	Boise Cascade Wood Products, LLC - Elgin Complex	Selective Catalytic Reduction on two biomass boilers	119.7			PSEL for SO_2 only of 17.1 tons beginning 7/31/22. Install combustion controls in Boilers 1 and 2 by 12/31/24. If NOx not reduced by 15%, reduce PSEL by 15% by 3/31/26.		-4.1		Unknown what combustion controls would be installed under Agreement or what effect they would have on NOx emissions. Agreement reductions based on SO2 PSEL only.
04-0004	Georgia Pacific - Wauna Mill	Low NOx Burner on Paper Machines 1, 2, 5, 6, 7; Low NOx Burner on No. 21 Lime Kiln; Selective Catalytic Reduction on No. 33 Power Boiler	494.2			Reduce PSEL for NOx, PM10, and SO_2 by 8/31/26; Low NOx Burner on Paper Machine 5 by 12/31/24; Low NOx Burner on Power Boiler 33 by 7/31/26	-375.3	-373.2	-301.2	Unknown what effect Low NOx Burners in agreement will have on actual emissions

		INSTALLATION OF COST-EFFECTIVE CONTROL FROM FOUR-FACTOR ANALYSIS (Reductions measured from 2017 actual emissions)				REQUIREMENTS OF "ALTERNATIVE COMPLIANCE" AGREEMENT (Reductions measured from 2017 actual emissions)				
Facility ID	**Facility Name**	**Cost-Effective Control Identified in DEQ Control Letter**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Agreement Requirement**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Notes**
22-3501	Cascade Pacific Pulp, LLC - Halsey Pulp Mill	End #6 fuel oil; Low NOx Burner/Flue Gas Recirculation on Power Boiler No. 1 with assumed efficiency of 64%	33.9			End #6 fuel oil by facility by 6/30/24 and Low NOx Burner on Power Boiler 1 by 12/31/23 with assumed efficiency of 33% and unspecified future NOx limits	17.5			Unknown what impact eliminating No. 6 fuel oil will have
15-0004	Boise Cascade Wood Products, LLC - Medford	Selective Catalytic Reduction on three boilers	99.8			Unspecified reduction in NOx, PM10, or SO_2 such that Q=302 tons by 8/1/26	-48.3			Assumed PSEL reduction all in the form of NOx reduction
09-0084	Gas Transmission Northwest LLC - Compressor Station 12	Selective Catalytic Reduction on A and B gas turbines	42.2			Reduce PSEL for NOx, PM10 and SO_2 by 8/1/25	-73.8	-1.8	-4.3	
208850	International Paper - Springfield	Selective Catalytic Reduction on Power Boiler	133.0			PSELs for NOx, PM10 and SO_2 for only the Power Boiler, Package Boiler, Lime Kilns, and Recovery Furnace as specified by 7/31/22; fuel limitations and NOx limit and 179 ton NOx PSEL for Power Boiler only by 12/31/25	-238.0	-169.4	4.4	Reductions from agreement based on PSELs; cannot evaluate effect of later fuel limitations and PSEL reductions for Power Boiler

		INSTALLATION OF COST-EFFECTIVE CONTROL FROM FOUR-FACTOR ANALYSIS (Reductions measured from 2017 actual emissions)				REQUIREMENTS OF "ALTERNATIVE COMPLIANCE" AGREEMENT (Reductions measured from 2017 actual emissions)				
Facility ID	**Facility Name**	**Cost-Effective Control Identified in DEQ Control Letter**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Agreement Requirement**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Notes**
21-0005	Georgia-Pacific – Toledo LLC	Selective Noncatalytic Reduction on No. 3 Boiler; Selective Catalytic Reduction for Nos. 1 & 4 Boilers; Low NOx Burner for Nos. 1, 2 & 3 Lime Kilns; Baghouse for chip handling	424.4		24.7	(1) Low NOx Burner and Flue Gas Recirculation on Nos. 1, 3, and 4 Boilers by 7/31/26 or (2) replace by 7/31/31 and meet minimum PSEL	50.1	-420.9	-115.2	Reductions from agreement based on minimum PSEL
01-0038	Northwest Pipeline LLC - Baker Compressor Station	Low Emission Control on C1, C2, C3, and C4 RICEs (80% control)	125.7			(1) PSEL for NOx, PM10 and SO_2 by 8/1/26 or (2) replace RICEs with Q of replaced RICEs $\leq$ 201 (total PSEL not specified)	-34.5	-0.1	-3.0	Reductions from agreement based on minimum PSEL
03-2729	Northwest Pipeline LLC - Oregon City Compressor Station	Low Emission Control on EU1 RICEs 1 & 2 (80% control)	123.2			Replace EU1 RICEs 1 & 2 and meet NSPS; PSEL of replaced RICEs $\leq$ 219 (total PSEL not specified)	-65.0			Agreement NOx reduction based on 2017 actuals for the two RICEs minus the Agreement PSEL for replaced RICEs of 219
15-0159	Biomass One, L.P.	Selective Catalytic Reduction on North and South Boilers	282.2			(1) Cease operation by 1/1/27 or (2) install Selective Catalytic Reduction on North and South Boilers or (3) demo SCR is infeasible. If (3) then unspecified NOx controls.				Cannot determine Agreement NOx reductions due to options and unspecified potential NOx controls if SCR infeasible

		INSTALLATION OF COST-EFFECTIVE CONTROL FROM FOUR-FACTOR ANALYSIS (Reductions measured from 2017 actual emissions)				REQUIREMENTS OF "ALTERNATIVE COMPLIANCE" AGREEMENT (Reductions measured from 2017 actual emissions)				
Facility ID	**Facility Name**	**Cost-Effective Control Identified in DEQ Control Letter**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Agreement Requirement**	**NOx Reduction (tons)**	**SO_2 Reduction (tons)**	**PM10 Reduction (tons)**	**Notes**
10-0025	Roseburg Forest Products - Dillard	SNCR on Boilers 1, 2 and 6 (25% control)	236.6			Gradual reduction of NOx 7-day rolling average emission limits on Boilers 1, 2, 6 from 1/31/23–6/30/25				Effect of agreement on NOx totals cannot be determined because agreement does not require a particular control; 7-day average emission limits in agreement could be achievable through SNCR or combustion controls
18-0006	JELD-WEN	Selective Noncatalytic Reduction on wood-fired boiler	20.1							No agreement executed at time of technical analysis
03-2145	Willamette Falls Paper Company	Low NOx Burner on Boilers 1 & 2	70.7			PSEL for NOx, PM10, and SO_2 by 8/1/22; Boilers 1, 2, and 3 only burn gas and ULSD for 48 hrs/yr	-53.9	-2.3	-5.0	Reductions from agreement based on minimum PSEL
Total reductions[10]			**2,562.1**	**106.1**	**73.1**		**-554.5**	**-961.7**	**-351.1**	

[10] Total reductions do not reflect all possible reductions from installation of reasonable progress controls or "alternative compliance" agreements. Please see preceding explanation of limitations on calculation of total reductions.

This comparison between the emissions reductions from installation of cost-effective controls identified in facilities' four-factor analyses and the reductions expected from the measures in the "alternative compliance" agreement demonstrates several things:

- In almost every instance, a facility's "alternative compliance" agreement resulted in demonstrably lower emission reductions than would have been achieved by installing controls identified in the facility's four-factor analysis. This was true even in some cases where the four-factor analysis and agreement called for the same control. For example, for Cascade Pacific Pulp – Halsey Pulp Mill, both the four-factor analysis and agreement called for a Low NOx Burner on Boiler 1 and elimination of number 6 fuel oil. However, the four-factor analysis evaluated the Low NOx Burner at an efficiency of 64% while the agreement required an efficiency of 33%.

- With the exception of Owens-Brockway, in every case in which the agreement contained a reduced PSEL or offered a reduced PSEL as an optional alternative to installing a particular control, subtracting the new PSEL from the facility's actual 2017 baseline emissions resulted in negative values. This means the agreement will not only result in no real emissions reductions, but also allows the emissions to increase over the 2017 baseline value.

- The Owens-Brockway facility merits particular attention. While the reduced PSELs in the facility's "alternative compliance" agreement appear at first glance to represent real emission reductions, those reductions are based on a 2017 baseline, when the facility was operating two glass furnaces—Furnace A and Furnace D. Earlier this year in connection with an enforcement action, DEQ ordered Owens-Brockway to retire Furnace A, a condition which is reiterated in the "alternative compliance" agreement. In its Regional Haze control letter, DEQ listed the NOx, SO2, and PM10 PSELs for Furnace D to be 123, 70, and 20 tons, respectively. The Agreement's NOx, SO2, and PM10 PSELs are 137, 108, and 55 tons, respectively. While the Agreement's PSELs apply to the entire facility, not just Furnace D, Furnace D is by far the most significant source of emissions at the facility, and the new PSELs are higher than the PSELs that DEQ indicated previously applied just to Furnace D. Therefore, the PSELs are likely have no impact on the total emissions of the facility. In contrast, the four-factor analysis would have required the installation of ceramic catalytic filters that would have reduced the NOx and SO2 emissions by 90% and the PM10 emissions by 99%. DEQ should have required the installation of a ceramic catalytic filter for Furnace D.

C. DEQ Cannot Use Backroom Agreements to Exempt Sources from the Requirement to Install Reasonable Progress Controls.

Nothing in the Clean Air Act, Regional Haze Rules, or EPA guidance allows Oregon to exempt sources it has identified for reasonable progress controls from installing effective emissions controls that have satisfied the state's thresholds and programmatic requirements. DEQ's backroom agreements allowing sources to avoid installing such controls cuts directly against EPA's explicit guidance that states generally should not reject reasonable controls, regardless of the other emissions-reducing measures that have been taken:

> [A] state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas. More broadly, we do not think a state should rely on these two additional factors to summarily assert that the state has already made

sufficient progress and, therefore, no sources need to be selected or no new controls are needed regardless of the outcome of four-factor analyses.

EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021), § 5.2, https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation.

By offering sources with cost-effective controls the option to do "alternative compliance" that results in fewer emissions reductions rather than install the reasonable progress control DEQ identified through a four-factor analysis, Oregon has failed to follow this EPA guidance.

D. Oregon Cannot Get on the Glidepath or Achieve Reasonable Progress Goals While Off-Ramping Sources with Cost-Effective Controls Available.

The 2017 Regional Haze Rule requires states to determine the rate of improvement in visibility that would need to be maintained during each implementation period in order to reach natural conditions by 2064 for the 20% most impaired days. The "glidepath," or Uniform Rate of Progress (URP), is the amount of visibility improvement that would be needed to stay on a linear path from the baseline period to natural conditions.

In 2018, eight Class I areas were "just barely" meeting the Uniform Rate of Progress, meaning they were within 5% above the glidepath, while four Class I areas were below the glidepath. *See* SIP at 4. Oregon's projections for 2028 show eight Class I areas more than 5% above the glidepath, no longer meeting the Uniform Rate of Progress, with two more areas within 5% above the glidepath. *See id.* Only Mount Hood Wilderness is projected to be below the glidepath. *See* SIP at 5.

Importantly, however, DEQ's projections for 2028 are based on the assumption that DEQ would order stationary sources to install "controls recommended from DEQ's review of initial four factor analyses submittals[.]" SIP at 75. The projections do not account for the "alternative compliance" option that 15 of these stationary sources received and accepted. In other words, even if Oregon had ordered all 17 facilities that identified cost-effective controls to install reasonable progress controls, Oregon would not be able to achieve its reasonable progress goals for most Class I areas.

Oregon's decision to offer "alternative compliance" to 15 of these facilities further undermines Oregon's ability to stay on the glidepath. The reductions projected for Class I visibility restoration will not occur because DEQ has declined to enter the orders on which those projected reductions are based and instead entered agreements that will result in either fewer reductions or no reductions at all. By relying on this modeling in the SIP after DEQ declined to order these facilities to install reasonable progress controls, the state has misled the public about its ability to achieve the state's reasonable progress goals and stay below the glidepath.

Even if DEQ's decision to make back-room agreements with 15 facilities did not undermine Oregon's ability to get on the glidepath towards natural conditions by 2064 (which it does), the Uniform Rate of Progress is not a "safe harbor" and "states may not subsequently reject control measures that they have already determined are reasonable." 82 Fed. Reg. 3078, 3093. In other words: DEQ's decision to reject reasonable progress controls and instead enter agreements not based on a four-factor analysis violates the Regional Haze Rules ***regardless*** of whether Oregon can still stay on the glidepath.

E. Oregon's Long-Term Strategy Runs Afoul of the Regional Haze Requirements

EPA's recent guidance clarifies the relationship between four-factor analysis, long-term strategy, and reasonable progress goals:

> Reasonable progress towards natural visibility conditions at any particular Class I area is achieved when all contributing states are implementing the measures in their long-term strategies. RPGs are the modeled result of the measures in states' long-term strategies, as well as other measures required under the CAA (that have compliance dates on or before the end of 2028). RPGs cannot be determined before states have conducted their four-factor analyses and determined the control measures that are necessary to make reasonable progress.

EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021), § 3.1, https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation.

Because of DEQ's decision to broadly offer "alternative compliance," DEQ's long-term strategy is fatally flawed and violates the Clean Air Act and Regional Haze requirements. The agency initially used the four factors to identify reasonable progress controls for 17 sources of haze-forming pollution, and sent those sources "control letters" indicating what controls they would likely be required to install based on a four-factor analysis. The SIP includes modeling based on the reductions that would result from the installation of these controls.

But DEQ inexplicably abandoned all reference to the four factors or to reasonable progress when it entered backroom agreements exempting 15 of those sources from the requirement to install the reasonable progress controls that had been identified through the four-factor analyses, and never modeled the impact of these agreements. DEQ's indiscriminate use of "alternative compliance" leaves Oregon unable to satisfy the long-term strategy requirement. Oregon cannot determine the emissions reduction measures necessary to make reasonable progress without conducting the statutorily required four-factor analysis of its emissions reduction strategies. Oregon also cannot demonstrate how the four factors were taken into consideration in selecting these "alternative compliance" measures for inclusion in its long-term strategy because the state did not take these requirements into account.

II. EVEN ASSUMING IT WOULD BE PERMISSIBLE UNDER SOME CIRCUMSTANCES TO OFFER FACILITIES AN OFF-RAMP FROM THE PROGRAM, THE SIP FAILS TO ADEQUATELY JUSTIFY THIS DECISION.

Even assuming the Clean Air Act and Regional Haze Rules permit Oregon to offer "alternative compliance" to facilities that have already undergone a four-factor analysis and identified cost-effective controls, which they do not, Oregon's SIP does not contain adequate analysis and documentation to justify DEQ's decision to offer alternative compliance to each of the off-ramped facilities under the present circumstances.

DEQ claims that it "offered facilities an option when their actual emissions had a screening value (Q/d) of less than the threshold of 5.00, but the screening value was greater than 5.00. Those facilities could lower PSELs and screen out of the FFA process." SIP at 48. However, only half of the facilities to which DEQ offered alternative compliance had actual Q/d below the 5.00 threshold. Owens-Brockway, Gilchrist Forest Products, Boise Cascade Wood Elgin Complex, Georgia Pacific Wauna Mill, Cascade Pacific Halsey Pulp Mill, International Paper Springfield, Georgia-Pacific Toledo, and Roseburg Forest Products Dillard all had actual 2017 emissions equivalent to a Q/d above 5.00, but they nonetheless received offers to enter stipulated agreements and final orders and thereby avoid being ordered to install the cost-effective controls identified in their four-factor analyses.[11]

The SIP contains no evidence that DEQ's decisions to offer alternative compliance to each of the off-ramped facilities were based on four-factor analyses. Nor is there any evidence that the decisions were based on any of the other decision-making frameworks DEQ outlined in the SIP, such as the weight-of-the-evidence framework or framework for evaluating environmental justice. Indeed, there is no evidence that DEQ analyzed the impact of allowing these facilities to screen out of the program or compared the alternative compliance options to reasonable progress controls before entering into these agreements. The SIP consistently describes this decision as being the facilities' choice, rather than DEQ's.[12]

Without analysis to support DEQ's decision to off-ramp facilities where reasonable progress controls were available or analysis of how off-ramping facilities instead of ordering them to install cost-effective controls identified in their four-factor analyses will affect Oregon's progress towards natural visibility, the SIP violates the Regional Haze rules, which require every SIP to contain a description of "how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy." 40 C.F.R. § 51.308(f)(2)(i). DEQ's description of its long-term strategy is cursory, conclusory, and lacking in analysis.[13]

Notably, nothing in SIP reflects any determinations by DEQ that the reduced PSELs or other pollution-controlling operations steps in the Stipulated Agreements and Final Orders would "provide for equivalent reductions to those identified in its review and adjustment of the four-factor analysis." OAR 340-223-0110(2)(b)(C)–(E). Indeed, documenting such a determination would be impossible because the requirements of the stipulated agreements demonstrably do not provide for equivalent emissions reductions to installing the cost-effective controls identified in the four-factor analyses. *See supra* § I(B).

It is notable that DEQ didn't even include the four-factor analyses or control letters for the off-ramped facilities in the SIP. Although the Notice of Rulemaking contains a link to DEQ's website where these documents can be found, their omission in the SIP reflects how divorced these facilities' stipulated agreements are from the assessments reflected in the four-factor analyses and control letters.

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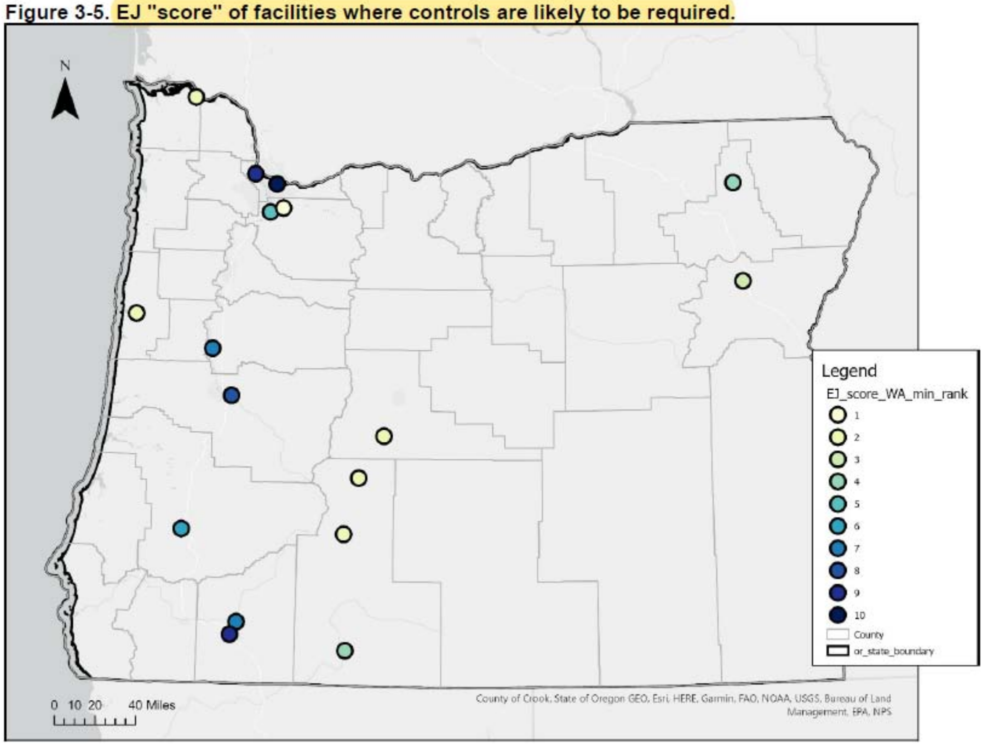
[11] *See* Table 3-6, SIP at 45 (showing actual Q/d > 5 for Owens-Brockway Glass Container, Gilchrist Forest Products, Boise Cascade Wood – Elgin Complex, Georgia Pacific – Wauna Mill, Cascade Pacific Pulp – Halsey Pulp Mill, International Paper – Springfield, Georgia-Pacific – Toledo, Roseburg Forest Products – Dillard); Appendix E (Stipulated Agreements and Final Orders for all eight facilities).
[12] *See, e.g.,* SIP at 48 (referring to "facilities choosing to comply with Regional Haze Round 2 through PSEL reduction"); *id.* at 51 ("Owens-Brockway chose the alternative compliance option to lower PSELs."); *id.* at 52 ("Boise Cascade [Elgin Complex] chose an alternative compliance option"); *id.* at 53 ("Georgia Pacific [Wauna Mill] chose an alternative compliance option"); *id.* at 54 ("Rather than install controls, Boise Cascade [Medford] chose the alternative compliance option"); *id.* at 59 ("Rather than install controls, Jeld-Wen decided to reduce their PSEL so that Q/d < 5.").
[13] *See* SIP at 66 ("DEQ's long term strategy for stationary sources that DEQ determined in Regional Haze Round 2 are likely to contribute to visibility impairment is to implement the mandatory controls and PSEL reductions described in Section 3.6.").

III. DEQ'S DECISION TO OFF-RAMP FACILITIES INSTEAD OF ORDERING THEM TO INSTALL REASONABLE PROGRESS CONTROLS UNDERMINES OREGON'S COMMITMENT TO ENVIRONMENTAL JUSTICE.

Although Oregon's Regional Haze rules require DEQ to take environmental justice into account when selecting emissions controls for sources, DEQ offered the state's largest polluters an exit plan from the requirement to install emissions controls seemingly without any consideration for Oregon's environmental justice communities—the very communities bearing the brunt of pollution. DEQ defines environmental justice as requiring "the fair and meaningful involvement" of affected communities. *See* SIP 39. And yet, DEQ decided to off-ramp major polluters in overburdened communities without any consultation with those communities. DEQ's actions in extending "alternative compliance" are wholly at odds with its claim that "DEQ believes that emission reductions in Oregon should be targeted towards those communities that experience the greatest burden." SIP at 38.

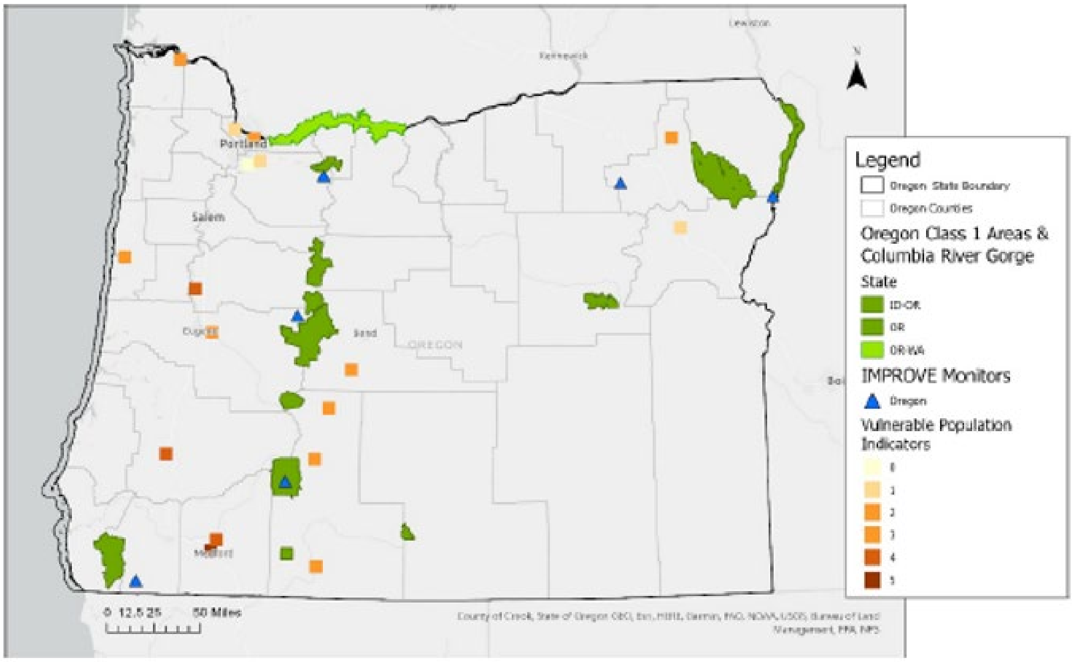
Despite the claim in the SIP that DEQ incorporated environmental justice into its regional haze decisions, nothing in the SIP suggests that DEQ considered environmental justice in making the choice to extend "alternative compliance" to 16 of the 17 facilities with reasonable progress controls. While DEQ carefully established a protocol and analyzed the environmental justice and vulnerable populations "score" of each facility with cost-effective controls identified in its four-factor analysis, it then seemingly ignored this information when making consequential decisions: in place of actual significant reductions in emissions that would be achieved though the implementation of four factor reasonable progress control analyses the agency instead established alternative compliance to these facilities regardless of the environmental justice impacts and the impacts on vulnerable populations.

Figure 3-5. EJ "score" of facilities where controls are likely to be required.

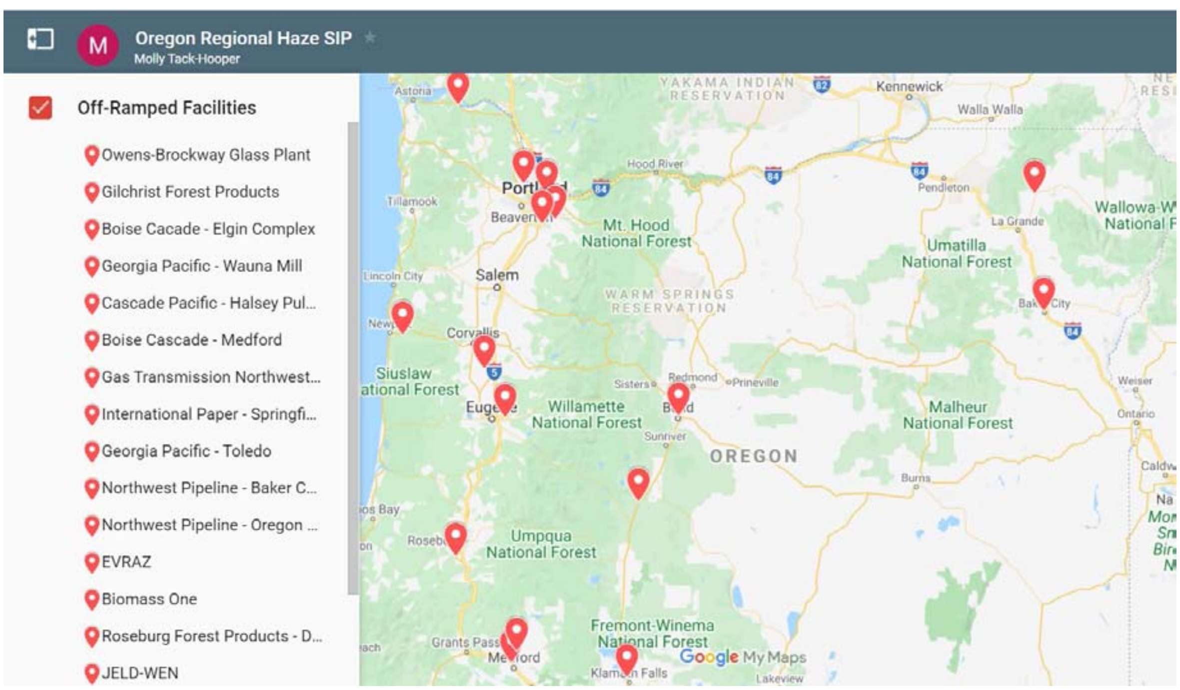


See Table 3-5, SIP at 44.

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



See Figure 3-3, SIP at 40-41.



See Off-Ramped Facilities, Regional Haze Map, https://tinyurl.com/2zmcswuc.

DEQ's backroom agreement with Owens-Brockway underscores the environmental justice costs of allowing some of the state's largest polluters to off-ramp from the Regional Haze Program without requiring actual emission reductions equivalent to what could have been achieved from requiring the facility to install reasonable progress controls.

Owens-Brockway is glass recycling facility that sits between three public schools in Portland's Cully neighborhood, which is home to one of Portland's most diverse census tracts, with more than 50 percent of residents representing communities of color. More than a quarter of Cully residents are low income.[14] According to the most recent National Air Toxics Assessment based on 2014 data, the neighborhoods in closest proximity to the Owens-Brockway plant experience an elevated cancer risk of 40 in one million from air toxics (without accounting for diesel particulate matter and other air toxics for which EPA does not have health-effects data). Given the concentration of environmental health risks in the area and the high percentages of Cully residents that are of color or low-income, this neighborhood, which surrounds the Owens-Brockway facility, is considered an overburdened community.[15]

Although Owens-Brockway voluntarily shut down one of its two furnaces in June 2020 and DEQ ordered the facility to that furnace shut down in June 2021 in connection with an enforcement action, the remaining furnace still exposes neighboring communities to SO2 and NOx—pollutants that can adversely affect lung function and worsen asthma attacks. Modeling recently uncovered that, even when only the sole remaining furnace is running, the Owens-Brockway facility may be causing or contributing to violations of the 1-hour SO2 and 1-hour NOx National Ambient Air Quality Standards designed to protect public health and the environment.[16]

In an enforcement letter to Owens-Brockway, DEQ staff urged Owens-Brockway to voluntarily install a catalytic ceramic filter to address multiple pollutants of concern, noting that it was deemed cost-effective under the Regional Haze program.[17] And in conversations with advocates about their concerns around Owens-Brockway, DEQ staff pointed to Regional Haze program as potential legal lever to order the facility to install a catalytic ceramic filter to address multiple pollutants of concern if the facility would not do so voluntarily. Advocates amplified DEQ's request, asking the facility to voluntarily install pollution controls to address the multiple pollutants of concern.[18]

However, behind closed doors, DEQ did an about-face, and inexplicably offered this facility—which DEQ has described as having a "history of chronic noncompliance" with regulatory requirements[19]—the "alternative compliance" option to reduce the unnecessary overhead in its permit instead of ordering it to install the pollution controls advocates have been asking for, which the facility had declined to install voluntarily.

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[14] To view data, visit https://ejscreen.epa.gov/mapper/; navigate to "Select Location;" "Enter a location or a latitude/longitude;" then enter "97220" and "Get Printable Standard Report." 97220 is the zip code for the Owens-Brockway facility. The process can be repeated for 97218, the Cully zip code.
[15] EPA glossary, https://www.epa.gov/environmentaljustice/ej-2020-glossary.http://npirspublic.ceris.purdue.edu/ppis/product.aspx.
[16] Earthjustice, *Owens-Brockway: An Environmental Justice Problem in Portland* (Sep. 2021), https://earthjustice.org/sites/default/files/files/2021.09.23_portland_air_pollution.pdf.
[17] Oregon DEQ, Letter to Owens-Brockway (June 3, 2021) at 2, https://www.oregon.gov/deq/nr/OwensBrockway2020208NCPO.pdf.
[18] Community Input Regarding Owens-Brockway's CAA Title V Violation (June 28, 2021), https://earthjustice.org/sites/default/files/files/community_ltr_to_owens_re_1mil_fine_-_revised_formatting_002.pdf.
[19] Oregon DEQ, Letter to Owens-Brockway (June 3, 2021), https://www.oregon.gov/deq/nr/OwensBrockway2020208NCPO.pdf.

The new permit emission limits in the "alternative compliance" agreement do not require Owens-Brockway to in any way change its operations, effectively resulting in no actual emission reductions on the ground. And even if the new permit emission limits had required actual reductions in NOx, SO2, and PM10, these limits would not reduce these pollutants in an amount equivalent to the reductions that would result from the installation of a ceramic catalytic filter as should be required for reasonable progress, which would have reduced the facility's NOx and SO2 emissions by 90% and the PM10 emissions by 99%, delivering far greater public health benefits.

Nothing in the SIP explains how offering Owens-Brockway "alternative compliance" instead of ordering it to install reasonable progress controls benefits the environmental justice community where the facility sits—nor could it.[20]

IV. INADEQUATE DOCUMENTATION OF COST ANALYSES

The National Park Service repeatedly notified DEQ of errors in the cost analyses for 10 facilities,[21] including incorrect equipment life, interest rate, retrofit factors, and assorted errors to inputs to SCR and other cost algorithms. *See* SIP at App'x G. Making these corrections often drastically improves the cost-effectiveness of controls at many facilities. It appears that DEQ responded to this feedback by making some recommended corrections to facility cost analyses, including corrections to the interest rate and equipment life, but DEQ did not include any documents reflecting this revised analysis either in the SIP or on DEQ's website. *See id.* With respect to other facilities, it is unclear whether DEQ adequately revised its analysis to correct errors and omissions. Some facilities failed to provide adequate documentation to support their cost analyses, including full vendor information, but nothing in the SIP indicates whether DEQ ever obtained this information to confirm the facilities' cost analyses. For instance, as the National Park Service noted, the cost analyses performed by All4 for the Northwest Pulp & Paper Association erroneously assumed a retrofit factor of 1.5 for every wood waste boiler it evaluated in Oregon, the effect of which is to artificially increase the capital cost by 50%. *E.g.*, SIP at 93. There is no record that DEQ made these corrections.

Omitting complete cost analysis documentation from the SIP violates the requirement in the 2017 Regional Haze rules to "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I area it affects" including the "cost and engineering information on which they are relying to evaluate the costs of compliance, the time necessary for compliance, the energy and non-air quality impacts of compliance and the remaining useful lives of sources." 82 Fed. Reg. 3078-01, 3096 (Jan. 10, 2017). EPA has been explicit that "every source-

[20] We understand that DEQ and Owens-Brockway reached an agreement to settle Owens-Brockway's enforcement action, and that the agreement requires Owens-Brockway to install unspecified controls to reduce PM by 95% by June 30, 2022. *See* DEQ, DEQ reaches agreement with Owens-Brockway: install pollution controls or shut down (Oct. 22, 2021), https://www.oregon.gov/newsroom/Pages/NewsDetail.aspx?newsid=64500. The fact that DEQ eventually used legal authority outside of the Regional Haze program to require the facility to install controls to address some of the facility's pollutants of concern does not change the fact that DEQ should have used its Regional Haze power to that end, and violated the Regional Haze rules by failing to do so. Ordering Owens-Brockway to install a ceramic catalytic filter would not have precluded DEQ from imposing any of the terms in the subsequent enforcement order.

[21] Boise Cascade – Elgin, Boise Cascade – Medford, Georgia Pacific – Toledo, Georgia Pacific – Wauna Mill, Cascade Pacific Pulp – Halsey Pulp Mill, International Paper – Springfield, Gas Transmission Northwest – Compressor Station 12, Gas Transmission Northwest – Compressor Station 13, Biomass One, and Roseburg Forest Products – Dillard.

specific cost estimate used to support an analysis of control measures must be documented in the SIP." EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, (Aug. 20, 2019), § 4(c) at 32, https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Conclusion

For all of the foregoing reasons, we urge DEQ and EQC to revise Oregon's State Implementation Plan. The proposed Plan violates federal law, and will not achieve the emissions reductions necessary to protect visibility in Oregon's Class I areas. The proposed SIP misses the opportunity to protect the health of environmental justice communities in Oregon and evades the Regional Haze requirements that obligate the state to undertake actions in keeping with this objective.

To comply with the Regional Haze rules, DEQ must vacate its "alternative compliance" agreements, which are plainly contrary to the requirements of the Clean Air Act and Regional Haze rules and instead require these facilities to install and operate the most effective reasonable progress controls. Oregon's SIP must demonstrate that DEQ selected and ordered reasonable progress controls for 17 facilities based on a proper four-factor analysis, taking into account environmental justice, and that any orders or agreements deliver emissions reductions at least equivalent to those that would be obtained through the installation of the reasonable progress controls identified in DEQ's control letters.

Sincerely,

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November 1, 2021

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RE: Regional Haze: 2018-2028 State Implementation Plan Comments by Environmental and Community Advocates- Woodburning

Dear Ms. Williams—

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

A. Residential Biomass

While we are excited that this is recognized as a source of emissions, the current draft SIP is insufficient in its proposed rules to reduce emissions from biomass burning/residential woodsmoke. Residential wood smoke may have a particularly pronounced effect in the Columbia River Gorge National Scenic Area due to geography, residential land use in the george, and proximity to population centers where residential wood combustion is common. Section **4.6.2 "Residential Wood Heating" of the SIP merely** states:

> "Oregon's HeatSmart program reduces emissions from residential wood combustion by requiring uncertified stoves to be removed at the time of home sales for the whole state. In addition, community grants authorized by the Oregon Legislature and administered by DEQ pay for wood stove changeouts to natural gas or electric-powered home heating devices in communities for which fine particulate matter pollution has been identified as a major source of wintertime air pollution. DEQ expects to continue to receive

Legislative funding for woodsmoke reduction work in the coming years, although cannot count on a specific level of support."[1]

The purpose of the Regional Haze Program is to improve visibility in Class I wilderness areas with the goal to attain natural visibility conditions by 2064.[2] While the Haze program is intended to address visibility, visibility problems are caused by the same air pollution that causes deadly health impacts- such as particulate matter, nitrogen oxides and sulfur oxides. SIPs must include federally enforceable rules for sources to reduce emissions of haze-forming pollutants, and must address each source or source category separately. Specifically, Section 51.308(f)(2)(i) of the Regional Haze Rule (40 CFR § 51.308) requires a SIP to include a description of the criteria the state has used to determine the sources or groups of sources it evaluates for potential controls.[3] A state opting to select a set of sources must make "reasonable progress towards natural visibility" which can also be based on the long-term strategy for regional haze.[4] Amongst the 5 factors for long-term strategy are emissions reductions due to: ongoing air pollution control programs, basic smoke management practices for prescribed fire, and the anticipated 'net effect' on visibility due to projected changes in point, area, and mobile source emissions.[5]

In this case, residential wood burning is both a point/area source and has various local and state level programs to mitigate its emissions. We are disappointed that Section 4.6.2 of the SIP, which covers residential wood burning sources, is so sparse and does not adequately address biomass emissions. To begin, we would like DEQ to recognize the insufficiency of the HeatSmart Program as a main approach to reduce emissions. Numerous peer reviewed scientific studies show that woodstove changeouts that upgrade old stoves to "cleaner" woodstoves (like HeatSmart) do not meaningfully decrease pollution: "An in-depth evaluation of the British Columbia wood stove exchange program published in 2014 noted that 6 years after the program began…there has not yet been a clear reduction in fine particulate matter pollution coming from residential wood stoves in BC."[6] Other studies have concluded that "despite the potential for extensive wood stove exchange programs to reduce outdoor PM2.5 concentrations in wood smoke-impacted communities, we did not find a consistent relationship between stove technology upgrades and indoor air quality improvements in homes where stoves were exchanged."[7]

[1] Oregon Regional Haze State Implementation Plan (Aug. 27, 2021): Public Notice Draft at p. 70.
[2] https://www.oregon.gov/deq/Regulations/rulemaking/Pages/rhsip2028.aspx.
[3] EPA Regional Haze Guidance (Aug. 20 2019) at p. 9.
[4] 40 CFR 51.308(f)(2)(iv).
A state that brings no sources forward for analysis of control measures
[5] 40 CFR 51.308(f)(2)(iv).
[6] BC Wood Stove Exchange Program Evaluation (2008 to 2014), available at https://www2.gov.bc.ca/assets/gov/environment/air-land-water/air/reports-pub/wsep_evaluation.pdf.
[7] The impact of wood stove technology upgrades on indoor residential air quality (2009), available at https://www.sciencedirect.com/science/article/abs/pii/S1352231009007389.

Smoke created from wood burning can be a significant source of air pollution and haze. In fact, at least one Biomass facility in Oregon (Biomass One, LP), has been determined to impact Class I areas and was required to undergo a four-factor analysis.[8] Burning wood releases the same pollutants as wildfires- including but not limited to Sulfur Dioxide, Nitrogen Dioxide, Particulate Matter (direct and precursor pollutants that can impair visibility)[9] and Carbon Monoxide, which are all criteria pollutants under the Clean Air Act's National Ambient Air Quality Standards (40 CFR part 50). Residential wood burning contributes to approximately 12.8 million pounds of PM 2.5 throughout our state, based on the 2017 EPA emissions inventory.[10] And according to DEQ's 2014 Woodsmoke combustion survey, up to 37% of Oregonians burn wood in their homes.[11] It is estimated that 591,000 homes have a wood burning device. Approximately 150,000 homes have an uncertified wood stove and 212,000 homes have a fireplace.[12] Taken cumulatively, that is a lot of biomass emissions and wood burning near various Class I areas. And that does not even count the outdoor residential and recreational burning that occurs. The current SIP fails to consider the 'net effect' of all indoor and outdoor residential burning on air quality and visibility within a region, nor all ways to mitigate it.

The draft SIP fails to mention the specific DEQ statewide woodstove changeout program which allots specific counties grant amounts to help their residents change out their woodstoves and the existing locally-backed education and woodsmoke curtailment programs in each County. It also fails to mention federal ARPA funding- which has been allotted in the amount of $500,000 for woodsmoke changeouts in Multnomah County for the next biennium. The SIP could be strengthened if it incorporated the recognition of additional grant funding needed to continue woodstove changeouts towards non-biomass devices, other policies mentioned in DEQ's 2016 report to the legislature, and the policy proposals from the Multnomah County 2021 woodsmoke working group- which DEQ participated in. This includes but is not limited to:

- Additional grant funding dedicated to providing woodstove changeouts for heat pumps or other non-biomass burning devices .
- More DEQ funding for locally run woodsmoke curtailment programs and public education programs tailored for their residents. Many of them already exist, and require

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[8] Oregon Regional Haze State Implementation Plan (Aug. 27 2021).

[9] EPA Regional Haze Guidance (Aug. 20 2019) at p. 11, available at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

[10] https://www.opb.org/news/article/oregon-deq-data-woodstove-air-pollution-wildfires/.

[11] DEQ, 2014 Portland residential wood combustion survey (Jan. 2015) at p. 15., available at https://www.oregon.gov/deq/FilterDocs/WoodburningSurvey.pdf.

[12] *Id.* at p. 20.

daily air quality forecasting, technical assistance, compliance monitoring, and enforcement.[13]

- By increasing state funding, each community could employ a full time or dedicated staff-person to implement such programs.[14] Multnomah County just approved an additional $100,000 to employ an air quality specialist in their Health Department for the next biennium to implement their woodsmoke ordinance.
- Increased statewide education and outreach is needed because increasing awareness of the harms of woodsmoke is essential for emissions reduction.[15] Developing and adequately resourcing a multi-year campaign is needed.
- DEQ should be committing to enhanced coordination with other agencies to focus on air quality from wood burning.
- Incentivizing woodstove change outs for heat pumps or other non-biomass burning devices.
- Tax credits should be a part of DEQ's strategy- perhaps through clean energy initiatives.
- DEQ should complete a statewide woodsmoke combustion inventory which will help establish current baseline source emissions. The last one was conducted in 2014 and was limited to the Portland metro area.
- DEQ should consider a permitting scheme for future commercial businesses who want to use a chiminea, chimney, or woodstove based on air quality concerns.

B. Smoke Management and Prescribed Burning

In order to meaningfully address regional haze, DEQ and Department of Forestry would need to consider the rules that allow burning of biomass debris, forest waste on private and public lands and consider volume restrictions. Agencies should limit all unnecessary pile burning and agricultural burning in Oregon. This means that the education and no-burn alternatives should be encouraged and clarified- not in the next few years as stated in the SIP- but almost immediately.[16] All permitted burning should provide scientifically supported data that shows its efficacy in preventing wildfire or providing ecological benefit (prescribed burning). Burning in lieu of forest, domestic or agricultural clean-up practices such as composting should be minimized and limited.

We realize that woodburning and biomass is only one piece of the puzzle contributing to haze. But we urge you to flesh out your long-term strategy and enforceable rules to mitigate emissions.

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[13] DEQ, Woodsmoke in Oregon: HB 3068 Final Report to the Legislature (Sept. 2016) at p. 11.
[14] *Id.*
[15] *Id.*
[16] SIP at p. 69.

Sincerely,

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