# National Parks Conservation Association Et Al

Comment letter, plus attachments 1 through 8

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November 23, 2021

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Air Quality Program
P.O. Box 47600
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*Submitted via email to*: linda.kildahl@ecy.wa.gov and to Ecology's Public Comment Form at https://aq.ecology.commentinput.com/?id=taEN9

Re: Conservation Organizations' Comments Submitted on Washington's Proposed Regional Haze State Implementation Plan for 2018 to 2028

Dear Ms. Kildahl:

The National Parks Conservation Association, Sierra Club, Alpine Lakes Protection Society, North Cascades Conservation Council, Olympic Park Advocates, Puget Soundkeeper Alliance (PSK), Stand.earth, and Waste Action Project ("Conservation Organizations") submit the following and attached comments regarding the Washington Department of Ecology's ("Ecology, DOE") Proposed Regional Haze State Implementation Plan ("SIP") for 2018 to 2028.[1]

**National Parks Conservation Association** ("NPCA") is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education. NPCA has over 1.64 million members and supporters nationwide, with more than 42,000 in WA state, with its main office in Washington, D.C. and 24 regional and field offices. NPCA is active nation-wide in advocating for strong air quality requirements to protect our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, climate change and mercury impacts on parks, and emissions from individual power plants and other sources of pollution affecting National Parks and communities. NPCA's members live near, work at, and recreate in all the national parks, including those directly affected by emissions from Washington's sources.

**Sierra Club** is a national nonprofit organization with 67 chapters and about 830,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club has long participated in Regional Haze rulemaking and litigation across the country in order to advocate for public health and our nation's national parks. The Washington Chapter of the Sierra Club has approximately 32,000 members.

**The Alpine Lakes Protection Society (ALPS)** promotes environmental protection and conservation of the Alpine Lakes Wilderness (ALW) and surrounding area of the Central Cascades. Since the creation of this federal Wilderness in 1968, ALPS has fought to protect it against exploitation. ALPS is an all-volunteer organization sustained by its members. ALPS members have many decades of experience working to keep the ALW wild and is not beholden to big corporate donors or foundations, meaning that ALPS can, and do, take the tough stands against harmful projects that threaten our protected wilderness.

**The North Cascades Conservation Council (N3C)** was founded in 1957, and our mission is to protect and preserve the scenic, scientific, recreational, educational, and wilderness values in

[1] Victoria R. Stamper, "Review and Comments on Washington Department of Ecology's Draft Regional Haze Plan for the Second Implementation Period: Long Term Strategy and Four-Factor Analysis of Controls" (Nov. 19, 2021) ("Stamper Report") (Enclosure 1). Ms. Stamper is an independent air quality consultant and engineer with extensive experience in the regional haze program. Steven Klafka, P.E. BCEE, Environmental Engineer, Wingra Engineering, S.C, "The Four-Factor Reasonable Progress Analysis for Ardagh Glass" (Jan. 27, 2021) ("Klafka Report") (Enclosure 2). Also enclosed are NPCA's comments submitted on the Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), which included proposed source-specific amendments for Ecology's Regional Haze SIP Revision, (Dec. 3, 2020) (Enclosure 3), and comments submitted by the Conservation Organizations on February 16, 2021 (submitted with corrections on February 19, 2021) (Enclosure 4).

Washington State. N3C is an independent, all-volunteer organization whose work is carried out by our board and 200 members.

**Waste Action Project (WAP)** has been around since 1994. WAP focuses on advocacy and education, and the Clean Water Act and has also provided technical and other support for communities for issues around the Clean Water Act, Superfund, Resource Conservation Recovery Act, and Model Toxics Control Act. WAP are a co-founder of Duwamish River Cleanup Coalition, and for the first few years oversaw DRCC's EPA Technical Assistance Grant for the Lower Duwamish Waterway Superfund Site. WAP has worked with impacted communities around the state to better understand their rights to clean water, and implementation of restoration and water quality improvement projects.

**Olympic Park Advocates (OPA)** is a 501(c)(3) nonprofit citizens conservation organization working to protect the beauty, integrity and biological diversity of Olympic National Park and the Olympic ecosystem. OPA was founded in 1948 to defend the Park against attacks on its spectacular old-growth rain forest valleys. Seventy-three years later, OPA's more than 240 Washington members recognize that having pristine air in Olympic National Park is necessary for the protection of this special place.

**Puget Soundkeeper Alliance (PSK)** is a regional organization whose mission is to protect and enhance the waters of Puget Sound for the health and restoration of our aquatic ecosystems and the communities that depend on them. PSK conducts outreach via stewardship, advocacy, monitoring and enforcement in order to achieve behavior change and systems change. PSK currently has 1,898 members who live, work, play, and worship all round Puget Sound and its tributaries, and have strong interests in protecting the waters from pollution and associated harms to community health. PSK is currently prosecuting Clean Water Act lawsuits against both Ardagh Glass and Ash Grove Cement for violations of National Pollution Discharge Elimination System (NPDES) permits. Though PSK is a water quality focused organization, it acknowledges and appreciates the undeniable intersectionality of water and air pollution with human health, and with racial and environmental justice.

**Stand** was created to challenge corporations and governments to treat people and the environment with respect, because our lives depend on it. Born as Forest Ethics, Stand's work and its approach has evolved from a dedicated focus on forest protection to taking on some of the root causes of climate change and environmental injustice. Stand pursues audacious solutions, campaigns for as long as it takes to see them through, punches way above our weight, and treats everyone with respect. From keeping communities safe from dozens of proposed oil-by-rail terminals to protecting more than 65 million acres of forest from logging, Stand's work has resulted in sweeping industry-wide changes and environmental protection on a massive scale.

As discussed in these comments, we have serious concerns regarding Ecology's proposed Regional Haze SIP for the Second Implementation Period. Ecology must correct the following flaws:

- EPA cannot approve Ecology's proposed reliance on Reasonably Available Control Technology ("State-RACT") to meet the RP regional haze requirements. Washington's

RACT requirements are less than stringent and not equivalent to the CAA's regional haze Four-Factor Analysis reasonable progress requirements. Indeed, Ecology describes its State-RACT as a "C-grade" control or emission limit;[2]

- Although Ecology's proposed SIP identifies the five refineries as *the priority source sector* for controls, it fails to include emission controls, instead proposes delay until the next ten-year implementation period.[3]
- Ecology's only proposed reductions come from alleged "on-the-books" emission reductions from the following sources:

    - TransAlta Centralia Generation (BART order revision, which ceased coal-fired operation of one boiler in December 2020 and will cease coal-fired operation of the other boiler by the end of 2025);
    - Cardinal FG Winlock Glass Plant (which voluntarily requested a permit to install selective catalytic reduction (SCR) on its glass furnace in conjunction with an increase in glass production capacity. A permit was issued authorizing these actions on February 11, 2001, and Ecology states that the SCR should be installed and operating by 2022);
    - Ash Grove Cement Company (which entered into a Consent Decree in 2013 with EPA, Ecology, and other state agencies that required optimization of the Seattle Kiln to reduce NOx emissions and is currently subject to a NOx limit of 5.1 lb/ton of clinker); and
    - Alcoa Wenatchee and Intalco Aluminum (which are both currently in "curtailment due to market conditions," for which ECOLOGY has proposed Agreed Orders to require the plants to conduct and submit a four-factor analysis of controls if they decide to restart operations).

- Despite applying EPA methodology and identifying cost-effective controls three pulp and paper mills and the sulfite mill, Ecology proposes no controls at these facilities.[4]
- Ecology improperly defers making any four-factor determinations based on purported emission reductions from existing Clean Air Act programs (*i.e.,* permits and state rules).[5]
- As explained in the attached Report prepared by Steven Klafka, Ecology must evaluate cost-effective and achievable emission reductions for *all* Washington's largest sources, including Ardagh Glass.
- The draft SIP fails to include Four-Factor Analyses for the Alcoa Wenatchee and Intalco facilities, and there are numerous approvability issues with the Agreed Orders for Alcoa Wenatchee and Intalco.

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[2] Draft SIP, Appendix A at A-10, Ecology's response to the Nov. 19, 2020 email from the National Park Service.
[3] Draft SIP at 187. ("All controls identified as reasonable in the reasonability analysis will be installed and operated as an enforceable requirement consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.")
[4] Nippon Dynawave Packaging Company Longview, Georgia-Pacific Consumer Operations, LLC, WestRock Longview, LLC, WestRock PC, LLC Tacoma, Port Townsend Paper Corporation, Packaging Corporation of America Wallula, and Cosmo Specialty Fibers Mill.
[5] Draft SIP at 23 ("The long-term strategy in this regional haze SIP revision includes emission reductions from permits and state rules.")

- The draft SIP fails to *first* evaluate whether additional emission reductions from sources are necessary via the Four-Factor Analysis reasonable progress determinations to ensure reasonable progress toward the Clean Air Act's visibility goal.[6]
- Ecology's consultation with the Federal Land Managers is flawed and incomplete.
- The draft SIP fails to *evaluate* environmental justice impacts, resulting in a proposed SIP that does not consider equity or reduce emissions and minimize harms to disproportionately impacted communities.[7]

The Clean Air Act requirements for Washington's regional haze plan present a significant opportunity to not only improve the skies at Mount Rainier, North Cascades and Olympic National Parks as well as across the region's treasured public lands but also the air quality in communities across the state, including some of the most disproportionately affected by health harming pollution that can and must be abated. Despite the legal requirements necessary to ensure reasonable progress, Ecology's draft SIP contains fundamental flaws and fails to propose any new emission reductions for its sources.

Our comments present these issues and offer detailed suggestions to ensure that the SIP Ecology submits to EPA will be in line with the legal requirements of the Clean Air Act and federal regulations, and address visibility impairing emissions.

[6] Draft SIP at 219. ("Ecology's calculation of RPGs relies on technical data and analysis developed by the Western Regional Air Partnership (WRAP)," which was developed before identification of sources and the Four-Factor Analyses.)
[7] Draft SIP at 22-24.

**Conservation Organizations' Comments**
**Washington's Proposed Regional Haze State Implementation Plan for 2018 to 2028**
**November 23, 2021**

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## I. Introduction and Background

Washington is home to three national parks, Mount Rainier, Olympic, and North Cascades National Parks, and five wilderness areas, Alpine Lakes, Glacier Peak, Goat Rocks, Mount Adams, and Pasayten Wilderness Areas. Our national parks and wilderness areas are iconic, treasured landscapes and Washington is rich in national parks and natural areas.

Congress set aside these national parks and wilderness areas to protect our natural heritage for generations. Washington's protected areas also generate millions of dollars in tourism revenue, provide habitat for a range of species, and provide year-round recreational opportunities for residents. These special places are designated "Class I areas" under the Clean Air Act ("CAA") and as such, their air quality is entitled to the highest level of protection.

To improve air quality in our most treasured landscapes, Congress passed the visibility protection provisions of the Clean Air Act in 1977, establishing "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution."[8] "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities."[9] In order to protect Class I areas' "intrinsic beauty and historical and archeological treasures," the regional haze program establishes a national regulatory floor and requires states to design and implement programs to curb haze-causing emissions within their jurisdictions. Each state must submit for EPA review a SIP designed to make reasonable progress toward achieving natural visibility conditions.[10]

A regional haze SIP must provide "emissions limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal."[11] Two of the most critical features of a regional haze SIP are the requirements for installation of Best Available Retrofit Technology ("BART") limits on pollutant emissions *and a long-term strategy for making reasonable progress toward the national visibility goal*.[12] Although many states addressed the Clean Air Act's BART requirements in their initial regional haze plans, EPA's 2017 revisions to the Regional Haze Rule (RHR) make clear that BART was not a once-and-done requirement. Indeed, states "will need" to reassess "BART-eligible sources that installed only moderately effective controls (or no controls at all)" for any additional technically-achievable controls in the second planning period.[13] The haze requirements in the Clean Air Act present an unparalleled opportunity to protect and restore regional air quality by curbing visibility-impairing emissions from a variety of polluting sources.

Implementing the regional haze requirements promises benefits beyond improving views. Pollutants that cause visibility impairment also harm public health. For example, oxides of nitrogen ("NOx") are a precursor to ground-level ozone which is associated with respiratory

[8] 42 U.S.C. § 7491(a)(1).
[9] *Id.* § 7491(g)(3).
[10] *Id.* § 7491(b)(2).
[11] 42 U.S.C. § 7491(b)(2).
[12] *Id.* § 7491(b)(2)(B); 40 C.F.R. § 51.308(d)(1)(i)(B).
[13] 82 Fed. Reg. 3078, 3,083 (Jan. 10, 2017); see also *id.* at 3,096 ("states must evaluate and reassess all elements required by 40 CFR 51.308(d)").

disease and asthma attacks. NOx also reacts with ammonia, moisture and other compounds to form particulates that can cause and/or worsen respiratory diseases, aggravate heart disease, and lead to premature death. Similarly, sulfur dioxide ("$SO_2$") increases asthma symptoms, leads to increased hospital visits, and can also form particulates. NOx and $SO_2$ emissions also harm terrestrial and aquatic plants and animals through acid rain as well as through deposition of nitrates (which in turn cause ecosystem changes including eutrophication of mountain lakes). Unfortunately, the promise is of natural visibility is unfulfilled because the air in most Class I areas, including in Washington's most treasured natural areas, remains polluted by industrial sources, including the sources covered in our comments:

- TransAlta Centralia Generation,
- Ash Grove Cement Plant,
- Cardinal FG Winlock Glass Plant,
- Oil refineries (BP Cherry Point, Phillips 66 Ferndale, Shell Puget Sound, Marathon Petroleum Company Anacortes Refinery, U.S. Oil & Refining Company – Tacoma Refinery),
- Pulp and Paper Mills (Nippon Dynawave Packaging Company Longview, Georgia-Pacific Consumer Operations, LLC, WestRock Longview, LLC, WestRock PC, LLC Tacoma, Port Townsend Paper Corporation, Packaging Corporation of America Wallula),
- Cosmo Specialty Fibers Mill, and
- Ardagh Glass Plant.

## II. The Regional Haze Reasonable Progress Legal Requirements

### A. Requirements for Periodic Comprehensive Revisions for Regional Haze SIPs

In developing its long-term strategy, a state must consider its anthropogenic sources of visibility impairment and evaluate different emission reduction strategies including and beyond those prescribed by the BART provisions.[14] A state should consider "major and minor stationary sources, mobile sources and area sources."[15] At a minimum, a state must consider the following factors in developing its long-term strategy:

> (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
> (B) Measures to mitigate the impacts of construction activities;
> (C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
> (D) Source retirement and replacement schedules;
> (E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
> (F) Enforceability of emission limitations and control measures; and
> (G) The anticipated net effect on visibility due to projected changes in point, area, and

[14] 40 C.F.R. § 51.308(f).
[15] *Id.* § 51.308(f)(2)(i).

> mobile emissions over the period addressed by the long-term strategy.[16]

Additionally, a state

> Must include 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.[17]

In developing its plan, the state must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based.[18] All of this information is part of a state's revised SIP and subject to public notice and comment. A state's reasonable progress analysis must consider the four-factors identified in the Clean Air Act and regulations. *See* CAA 169A(g)(1); 40 C.F.R. 51.308(f)(2)(i) ("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.")

EPA's 2017, Regional Haze Rule Amendments made clear that states are to 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.[19] Specifically, EPA explained in its final notice that it proposed, took and responded to comments and amended 40 C.F.R. § 51.308(f) to eliminate the cross-reference to 40 C.F.R. §51.308(d) to "codify …[its] long-standing interpretation of the way in which the existing regulations were intended to operate" to track "the actual [SIP] planning sequence" as follows, thus, states are required to:

> (1) [C]alculate baseline, current and natural visibility conditions, progress to date and the URP;
> (2) [D]evelop a long-term strategy for addressing regional haze by evaluating the four factors to determine what emission limits and other measures are necessary to make reasonable progress;
> (3) [C]onduct regional-scale modeling of projected future emissions under the long-term strategies to establish RPGs and then compare those goals to the URP line; [FN73] and
> (4) [A]dopt a monitoring strategy and other measures to track future progress and ensure compliance.[20]

Moreover, in promulgating the RHR EPA stated that:

> The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures

[16] *Id.* § 51.308(f)(2)(iv).
[17] 40 C.F.R. § 51.308(f)(2)(i).
[18] 40 C.F.R. § 51.308(f)(2)(i).
[19] 82 Fed. Reg. at 3090-91.
[20] *Id.* at 3091.

> already determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. Rather, the rate of progress that will be achieved by the emission reductions resulting from all reasonable control measures is, by definition, a reasonable rate of progress. … [I]f a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line. *The URP is not a safe harbor*, however, and states may not subsequently reject control measures that they have already determined are reasonable.[21]

Thus, the key determinant in whether a state's "robust determination" obligation has been satisfied under Section 51.308(f)(3)(ii)(B) is not whether the Reasonable Progress Goal ("RPG") of a Class I Area is below that Class I Area's URP, but rather whether a state has considered and determined requirements to make reasonable progress based on the four-factors. A state must consider the four-factors *regardless* of the status of any Class I Area's RPG.

The state's SIP revisions must meet certain procedural and consultation requirements.[22] The state must consult with the Federal Land Manager(s) and look to the Federal Land Managers' expertise of the lands and knowledge of the way pollution harms them to guide the state to ensure SIPs do what they must to help restore natural skies.[23] The RHR also requires that in "developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers."[24]

The duty to ensure reasonable progress requirements are met for purposes of the SIP rests with the state. While the WRAP plays an important role in providing support in regional haze planning, the state is ultimately accountable for preparing, adopting, and submitting a compliant SIP to EPA. Further, as discussed more fully below, Ecology has an obligation to cite to the technical support documentation it proposes to rely on and use as part of its SIP revision.[25]

### B. EPA's 2019 Guidance

Additionally, as you may know, in May 2020, NPCA shared the petition it submitted to the previous EPA Administrator - which sought reconsideration of the 2019 RH guidance - alongside a cover letter to Washington.[26] In addition to NPCA, Sierra Club, Natural Resources Defense Council, Western Environmental Law Center, Appalachian Mountain Club, Coalition to Protect America's National Parks, and Earthjustice, signed the petition for reconsideration. As of

[21] *See*, 82 Fed. Reg. 3093 (emphasis added).
[22] For example, in addition to the RHR requirements, states must also follow the SIP processing requirements in 40 C.F.R. §§ 51.104, 51.102.
[23] 40 C.F.R. § 51.308(i).
[24] *Id.* § 51.308(i)(3).
[25] *See, e.g.,* 40 C.F.R. §§ 51.100, 51.102, 51.103, 51.104, 51.105 and Appendix V to Part 51.
[26] "Petition for Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," submitted by National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Coalition to Protect America's National Parks, Appalachian Mountain Club, Western Environmental Law Center and Earthjustice, to former EPA Administrator Andrew Wheeler (May 8, 2020). ("Conservation Organizations Petition"). (Enclosure 5)

the date of this comment letter, EPA has not responded to the Petition. Until the current EPA Administration withdraws the illegal approaches in the 2019 guidance, we trust states will not follow it, instead adhering closely to the regulation itself and working to achieve the Clean Air Act goal of Class I visibility restored to natural conditions. The Petition explained that, as issued, the Final Guidance conflicts with this statutory objective, previous rulemaking and guidance; misdirects states as to how they can go about complying with their legal obligations to make reasonable progress towards restoring natural visibility to protected public lands; and otherwise fails to set expectations that comport with legal requirements for the second planning period.[27] The Petition includes a detailed analysis of the issues. As of the date of this comment letter, EPA has not responded to our Petition. Until the current EPA withdraws the illegal approaches in the 2019 guidance, we trust states will not follow it instead adhering closely to the regulation itself and work to achieve the Clean Air Act goal of Class I visibility restored to natural conditions.

### C. EPA's 2021 Clarification Memorandum

On July 9, 2021, EPA issued a memorandum titled, "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period."[28] EPA's July 2021 Memo provides important information regarding development of SIPs for all states for the regional haze second planning period in response to questions and information EPA is receiving from states and stakeholders and clarifies and provides information on existing statutory and regulatory requirements.[29] Because EPA's Memo is directly relevant to—and in some cases, confirms—numerous flaws in the Ecology's proposed SIP, as explained below and in the attached technical report, we urge Ecology to reevaluate its proposed SIP. We strongly encourage Ecology to take the time necessary to carefully review and consider all the information in EPA's July 2021 Memo and develop supporting information and make necessary adjustments to its proposed SIP.

Particularly relevant here, EPA made clear that States must secure additional emission reductions that build on progress already achieved, there is an expectation that reductions are additive to ongoing and upcoming reductions under other CAA programs.[30] In evaluating sources for emission reductions, EPA emphasized that:

> Source selection is a critical step in states' analytical processes. All subsequent determinations of what constitutes reasonable progress flow from states' initial decisions regarding the universe of pollutants and sources they will consider for the second planning period. States cannot reasonably determine that they are making reasonable progress if they have not adequately considered the contributors to visibility impairment. Thus, while states

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[27] Further, we petitioned the prior Administrator to replace it with guidance that comports with the Clean Air Act ("CAA") and the Regional Haze Rule, 42 U.S.C. §§ 7491, 7492; 82 Fed. Reg. 3078 (Jan. 10, 2017); 71 Fed. Reg. 60,612 (Oct. 13, 2006); 70 Fed. Reg. 39,104 (July 6, 2005); 64 Fed. Reg. 35,714 (July 1, 1999), and aids states in making progress towards achieving the national goal of natural visibility conditions at all Class I areas. Conservation Organizations Petition at 1-2.

[28] EPA Memorandum from Peter Tsirigotis, Director, Office of Air Quality Planning and Standards, to Regional Air Division Directors, "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period," (July 9, 2021) ("EPA July 2021 Memo"), https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation.

[29] *Id.*

[30] *Id.* at 2.

have discretion to reasonably select sources, this analysis should be designed and conducted to ensure that source selection results in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[31]

Thus, it is generally not reasonable to exclude from further evaluation larger sources of visibility-impairing pollution. Moreover, a state's obligation to consider the statutory reasonable progress factors for a particular source is not discharged simply because another source or another state has greater contributions to visibility impairment.[32] Ecology's sole focus on refineries is an example of such myopic decision making.

In sum, EPA's July 2021 Memo unequivocally states that meaningful reductions are expected to make reasonable progress towards the national goal of restoring visibility – reductions in $SO_2$ and NOx, reductions in the biggest sources of impairment as well as relatively smaller contributors – reductions that are achievable looking across a full spectrum of options of emission reducing measures. That the Ardagh Glass facility is absent from Ecology's analysis and reduction requirements is notable, for example, and on its face at odds with the state's haze obligations. EPA's memo is responsive to observations of state process and should result in redirecting Washington towards compliance with the CAA. State efforts to avoid reductions - to assert that because visibility has improved, because reductions are anticipated at some later date when the state works on the next SIP or due to implementation of another program, or because a source has some level of control are not acceptable excuses and neither is ignoring requests of FLMs and other states to assess sources for reductions. Actual requirements for emission reductions are expected for a haze SIP to be approvable in the absence of rare circumstances and this recent regional haze memo makes this abundantly clear.

### D. Requirements for Sources with Permits

We provide the following comments regarding RP requirements pertaining to facilities with permits. While a facility requested a permit to install emission controls, the permit does not exempt it from a four-factor analysis and establishment of emission limits to provide reasonable progress towards the national visibility goal. For example, Ecology must conduct a proper four-factor analysis for the Cardinal FG Winlock Glass Plant and ensure that emission limits are imposed via SIP measures to address the facility's visibility impairing pollution.

For a source that is found subject to the required reasonable progress Four-Faction Analysis as a result of a state's reasonable progress screening process, the state must ensure the Analysis is conducted. Neither the Act nor EPA's rules provide an "off-ramp" for a source in this situation.

A RACT analysis that Ecology may have gone through (or will go through in the future) for an individual source or source category is separate and distinct from the four-factor reasonable progress analysis requirement. The regional haze program includes identifying and issuing requirements to remedy *existing* impairment and also requirements necessary to prevent *future* impairment. As discussed below, the four-factor RP and RACT analysis apply different factors and consider different information because they are different programs with different objectives.

[31] *Id.* at 3.
[32] *Id.* at 7.

A RACT analysis and controls must not be used in place of the requirement to conduct the four-factor RP analysis and determine RP for the source. The regional haze four-factor RP analysis and determination applies *in conjunction with* other CAA programs. Therefore, as individual sources and source categories are modified and subject to emission controls (*e.g*., RACT), Ecology must take into consideration *all* requirements of the CAA (*e.g*., RP four-factor analysis and determination) and not set aside distinct requirements or delay their implementation. Moreover, a state's issuance of a permit does not replace its responsibility under the CAA to conduct the required RP four-factor analysis.

### E. If a Source is Unwilling to Conduct the Required RP Analysis, the Responsibility Must be Met by the State

The duty to ensure reasonable progress requirements are met for purposes of the SIP rests with the state, not the source. Therefore, if a source is unwilling to prepare the analysis, Ecology must conduct the analyses to inform its reasonable progress determination. Ecology fails to provide any authority or analysis for this "do nothing" approach.

For sources where the Q/d value shows a Four-Factor Analysis is required, Ecology must conduct the required four-factor analysis for the source, including requirements for emission limitations and other measures based on the source's current operations.

### F. Ecology Cannot Rely on Permit Provisions, Emission Reductions Must be Included in Practically Enforceable SIP Measures

Ecology cannot merely rely on permit provisions for emission reductions. The Clean Air Act requires states to submit implementation plans that "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of achieving natural visibility conditions at all Class I Areas.[33] The RHR requires that states must revise and update its regional haze SIP, and the "periodic comprehensive revisions must include the "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress as determined pursuant to [51.308](f)(2)(i) through (iv)."[34] Furthermore, EPA's Guidance further explains these requirements:

> This provision requires SIPs to include enforceable emission limitations and/or other measures to address regional haze, deadlines for their implementation, and provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.[35]

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[33] 42 U.S.C. §§ 7491(a)(1), (b)(2).
[34] 40 C.F.R. § 51.308(f)(2); 40 C.F.R. § 51.308(d)(3)(v)(F) (Enforceability of emission limitations and control measures).
[35] "EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," at 42-43 (Aug. 20, 2019), https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf. (While NPCA filed a Petition for Reconsideration regarding EPA's issuance of the 2019 Guidance, it does not dispute the information in the Guidance referenced here regarding enforceable limitations, which cite to the "General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990, 74 Fed. Reg. 13498 (April 16, 1992).

Thus, EPA's Guidance recognizes EPA's long-standing position that while the SIP is the basis for demonstrating and ensuring state plans meet the regional haze requirements, state-issued permits must complement the SIP and SIP requirements.[36] State-issued permits must not frustrate SIP requirements.[37] For example, sources with PSD permits under Title I must not hold permits that allow emissions that conflict with SIP requirements.[38] Additionally, the Act's Title V operating permits collect and implement all the Act's requirements – including the requirements in the SIP – as applicable to the particular permittee. And sources with Title V permits must not hold such permits if they contain permit terms and conditions that conflict with the SIP and Clean Air Act SIP requirements.

### G. It is Inconsistent with the CAA's Requirements to Use Air Quality Modeling to Decide Reasonable Process Controls

As explained above the reasonable progress four-factor analysis includes consideration of the following:

- Consider 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 sources.[39]

The four-factor analysis is clearly bounded by the information collected under each of the factors. Air quality impacts, modeling results, and emission inventories are not information collected pursuant to any of the four-factors. Therefore, to the extent a state adds an additional factor or factors to its four-factor analysis the state's analysis is inconsistent with the four-factor analysis requirement. As discussed in these comments, as part of its reasonable progress analysis Ecology uses visibility impacts to reject emission controls at several of the sources, and because visibility is not one of the four statutory factors, and EPA has expressly stated that consideration of visibility is not to be used as an offramp for reduction requirements, the State cannot rely on it to exclude emission reducing measures from a source that otherwise satisfies the four statutory factors.

### H. EPA Cannot Approve Ecology's Reliance on State-RACT to Meet the CAA's RP Requirements

Regional Haze Rule 40 C.F.R. 51.308(f) requires the state's long-term strategy to include all measures that are "necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)." In turn, 40 CFR 51.308(f)(2)(i) requires the state to consider the

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[36] 74 Fed. Reg. 13498, 13568 (April 16, 1992).

[37] Furthermore, to the extent stationary source are granted permits by rule or other mechanisms, these other categories that allow construction and operation must also complement SIP requirements.

[38] Additionally, the proposed SIP revisions fail to contain source-specific "measures to mitigate the impacts of construction activities." 40 C.F.R. § 51.308(d)(3)(v)(B).

[39] 42 U.S.C. § 7491(g)(1); 40 C.F.R. 51.308(f)(2)(i).

following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- 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. State-RACT is Not Equivalent to the CAA's RP Four-Factor Requirements

Ecology's suggestion that Washington State RACT "is equivalent to the" Regional Haze Rule's four-factor analysis is incorrect. Based on the plain language in Washington's statute for RACT – the five-factor State-RACT is neither equivalent to nor more stringent than the Clean Air Act's RP four-factor analysis. Thus, despite Ecology's meager assertions, it cannot use its State-RACT process to comply with the Act's reasonable progress requirements.

Ecology's draft SIP lists the four-factors applied for RP and the five-factors it applies for State-RACT.[40] The draft SIP includes a brief discussion of each of the four RP factors and shoe-horns State-RACT into each of the RP factors as follows, concluding that "…Ecology will use the RACT process to (1) evaluate and determine the emissions reduction measures that are necessary to make reasonable progress and (2) incorporate these measures into its long-term strategy and Regional Haze SIP in a manner that is enforceable as a legal and practical matter."

**Figure 1. Issues with Ecology's Draft SIP Analysis of State-RACT**

| Reasonable Progress Factor | Ecology Draft SIP Analysis | Issues with Ecology's Analysis |
|---|---|---|
| **The costs of compliance** | Under the RACT analysis, Ecology characterizes and considers the cost of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. The cost of compliance factor in 40 CFR 51.308(f)(2)(i) directly correlates to the RACT analysis consideration of capital and operating costs of the additional controls. The capital and operating costs in RACT are for purchase, installation, and operation of all equipment. These costs include the actual emission control equipment, any non-air quality equipment, and the energy costs to operate the equipment.[41] | State-RACT requires consideration of "capital and operating costs of the additional controls." While Ecology asserts that it has authority to consider "any non-air quality equipment, and the energy costs to operate the equipment" it does not cite language in its enabling statute or rules. Moreover, "any non-air quality equipment, and the energy costs to operate the equipment" is clearly not the same as the RP factor that |

[40] Draft SIP at 163-164.
[41] *Id*. at 164.

| Reasonable Progress Factor | Ecology Draft SIP Analysis | Issues with Ecology's Analysis |
|---|---|---|
| | | requires consideration of "energy and non-air quality environmental impacts of compliance." |
| **The time necessary for compliance** | Under the RACT analysis, Ecology characterizes and considers the time necessary for compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Under the RACT analysis requirements, Ecology determines the time necessary for compliance as part of considering the capital and operating costs of the additional controls and impact of the source upon air quality. Specifically, a shorter amount of time for compliance would involve costs distributed over a shorter time and thus have a larger annualized cost. The impact of the source on air quality is also a consideration in the time for compliance. The longer it takes to install and operate the control equipment the greater the negative impact on air quality.[42] | The State-RACT factors do not contain a time component. While Ecology suggests that it has authority to consider this RP factor as part of the costs analysis, it does not provide a cite to and an interpretation of the language it relies on to support its assertion.<br><br>Moreover, Ecology's suggestion that the time for compliance addresses air quality is not part of the Act's four-factor requirements. |
| **The energy and non-air quality environmental impacts of compliance** | Under the RACT analysis, Ecology characterizes and considers the energy and non-air quality environmental impacts of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the energy and non-air quality environmental impacts of compliance factor as part of analyzing the capital and operating costs of the additional controls in the RACT analysis. The RACT analysis includes costs for equipment directly related to the emissions and all indirectly required equipment needed to install and operate the new controls. The operating cost requirement in the RACT analysis also covers the energy impacts of the controls and supporting equipment.[43] | The State-RACT factors do not contain consideration of energy and non-air quality environmental impacts. While Ecology suggests that it has authority to consider this RP factor as part of the costs analysis, it does not provide a cite to and an interpretation of the language it relies on to support its assertion. Contrary to Ecology's assertions, the costs for "indirectly required equipment needed to install and operate the new controls" is not what is contemplated in the "energy and non-air quality environmental impacts of compliance." Indirectly required equipment |

[42] *Id.*
[43] *Id.*

| Reasonable Progress Factor | Ecology Draft SIP Analysis | Issues with Ecology's Analysis |
|---|---|---|
| | | is not the same as energy and non-air quality requirements, it does not have an equivalent reach. |
| **The remaining useful life** | Under the RACT analysis, Ecology characterizes and considers the remaining useful life of any potentially affected anthropogenic source of visibility impairment consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the remaining useful life of an emissions control system as part of calculating the capital and operating costs of the system. Specifically, the annualized costs of the emissions control system are affected by the remaining useful life. The shorter the useful life, the larger the annual costs associated with control equipment.[44] | The State-RACT factors do not contain consideration of the remaining useful life. While Ecology suggests that it has authority to consider this RP factor as part of the costs analysis, it does not provide a cite to and an interpretation of the language it relies on to support its assertion. |

Ecology admits that State-RACT "requires consideration of the impact of the source upon air quality [45] and then conflates consideration of visibility impacts as its equivalent asserting that this consideration is an element within the four-factor analysis requirements.[46] This it cannot do. Ecology's draft SIP analysis fails to show how the five State-RACT factors are equivalent or more stringent than the CAA's four-factor analysis, which as shown below, it cannot do. The

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[44] *Id.*
[45] *Id.*
[46] *Id.* at 164-165 ("Additionally, RACT requires consideration of the impact of the source upon air quality.' This is consistent with the CAA, RHR, and EPA guidance. While the four statutory factors must be considered in determining what is necessary to make reasonable progress, they are not the only factors that states may consider in this evaluation. As explained by EPA in its 2019 guidance, states have the flexibility to consider other factors, including visibility benefits, when determining the emission reduction measures that are necessary to make reasonable progress:

> 'Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered. Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. Likewise, it is reasonable that such information on visibility benefits be considered in light of other factors that may weigh for or against the control at issue. Such a balancing of outcomes is consistent with CAA section 169A(b)(2), which states that SIPs must contain elements as may be necessary to make reasonable progress toward meeting the national visibility goal. Thus, EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress.'" Citing, EPA-457/B-10-003, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, Section II.B.5.*)*

State’s RACT factors and applicability differ significantly from the CAA, thus Ecology’s draft SIP and attempt to rely on State-RACT now – and for future SIPs – is not approvable by EPA.

**Figure 2. Analysis Showing State-RACT is Noe Equivalent to the Required Four-Factor Analysis**

| | **CAA Reasonable Progress** | **Washington State-RACT** | **Are they Equivalent?** |
|---|---|---|---|
| **Applicability & Purpose** | The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources.[47]<br><br>***Purpose.*** The primary purposes of this subpart are to require States to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution; and to establish necessary additional procedures for new source permit applicants, States and Federal Land Managers to use in conducting the visibility impact analysis required for new sources under § 51.166. This subpart sets forth requirements addressing visibility impairment in its two principal forms: “reasonably attributable” impairment (*i.e.*, impairment attributable to a single source/small group of sources) and regional haze (*i.e.*, widespread haze from a multitude of sources which impairs visibility in every direction over a large area)[48] | RACT requirements.<br>(1) RACT as defined in RCW 70A.15.1030 is required for existing sources except as otherwise provided in RCW 70A.15.3000(9).<br>(2) RACT for each source category containing three or more sources shall be determined by rule except as provided in subsection (3) of this section.<br>(3) Source-specific RACT determinations may be performed under any of the following circumstances:<br>(a) As authorized by RCW 70A.15.2220;<br>(b) When required by the federal clean air act;<br>(c) For sources in source categories containing fewer than three sources;<br>(d) When an air quality problem, for which the source is a contributor, justifies a source-specific RACT determination prior to development of a categorical RACT rule; or<br>(e) When a source-specific RACT determination is needed to address either specific air quality problems for which the source is a significant contributor or source-specific economic concerns. | No |
| **Definition** | | Reasonably available control technology" (RACT) means the lowest emission limit that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and | |

[47] 40 C.F.R. § 308(f)(2)(i).
[48] 40 C.F.R. § 51.300(a).

| | CAA Reasonable Progress | Washington State-RACT | Are they Equivalent? |
|---|---|---|---|
| | | economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account…[49] | |
| **Factors** | Costs of compliance[50] | Capital and operating costs of the additional controls | Yes |
| | Time necessary for compliance | | No |
| | Energy and non-air quality environmental impacts of compliance | | No |
| | Remaining useful life of any potentially affected anthropogenic source of visibility impairment. | | No |
| | | Emission reduction to be achieved by additional controls | No. This is inherent in the RP analysis but not a specific factor that is considered and applied. |
| | | the availability of additional controls | Yes. Inherent in the RP analysis. |
| | | the impact of additional controls on air quality[51] | No. Not one of the four RP factors. This consideration can be integrated as part of the "non-air quality and environmental impacts of compliance" factor in a |

[49] RWC 70A.15.1030(20) (definition of RACT) ("Reasonably available control technology (RACT) means the lowest emission limit that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls. RACT requirements for a source or source category shall be adopted only after notice and opportunity for comment are afforded.")

[50] 40 C.F.R. § 308(f)(2)(i).

[51] RWC 70A.15.1030(20).

| | CAA Reasonable Progress | Washington State-RACT | Are they Equivalent? |
|---|---|---|---|
| | | | Four-Factor Analysis. |
| | | the impact of the source upon air quality[52] | No.<br>Not one of the four RP factors |

While Ecology's RACT provisions and the Clean Air Act's reasonable progress requirements have similarities, one is not a replacement for the other. Moreover and as discussed in detail below, application of the RACT requirements does not produce the results necessary to satisfy regional haze obligations. RACT introduces considerations that are not part of the reasonable progress Four-Factor Analysis and omits considerations that are. Consequently, and setting aside the lack of parity between the state and federal regulatory provisions, the outcome is a SIP that is deficient in meeting the programmatic objective: requirements for emission reduction measures that contribute to making reasonable progress towards the restoration of natural visibility at Class I areas progressively in each planning period.

### J. Ecology Can Use Its Existing Authority to Implement the Four-Factor Analysis Requirements

The Washington State legislature granted Ecology various legal tools to require controls on its sources,[53]several of which it could rely on to implement the Clean Air Act's Four-Factor Analysis requirements. For example, the Department of Ecology has broad authority under state law to propose and adopt emission limitations that apply to individual sources. The State Legislature outlined the powers and duties of the Department of Ecology in RCW 70A.15.3000, which includes the authority to

[52] RWC 70A.15.1030(20).

[53] Ecology has had many years to develop this SIP and select appropriate existing authority to meet the RP four-factor analysis requirements. Options of viable State authority include: (1) Adopt source-specific RP emission limitations via rulemaking using its authority under State law; (2) Have the local air pollution authorities (or Ecology) adopt new enforceable orders. This was done for the State's $PM_{10}$ nonattainment SIP, where the local agency established emission limitations and other requirements based on the modeling assumptions in Orders. Notably, the emission limitations were not LAER-based. *See* EPA's actions on the following three SIPs, Kaiser Aluminum (62 Fed. Reg. 3800 (Jan. 27, 1997) (final action), 61 Fed. Reg. 35998 (July 9, 1996) (proposal)); Saint Gobain (69 Fed. Reg. 53007 (Aug. 31, 2004) (final action), 69 Fed. Reg. 17368 (April 2, 2004) (proposal)); and Lafarge (69 Fed. Reg. 53007 (Aug. 31, 2004) (final action), 69 Fed. Reg. 17368 (April 2, 2004) (proposal)); (3) Adopt a RP regulation under State law using either its emergency or expedited rulemaking authority, and then adopt source-specific RP emission limitations via rulemaking under the newly adopted RP regulation; (4) Adopt a state-wide guideline, and have the sources submit plans to either Ecology or local air pollution authority to meet the guideline, which are reviewed and approved and included in the SIP submitted to EPA. *See* Simplot example (70 Fed. Reg. 22597 (May 2, 2005) (final), 70 Fed. Reg. 5086 (Feb. 1, 2005) (proposal)); (5) Include the required emission limitations and other requirements via a Title V permit, and then incorporate those provisions in the SIP for submittal to EPA for inclusion as source-specific requirements. *See* Boise Cascade example (70 Fed. Reg. 22597 (May 2, 2005) (final), 70 Fed. Reg. 5086 (Feb. 1, 2005) (proposal)); (6) Revise existing BART and other Orders issued in the State. This option is based on Ecology's modification of the BART Order issued for TransAlta, which it proposes to modify for the second planning period; (7) Seek delegation from EPA for whatever legal authority it thinks it lacks to implement the RP requirements; (8) Notify EPA it lacks authority and defer to EPA's promulgation of a FIP.

- *Adopt rules establishing* air quality objectives and *air quality standards*.[54]

- *Adopt by rule* air quality standards and *emission standards for the control* or prohibition of emissions to the outdoor atmosphere of radionuclides, dust, fumes, mist, smoke, other particulate matter, vapor, gas, odorous substances, or any combination thereof.[55]

In adopting these standards, the Legislature made clear that "[t]he air quality standards and emission standards may be for the state as a whole *or may vary from* area to area or *source to source*…"[56] The definition of emission standard includes requirements under both State and Federal law.[57]

The State Legislature also granted the Department authority to establish rules for a particular source that are more stringent than the statewide rules that apply to that source.[58] The Department must find that the regulation is "in the public interest" and "for the protection of the welfare of the citizens of the state," and "after public hearing and due notice" it may "may adopt and enforce rules to control and/or prevent the emission of air contaminants from such source." [59]

Ecology also has authority to issue a source-specific "regulatory order to an air contaminant source which applies to that source, any applicable provision of chapter 70.94 RCW [Washington's Clean Air Act], or the rules adopted thereunder."[60] If Ecology were to promulgate source-specific RP emission limitations, as it should, it could then issue regulatory orders to those sources, because there would be a specific rule that applied to each source. Furthermore, it would be inconsistent with the Washington State Legislature's declaration for Ecology to apply State-RACT, which is inconsistent and less stringent than the federal Clean Air Act's RP requirements. Notably, the Legislature declared that it is:

> [T]he policy of the state of Washington through the department of ecology to cooperate with the federal government in order to insure the coordination of the provisions of the federal and state clean air acts, and the department is authorized and directed to implement and enforce the provisions of this chapter in carrying out this policy …. [t]o take all action necessary to secure to the state the benefits of the federal clean air act.[61]

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[54] RCW 70A.15.3000(2)(a) (emphasis added).
[55] RCW 70A.15.3000(2)(c) (emphasis added).
[56] RCW 70A.15.3000(3).
[57] RWC 70A.15.1030 (12) "'Emission standard' and 'emission limitation' mean a requirement established under the federal clean air act or this chapter that limits the quantity, rate, or concentration of emissions of air contaminants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice, or operational standard adopted under the federal clean air act or this chapter."
[58] RCW 70A.15.3080.
[59] *Id.*
[60] Chapter 70.94 RCW.
[61] RCW 70A.15.1090(2).

Finally, the State Legislature gave Ecology overarching authority to establish emission limitations for sources subject to the Federal Clean Air Act's four-factor requirements. Specifically, Washington's Legislature:

> …[D]eclared to be the public policy to preserve, protect, and enhance the air quality for current and future generations. Air is an essential resource that must be protected from harmful levels of pollution. Improving air quality is a matter of statewide concern and is in the public interest. It is the intent of this chapter to secure and maintain levels of air quality that … comply with the requirements of the federal clean air act … foster the comfort and convenience of Washington's inhabitants, to promote the economic and social development of the state, and to facilitate the enjoyment of the natural attractions of the state.
>
> It is further the intent of this chapter to protect the public welfare, to preserve visibility, to protect scenic, aesthetic, historic, and cultural values, and to prevent air pollution problems that interfere with the enjoyment of life, property, or natural attractions. To these ends it is the purpose of this chapter to safeguard the public interest through an intensive, progressive, and coordinated statewide program of air pollution prevention and control, to provide for an appropriate distribution of responsibilities, and to encourage coordination and cooperation between the state, regional, and local units of government, to improve cooperation between state and federal government, public and private organizations, and the concerned individual, as well as to provide for the use of all known, available, and reasonable methods to reduce, prevent, and control air pollution.[62]

This enabling language is broader than State-RACT that is just based on "known, available, and reasonable methods" because reasonable progress does not limit emission reduction measures to consideration of "reasonable" but also includes consideration of the best and most stringent controls. Thus, the Department has authority under State law to establish air quality standards and emission limitations for a source category and individual sources using the rulemaking process, including the reasonable progress four-factor analysis requirements.
Indeed, Ecology discussed several of these options in its December 2020 public presentation on regional haze:[63, 64] taking no action; Agreed Orders; Compliance Orders;[65] permit modifications;

[62] Declaration of public policies and purpose of Washington's Clean Air Act, RWC 70A.15.1005.
[63] Philip Gent & Colleen Stinson, Washington Department of Ecology, Regional Haze State Implementation Plan (SIP) Public Information Session, at 41 (Dec. 3, 2020), https://ecology.wa.gov/DOE/files/87/8754c215-7a67-4e6f-bc9f-54632357913e.pdf. ("Ecology PPT"); s*ee also*, 2010 RH SIP, revised in 2012, https://apps.ecology.wa.gov/publications/SummaryPages/1002041.html.
[64] Ecology PPT at 40.
[65] It appears that historically the State may have used this authority to issue orders for sources in nonattainment areas that required emission limitations. *Note*, these orders did not establish LAER emission limitations..

and State-RACT.[66, 67] Thus, despite numerous options for State authority to implement the required RP four-factor analysis and emission control requirements, Ecology's proposed SIP impermissibly sets aside this Clean Air Act requirement with an alternative standard that fails to satisfy it.

## IV. Source-Specific Control Measures

### A. TransAlta Centralia Generation

The TransAlta Centralia Generating Station is a coal-fired power plant located near Centralia, Washington. In its 2010 Regional Haze SIP, Ecology indicated that the Centralia plant significantly impacts regional haze in twelve Class I areas in Washington and Oregon.[68] The Centralia power plant was subject to BART in Washington's regional haze plan. In 2003, EPA approved requirements applicable to the Centralia units' $SO_2$ and PM emissions as meeting BART.[69] In 2012, EPA approved a NOx BART determination in First Revised BART Order 6426 for the Centralia power plant, which included the following control requirements: an initial NOx emission limitation of 0.21 lb/MMBtu for each unit based on the installation of SNCR on both coal-fired units plus Flex Fuel followed by an optimization study and lowering of the emission limits based on the study results.[70] In addition, the BART order required each of the two Centralia units to cease burning coal and be "decommissioned" by December 31, 2020 for one unit and by December 31, 2025 for the other unit, unless Ecology determined that state or federal law requires selective catalytic reduction (SCR) to be installed on either unit.[71]

In 2021, EPA approved a revision to the BART requirements for the Centralia power plant.[72] Specifically, TransAlta had installed a Combustion Optimization System with Neural Network

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[66] "This state law usually allows the sources a specific amount of time to upgrade the controls to meet the new or revised emission standards. It includes an economic hardship provision. A company that demonstrates it meets the criteria for economic hardship is allowed either an extended time to achieve compliance or an alternate, source-specific emission limitation." Regional Haze SIP Revision – Second 10-Year Plan Table of Contents Chapter 9: Reasonable Progress Goals at 4 (Sept. 2020) ("Sept. 2020 SIP Revision, Chapter 9"), https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/docs/RhSIPCh09202009.pdf.

[67] In addition to applying RACT to existing sources, Ecology explains that it applies to new sources and modifications, "[s]tate law (RCW 70A.15.2220) requires that when a company decides to modify or replace an existing emission control system, Ecology or the local air pollution control authority must assure that the modified or replacement control system meets a reasonably available control technology (RACT) level of emissions control. This results in an emission reduction from the stationary source, though not so dramatic a reduction as might be achieved through the NSR program. Processing modifications and replacements of control equipment is an ongoing workload and, from year-to-year, the emission reductions are unpredictable." Regional Haze SIP Revision – Second 10-Year Plan Table of Contents Chapter 10: Long-Term Strategy For Visibility Improvement, at 10 (Sept. 2020) ("Sept. 2020 SIP Revision, Chapter 10"), https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/docs/RhSIPCh10202009.pdf.

[68] Stamper Report at 9.

[69] WDOE, Regional Haze Plan, (Dec. 2010), at 11-13 (Table 11-11), https://apps.ecology.wa.gov/publications/documents/1002041.pdf.

[70] *See* 68 Fed. Reg. 34821 (June 11, 2003).

[71] *See* 77 Fed. Reg. 72742 (Dec. 6, 2012); *see also,* First Revised BART Order 6426, attached as Ex. 1 to Stamper Report.

[72] *Id.*

program (Neural Net) to decrease ammonia slip from the SNCR, and such Neural Net controls also help to reduce NOx emissions among other things. Ecology reduced the NOx limit applicable to one unit from to 0.18 lb/MMBtu and changed other requirements pertaining to use and monitoring of ammonia and analyzing coal sulfur and nitrogen content.[73] Ecology also eliminated the requirement in the BART Order 6426 that required that the units be "decommissioned" once they stopped burning coal, based on 2017 changes to a Memorandum of Agreement between TransAlta and the state of Washington.[74]

The Stamper Report explains that "[i]t appears that TransAlta has been pursuing a coal-to-gas conversion program at some of its other units in Canada."[75] Thus, in the event TransAlta elects to re-power with natural gas, Ecology's reliance on the retirements for its 2028 emission projections would be misplaced and need a revision to the SIP. Furthermore, a re-powering scenario would be subject to regional haze BART requirements, including SIP public notice and comment, amongst other Clean Air Act requirements. Notably, one of the other Clean Air Act requirements such a proposed SIP amendment where TransAlta proposed to transitions to gas would be subject to is the anti-backsliding provisions, which are discussed in detail below in Section VII.B.

### B. Alcoa Primary Metals Intalco Works and Alcoa Wenatchee

While Ecology correctly identified Alcoa's two aluminum smelters as sources that "have a very large potential to emit $SO_2$, and would contribute to regional haze if Alcoa re-started aluminum production operations,"[76] its proposed SIP lacks the required four-factor analysis and enforceable emission limits.

The Alcoa Primary Metals Intalco Works Plant (Intalco Plant) is an aluminum smelter located in Ferndale, Washington. NPCA found that the Alcoa Intalco plant potentially impacts 38 Class I areas and that it is the most significant industrial contributor to regional haze at North Cascades National Park.[77] Ecology states that the Intalco Plant has been in curtailment since 2020.[78] The Alcoa Wenatchee Plant is an aluminum smelter located in Wenatchee, Washington. …[T]he Wenatchee plant has a Q/d value of 80.9 based on 2014 emissions. According to NPCA's analysis, emissions from the Wenatchee plant potentially impact 34 Class I areas, including the Alpine Lakes Wilderness area,[79] located approximately 28 miles west of the facility, and also

[73] 86 Fed. Reg. 24502 (May 7, 2021).
[74] Ecology, Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision, July 2020, at i (attached as Ex. 2 to Stamper Report).
[75] Stamper Report at 13, citing https://www.nsenergybusiness.com/features/coal-gas-conversion-us-canada/.
[76] Draft SIP at 82.
[77] NPCA, Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), at 3.
[78] WDOE Public Review Draft, Second Regional Haze Plan, (Oct. 2021), at 82.
[79] 78 Fed. Reg. 79344, 79348-79349. (Dec. 30, 2013).

North Cascades National Park to the northwest and Mount Rainier National Park to the southwest.[80] Ecology states that the Wenatchee plant has been in curtailment since 2015.[81,82]

If Ecology is going to claim that controls at these two aluminum plants are necessary as part of its Long Term Strategy for the second implementation period - which is must - then the state's plan must include the requirements that would be imposed if either of the plants resume operation.[83] Such evaluations of the emission reduction measures necessary to make reasonable progress is required to be included in the long term strategy pursuant to 40 C.F.R. § 51.308(f)(2)(i).[84] Further, it would also give Alcoa notice as to the control requirements it must meet before it decides whether to restart either plant which would ensure expeditious limitations emissions should either plant restart.[85]

Furthermore, as discussed in NPCA's earlier comments to Ecology on the Agreed Orders for the two smelter sources, there are numerous approvability issues with the Orders.[86]

### C. Ash Grove Cement Plant

Ecology selected the Ash Grove Cement Plant as a facility to be included in its Long Term Strategy in its regional haze plan for the second implementation period because it is one of the largest NOx point sources in Washington, emitting over 1,000 tons of NOx per year.[87] And yet, the draft SIP lacks the required four-factor analysis and emission limits to control emissions. The source is a dry process cement kiln in the Duwamish Industrial area of Seattle and the primary regional haze pollution from the plant comes from the cement kiln and its associated clinker cooler baghouses.[88] It is located only 53.8 kilometers from Alpine Lakes Wilderness Area[89] and, according to NPCA, potentially impacts nine Class I areas.[90] The source has a Q/d value based on 2014 emissions of 23.1. According to Ecology, the source is capable of burning coal, natural gas, and tire-derived fuels.[91]

There are numerous issues with Ecology's approach in the proposed SIP.[92] First, although Ecology requested the required four-factor analysis for the Ash Grove Cement Plant,[93] The primary issue is that Ecology proposes to rely on a consent decree that lacks an emission limit

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[80] NPCA, Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), at 3.
[81] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 82.
[82] Stamper Report at 13-14.
[83] *Id.* at 17.
[84] *Id.*
[85] *Id.*
[86] Stamper Report at 14; NPCA, Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County).
[87] Draft SIP at 82.
[88] *Id.* at 167.
[89] *Id.* at 162.
[90] Based on NPCA's Regional Haze Fact Sheet for Washington, Sources of Visibility Impairing Pollution in Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[91] WDOE Public Review Draft, Second Regional Haze Plan, (Oct. 2021), at 167.
[92] 40 C.F.R. § 51.308(f)(2)(i).
[93] Draft SIP at 163.

and the limit proposed (5.1lb/ton) is too high for SNCR capabilities. Moreover, "Ecology has failed to provide an adequate [and complete] four-factor analysis of controls."[94] As discussed in detail in the Stamper Report, Ecology's abbreviated analysis is incomplete and fails to evaluate the control option of installing catalytic ceramic filters in the existing main baghouse at the cement kiln, which several vendors offer and claim can achieve 90% or greater control of NOx.[95] The Stamper Report further explains that:

> Recently, a cost assessment for the use of a ceramic catalytic filtration system was done for the GCC Pueblo Cement Plant in Colorado.[96] That information can be used to estimate costs of using a catalytic ceramic filtration system at the Ash Grove plant. The GCC plant is somewhat similar to the Ash Grove Seattle plant in that both cement kilns use the dry kiln process and use a preheater and precalciner.[97, 98]

The use of catalytic ceramic filters would allow for a NOx emission limit of approximately 0.5 lb/ton of clinker,[99] which is significantly lower than the 5.1 lb/ton clinker NOx limit that Ecology is proposing to be part of the state's Long Term Strategy.[100] Therefore, Ecology must fully evaluate use of catalytic ceramic filter bags at the Ash Grove cement plant as a top regional haze control.

Moreover, Ecology's attempted reliance on the 2013 Consent Decree is misplaced. The Consent Decree was not negotiated to meet the requirements of the regional haze program, nor can Ecology make such a demonstration. Ecology's attempt to rely on an approval letter from EPA in a completely different context to create enforceable SIP limits fails.

Additionally, Ecology must evaluate all control technologies, including SNCR, because as discussed in the Stamper Report, SNCR can most assuredly reduce NOx to lower emission rates than the 5.1 lb/ton of clinker emission rate that Ash Grove is apparently negotiating with PSCAA for its SNCR system.[101]

The proposed SIP also fails to impose appropriate emission limits and control requirements. Indeed, the draft SIP does not recommend installation of control equipment for particulate matter

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[94] Stamper Report at 19.

[95] *Id.* at 20; *see e.g.*, Klafka, Steve, Wingra Engineering, GCC Rio Grande – Pueblo Cement Plant, Four-Factor Reasonable Progress Analysis, September 23, 2021, hereinafter GCC Pueblo Four-Factor Analysis, attached as Ex. 5 to Stamper Report.

[96] Klafka, Steve, Wingra Engineering, GCC Rio Grande – Pueblo Cement Plant, Four-Factor Reasonable Progress Analysis, (Sept. 23, 2021) ("GCC Pueblo Four-Factor Analysis") attached as Ex. 5 to Stamper Report.

[97] *See* GCC Pueblo Four-Factor Analysis, Appendix B at 2 (Ex. 6 to Stamper Report); *see also* PSCAA Statement of Basis for Ash Grove Cement Company, Air Operating Permit Administrative Amendment 4 issued 6/13/18 at 3 (Ex. 7 to Stamper Report).

[98] Stamper Report at 20.

[99] *See* PSCAA Statement of Basis for Ash Grove Cement Company, Air Operating Permit Administrative Amendment 4 issued 6/13/18, at 1 (Ex. 7 to Stamper Report); and Air Operating Permit No. 11339, issued to Ash Grove Cement Company by PSCAA, last amended June 13, 2018, at 10 (Ex. 8 to Stamper Report). Assuming 90% NOx control from the 1,846 tons NOx per 12-month period limit equates to 0.5 lb/ton of clinker at maximum production capacity of 750,000 tons of clinker per year.

[100] Stamper Report at 21-22.

[101] Draft SIP at 168.

because of what it claims are recent upgrades; and asserts the costs for SCR for NOx and wet scrubbing for $SO_2$ are unreasonable because of confined space at the site.[102] Ecology admits that the 5.1 lb/ton of clinker emission rate from the recent upgrade is not reflective of even full-time operation of an SNCR system, and yet proposes a 5.1 lb/ton NOx limit that purportedly requires SNCR for the facility in its Long Term Strategy with a plan to revise the regional haze plan once a permit for the SNCR system is issued by PSCAA. Ecology has not even provided evidence that the 5.1 lb/ton clinker NOx limit has been adopted in final enforceable form such that it can be incorporated into the federally enforceable SIP.

Ecology's apparent reliance on the fuel change to no longer burn coal as the method to reduce and control $SO_2$ emissions must be imposed as a federally enforceable SIP provision. Moreover, Ecology did not evaluate any controls for $SO_2$ and must evaluate use of catalytic ceramic filter with sorbent injection should also be evaluated as an available $SO_2$ control for the cement plant.[103]

Ecology must conduct a complete four-factor analysis now as part of its regional haze plan for the Ash Grove cement plant to fully evaluate all cost-effective controls and impose practically enforceable emission limits that apply at all times - not intermittently - for the pollutants that are reflective of the efficacy of the controls required.

### D. Cardinal FG Winlock Glass Plant

The Cardinal FG Winlock plant is a flat glass manufacturing plant in Winlock, WA. According to Ecology, its 2014 NOx emissions were 791 tons per year based on 2014 emissions.[104] Thus, the facility is a large source of NOx. Despite the large source of emissions, Ecology did not request a four-factor analysis of pollution controls for the Cardinal Glass Plant.[105] Instead, Ecology proposes to rely on the fact that the company recently submitted a permit application to install SCR controls, which it proposed concurrently with an increase in glass production capacity from 650 tons per day to 750 tons per day.[106] Ecology's proposed reliance on a permit that is in process to meet the regional haze reasonable progress requirements is misplaced.

As discussed in Section VIII.E, the regional haze four-factor analysis requirement applies to sources *in conjunction with* any other Clean Air Act requirements. The fact that the Cardinal Glass Plant may receive a permit that requires installation and use of SCR does not obviate the need for the state to comply with reasonable progress requirements.[107] Moreover, "[t]he emission limits of the permit, as described in the draft regional haze SIP, do not reflect the maximum capabilities of SCR, including the ability to use low temperature catalyst to avoid or eliminate the $SO_2$ and particulate matter increases that were projected to occur with SCR."[108]

[102] *Id.* at 171.
[103] Stamper Report at 22.
[104] Draft SIP at 84.
[105] Stamper Report at 23.
[106] Draft SIP at 171.
[107] Stamper Report at 25.
[108] *Id.*

Furthermore, in preparing the required four-factor analysis, Ecology must evaluate the engineering concerns and considerations presented in the Stamper Report. For example, the proposed NOx reductions only reflect a reduction with SCR of 68%, which is much lower than the 90%+ control SCR is capable of achieving.[109] Ecology has not explained why it is not requiring the more stringent controls, which can be achieved using the options described in the Stamper Report (*i.e.*, use of the 3R process, low temperature catalysts, and use of ceramic catalyst filters).[110]

Ecology must conduct its own four-factor analysis of reasonable progress controls. "The fact that the Cardinal Glass Plant has received a permit requiring installation of use of SCR does not obviate the need for the state to comply with reasonable progress requirements. The emission limits of the permit, as described in the draft regional haze SIP, do not reflect the maximum capabilities of SCR, including the ability to use low temperature catalyst to avoid or eliminate the $SO_2$ and particulate matter increases that were projected to occur with SCR."[111] Ecology must impose emission limits in its SIP.

## V. Unjustifiable Deferral of Reasonable Progress Requirements for Refineries and Pulp and Paper Facilities in Ecology's Proposed Long Term Strategy

### A. Oil Refineries

Ecology identified the refineries as the prior source sector in its proposed SIP. Despite requesting four-factor analyses from the sources, Ecology found the analyses were fraught with errors and conducted its own cost effectiveness analysis. Ecology identified cost effective controls and yet its proposed SIP fails to include enforceable emission limitations. Contrary to the Act and regional haze regulations, Ecology proposes to defer to address this source sector in the next planning period.

Ecology states in its draft regional haze plan that the refineries in Washington "are over 40 years old and the facilities have maintained the majority of the equipment in a manner that has not required updating emission controls to current standards."[112] Ecology did a nationwide comparison of 2014 facility-wide NOx emissions per barrel of production capacity for the five Washington refineries to 83 other refineries located in the U.S. and found that "Washington refineries represent four of the top five facilities in the nine states in terms of NOx emissions per 1,000 barrels produced per day."[113] Ecology requested four-factor analyses from the five Washington refineries to address each fluid catalytic cracking unit (FCCU), each boiler with heat input greater than 40 MMBtu/hr, and each heater with heat input greater than 40 MMBtu/hr that has not been retrofitted with NOx controls since 2005.[114] None of the five refineries for which Ecology requested four-factor analyses found that low NOx burners or ultra-low NOx burners

[109] Stamper Report at 24.
[110] *Id.* at 24.
[111] Stamper Report at 25.
[112] Draft SIP at 184.
[113] *Id.* at 185-186 (Table 7-6).
[114] *See*, e.g., BP Cherry Point Refinery Regional Haze Four Factor Analysis, (April 2020) ("BP Cherry Point Analysis") at 2, available at https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/RegionalHaze.htm.

(LNB/ULNB) or SCR were appropriate for regional haze reasonable progress controls. Therefore, Ecology correctly conducted its own cost effectiveness analyses for application of SCR to the refinery heaters and boilers. Ecology states that two refineries did not submit analyses for their FCCUs, and Ecology subsequently decided to evaluate SCR for those FCCUs "since they are a large source of NOx emissions."[115]

### 1. Ecology is Entirely Justified in Its Use of EPA's Control Cost Manual to Determine Cost Effective Controls for the Petroleum Refineries

Ecology is entirely justified to use and rely on the EPA's SCR cost spreadsheet to determine cost effectiveness of SCR at the heaters, boilers and FCCUs for the five refineries it evaluated for controls for its regional haze plan.[116] Ecology determined that SCR is cost effective for the refineries as seen in the below figure.

**Figure 3. Ecology's Identification of Cost Effective SCR Determinations at the Petroleum Refineries[117]**

| Plant | Emission Unit | Cost Effectiveness, $/ton | NOx Reduced, tons per year |
|---|---|---|---|
| BP Cherry Point | #1 Reformer Heaters | $3,101/ton | 304 tpy |
| | Crude Heater | $2,051/ton | 393 tpy |
| | Reforming furnace #1 (N H2 Plant) | $6,161/ton | 262 tpy |
| | Reforming furnace #2 (S H2 Plant) | | |
| Phillips 66 Ferndale | Crude Heater 1F-1 | $2,640/ton | 166 tpy |
| | FCCU/CO Boiler/Wet Gas Scrubber 4F-101 | $3,954/ton | 247 tpy |

115 Draft SIP at 187.
116 Stamper Report at 30, 27-30, 33.
117 Draft SIP at 188 (finding SCR at BP Cherry Point units was cost effective), at 192 (finding SCR at Phillips 66 units was cost effective), at 194 (finding SCR at Shell units was cost effective), and at 198 (fining SCR at Marathon Petroleum Company (Tesoro) units was cost effective); *see also* Appendix J at J-1.

| Plant | Emission Unit | Cost Effectiveness, $/ton | NOx Reduced, tons per year |
|---|---|---|---|
| Shell Puget Sound | Boiler #1 Erie City – 31G-F1 | $2,441/ton | 179 tpy |
| | FCCU Regenerator Unit | $1,948/ton | 521 tpy |
| | CRU #2 HTR, INTERHTR—10H-101, 102, 103 | $6,346/ton | 69 tpy |
| Marathon Petroleum Company (Tesoro) Anacortes Refinery | FCCU | $1,159/ton | 843.3 tpy |
| | F 102 Crude Heater | $2,962/ton | 147.6 tpy |
| | F 201 Vacuum Flasher Heater | $7,589/ton | 57.6 tpy |
| | F 6650 CAT Reformer Heater | $3,736/ton | 117 tpy |
| | F 6651 CAT Reformer Heater | $3,520/ton | 124.2 tpy |
| | F 751 Main Boiler | $2,159/ton | 202.5 tpy |
| | F 752 Main Boiler | $2,570/ton | 170.1 tpy |

However, instead of adopting SCR control requirements for the refinery emission units, Ecology's draft SIP suggests it will conduct a more extensive cost evaluation of SCR. The Stamper Report explains that additional analysis is not necessary because Ecology:

- Provided the refineries an opportunity to submit four-factor analyses;

- Determined that that the company analyses were not well documented or justified;[118]
- Used the proper EPA Control Cost Manual, which demonstrated that SCR is cost effective for the units;
- Correctly applied the other three factors and determined they do not provide a reason to exclude any of the emission units from requirement to install SCR to achieve reasonable progress towards the national visibility goal.[119]

As highlighted below and presented in the Stamper Report, there are numerous issues with the company's analyses. Therefore, Ecology is justified in correcting the identified deficiencies and in its final SIP submission requiring SCR as reasonable progress controls for all of the refineries. Indeed, because Ecology identified refineries as its priority sector for this planning period, it must require SCR and the associated emission limitations.

## 2. BP Cherry Point Refinery

The BP Cherry Point Refinery's four-factor analysis had numerous errors, which are inconsistent with the legal requirements. As discussed in the Stamper Report, Ecology rightly corrected the errors and in so doing determined that SCR is cost effective.

Ecology calculated a Q/d value for the BP Cherry Point facility of 36.4, and it is ranked 5th highest Q/d on Ecology's list of sources it evaluated.[120] NPCA data shows that the facility likely contributes to regional haze at 14 Class I areas.[121]

There are numerous issues with the company's four-factor analysis because it does not comport with EPA's regulations, guidance and is based on unsupported assumptions. The Stamper Report presents details on seven issues with the company's four-factor analysis:[122]

- Used an inflated interest rate in amortizing capital costs, which not consistent with EPA's Control Cost Manual;[123]
- Scaled 2010 cost estimates, which EPA's Control Cost Manual cautions against;[124]
- Unjustifiably rejected emission control options as not technical feasible;[125]
- Failed to include citations and support for statements regarding emission rates, retrofit factors, cost for ammonia reagent;[126]

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[118] *Id.* at 190, 192, 195, 196, 199, and 202 (Ecology stating that the various refinery companies provided limited supporting data for their cost analyses).
[119] Stamper Report at 33.
[120] Draft SIP at 161.
[121] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[122] Stamper Report at 34-36.
[123] *Id.* at 34.
[124] *Id.*
[125] *Id.* at 34-35.
[126] *Id.* at 35-36.

- Erroneously inflated the number of hours per year number based on the number of hours in a leap year;[127]
- Failed to assume the most cost-effective options for catalyst replacement;[128] and
- Unreasonably assumed a lengthy schedule to implement emission controls.[129]

Ecology's cost-effective analysis was based on EPA's SCR cost spreadsheet.[130] The differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and the company's are very significant, as discussed in the Stamper Report and shown in the below figure.

**Figure 4. Summary from Draft Washington Regional Haze SIP: Comparison of BP's Cost Analysis to Ecology's Cost Analysis for SCR at Certain BP Cherry Point Emission Units[131]**

| BP's Capital Cost | BP's Annual Maintenance Cost | BP's Cost Effectiveness, $/ton | WDOE's Capital Cost | WDOE's Maintenance Cost | WDOE's Cost Effectiveness | NOx Reduced, tpy |
|---|---|---|---|---|---|---|
| **Reformer Heaters** | | | | | | |
| $94,809,582 | $420,048 | $24,378/ton | $9,929,730 | $49,649 | $3,101/ton | 304 tpy |
| **Crude Heater** | | | | | | |
| $94,809582 | $420,048 | $24,378/ton | $9,325,358 | $46,627 | $2,051/ton | 425 tpy |
| **Hydrogen Plant Reforming Furnaces** | | | | | | |
| $143,325,183 | $479,126 | $78,065/ton | $9,325,358 | $46,627 | $6,161/ton | 141 tpy |

As the Stamper Report explains:

> BP's cost estimates are almost ten times as high as the SCR cost estimates for the same units calculated by Ecology with EPA's SCR cost spreadsheet. Ecology's analysis clearly shows that SCR at these BP Cherry Point units would be cost effective and would reduce NOx emissions by a total of 870 tons per year. Ecology states that BP did not

[127] *Id.* at 36.
[128] *Id.*
[129] *Id.*
[130] *Id.*
[131] *Id.* at 37, data from Draft SIP at 189-190 (Tables 7-8, 7-9, and 7-10).

> provide the data it used to scale the cost data. Thus, Ecology has found BP did not adequately support its SCR cost calculations.[132]

Furthermore, in 2018, attorneys representing Ecology told the State of Washington Pollution Control Board that Ecology would address emissions from BP Cherry Point in the Regional Haze Program. Explaining that the "National Park Service's finding of adverse impacts from the BP project" in that permit appeal case "will be included as a component of the next analysis of state's progress toward better visibility required by the Regional Haze Program."[133] During the Hearing before the Pollution Control Hearings Board, Ecology's Alan Newman testified and confirmed the statements in the Prehearing Brief. Mr. Newman testified that the Department would evaluate BP Cherry Point for "a SIP update and potential emission reduction requirements" as part of the 2021 regional haze plan.[134] Mr. Newman further testified that:

> BP will be evaluated, as other sources will, for whether there are available and appropriate controls that can be installed, and, if so, they will be required as part of the regional haze for reasonable progress goal for 2028.[135]

In its draft SIP Ecology found that controls are available and cost effective, yet, contrary to the Department's 2018 sworn testimony, Ecology proposes no controls in the draft SIP for the BP Cherry Point Refinery. Ecology cannot dodge its legal obligations to consider and control emissions impacting the Class I Areas in both the permitting *and* regional haze programs.[136] This, Ecology must include enforceable emission limitations for the BP Cherry Point refinery in this draft SIP to meet its earlier commitment and statements to its Board.

Moreover, to meet the requirements of EPA's regional haze regulations, Ecology must include final determinations to require SCR in this regional haze plan for the second implementation period for the BP Cherry Point Refinery.

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[132] Stamper Report at 37.
[133] *National Parks Conservation Association v. State of Washington, Department of Ecology; and BP West Coast Products, LLC*, PCHB No. 10-162, Department of Ecology's Prehearing Brief (April 12, 2018), at 5 (Enclosure 6);
[134] *National Parks Conservation Association v. State of Washington, Department of Ecology; and BP West Coast Products, LLC*, PCHB No. 10-162, Hearing Transcript, Volume IV (April 26, 2018), at 757 (testimony of Alan Newman at 757, ("Q So what does that mean in the regional haze program when you get an adverse determination, adverse impact determination? A If I considered it the same as an adverse impact determination under 51.302, that means the Washington State Department of Ecology has to evaluate that facility for a SIP update and potential emission reduction requirements. By the rule, that SIP update for this timing is allowed to occur as part of the 2021 regional haze plan.) (Enclosure 7).
[135] *Id.* at 806-807("Q Is it your position that if BP is affecting haze after this project, you will require controls to address that, you will require controls from BP to address that? A BP will be evaluated, as other sources will, for whether there are available and appropriate controls that can be installed, and, if so, they will be required as part of the regional haze for reasonable progress goal for 2028. I cannot give you an answer there will be a reduction. Q Based on what information? A Based on the analysis has not been started or completed. Q Does that include pollution controls that are equivalent to BACT as we are discussing here? A Those are the kind of controls that would be evaluated. Q Regional haze provisions don't address deposition, right? A That is correct.)
[136] As discussed elsewhere in these comments, the Clean Air Act's permit programs work in conjunction with the regional haze program.

### 3. Marathon Petroleum Company (MPC) Anacortes Refinery (Formerly Tesoro Refinery)

The MPC's four-factor analysis for the Tesoro Refinery had numerous errors, which are inconsistent with the legal requirements. As discussed in the Stamper Report, Ecology rightly corrected the errors and in so doing determined that SCR is cost effective.
The Anacortes Refinery is currently owned by Marathon Petroleum Company (MPC) and was previously owned by Tesoro Refining & Marketing Company LLC (Tesoro, which Ecology also refers to as "Tesoro Northwest Company"[137]). Ecology calculated a Q/d value for the Tesoro Anacortes Refinery of 30.7, and it is ranked 6th highest Q/d on Ecology's list of sources it evaluated.[138] NPCA data shows that the facility likely contributes to regional haze at 10 Class I areas.[139]

There are numerous issues with the company's four-factor analysis because it does not comport with EPA's regulations, guidance and is based on unsupported assumptions. Specifically, MPC:

- Did not conduct four-factor analyses for any heaters or boilers that had installed NOx controls since 2005.[140]
- Used outdated 2014 emissions for the baseline year contrary to EPA's regulation and guidance – and without justification;[141]
- Used an inflated interest rate contrary to EPA's Control Cost Manual;[142]
- Used an unjustified and very high cost for ammonia;[143]
- Failed to provide underlying data and assumptions for the FCCU analysis;[144]
- Failed to provide documentation and justification for the base case fuel gas volumetric flow rate factors for the SCR reactors;[145]
- Unreasonably assumed low NOx removal rate for Boiler 3 of 75%, without providing justification;[146]
- Only assumed a 20-year life of controls in determining the amortizing the capital costs of control for ULNB for the heaters and boilers;[147]
- Failed to provide justification for the NOx emission rate for the ULNBs;[148] and
- Failed to evaluate the cost effectiveness of the most effective control – ULNB plus SCR.[149]

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137 Draft SIP at 185.
138 *Id.* at 161.
139 NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
140 *Id.*, Appendix P at P-207 (Tesoro Four-Factor Analysis).
141 Stamper Report at 39.
142 *Id.*
143 *Id.* at 39-40.
144 *Id.* at 40.
145 *Id.*.
146 *Id.* at 40-41.
147 *Id.* at 41.
148 *Id.* at 41-42
149 *Id.* at 42.

**Figure 5. Comparison of SCR Cost Effectiveness as Calculated by Tesoro to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Anacortes Refinery**[150]

| Anacortes Refinery Emission Unit | Tesoro's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| FCCU | $14,381/ton | $1,159/ton | 843.3 tpy |
| F102 Crude Heater | $16,086/ton | $2,962/ton | 147.6 tpy |
| F201 Vacuum Heater | $35,276/ton | $7,589/ton | 57.6 tpy |
| F6650 CAT Reformer Heater | $21,196/ton | $3,736/ton | 117 tpy |
| F6651 CAT Reformer Heater | $21,196/ton | $3,520/ton | 124.2 tpy |
| F751 Main Boiler | $10,060/ton | $2,159/ton | 202.5 tpy |
| F752 Main Boiler | $10,513/ton | $2,570/ton | 170.1 tpy |

As discussed in the Stamper Report and seen in the above figure, "differences in calculated SCR costs/ton of NOx removed make clear that Tesoro's costs are significantly higher than the costs calculated by Ecology using the EPA SCR cost spreadsheet provided with EPA's Control Cost Manual."[151] Given that SCR is such a highly effective NOx control and otherwise satisfies the Four-Factor Analysis, the state should require SCR installation as reasonable progress for these units.

To meet the requirements of EPA's regional haze regulations, Ecology must include final determinations to require SCR in this regional haze plan for the second implementation period for the Marathon Petroleum Company Anacortes Refinery.

[150] Draft SIP at 199.
[151] Stamper Report at 42.

**4. Shell Puget Sound Refinery**

Shell Puget Sound Refinery's four-factor analysis had numerous errors, which are inconsistent with the legal requirements. As discussed in the Stamper Report, Ecology rightly corrected the errors and in so doing determined that SCR is cost effective.

The Shell Puget Sound Refinery is another refinery located near Anacortes, Washington. Ecology calculated a Q/d value for the Shell Puget Sound Refinery facility of 24.5.[152] NPCA data shows that the facility likely contributes to regional haze at eight Class I areas.[153]

There are numerous issues with the company's four-factor analysis because it does not comport with EPA's regulations, guidance and is based on unsupported assumptions. The Stamper Report presents details on seven issues with the company's four-factor analysis.[154] Specifically, Shell's analysis:

- Lacked justification for its baseline emission assumptions;[155]
- Used an unreasonably high interest rate of 7%, inconsistent with EPA's Control Cost Manual;[156]
- Used truncated useful life assumptions, inconsistent with EPA's Control Cost Manual;[157]
- Assumed an eight year remaining useful life for the highest emitting unit (Erie City Boiler 1);[158]
- Underestimated without justification the NOx emission rate for LNB;[159]
- Applied an inflated and unjustified retrofit factor;[160]
- Assumed costs for reheating the gas stream for each of the emission units at the Shell refinery to accommodate SCR, without providing justification.[161]

Ecology found that the Shell Puget Sound Refinery had the second highest NOx emissions per 1,000 bpd production of all of the eighty-four refineries nationwide that it evaluated.[162] As seen in the below figure and discussed in the Stamper Report, Ecology's draft SIP also found that SCR is cost effective for Erie City Boiler 1, the FCCU, regenerator unit, and the CRU #2 heater and interheaters.

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[152] Draft SIP at 161.
[153] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[154] Stamper Report at 45-48.
[155] *Id.* at 45-46.
[156] *Id.* at 46.
[157] *Id.*
[158] *Id.* at 46-47.
[159] *Id.* at 47.
[160] *Id.*
[161] *Id.* at 48
[162] Draft SIP at 185.

**Figure 6. Comparison of SCR Cost Effectiveness as Calculated by Shell to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Shell Puget Sound Refinery**[163]

| Puget Sound Refinery Emission Unit | Shell's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| Erie City Boiler 1 | $12,511/ton | $2,441/ton | 179 tpy |
| FCCU Regenerator Unit | Not Evaluated | $1,948/ton | 521 tpy |
| CRU2 Charge Heater/Interheaters | $10,813/ton | $6,346/ton | 69 tpy |

Thus, to meet the requirements of EPA's regional haze regulations, Ecology must include final determinations to require SCR in this regional haze plan for the second implementation period, these SCR installations must occur during the second implementation period and could be coordinated with maintenance outages at the Shell Puget Sound refinery.[164]

### 5. Phillips 66 Ferndale Refinery

Phillips 66 Ferndale Refinery's four-factor analysis had numerous errors, which are inconsistent with the legal requirements. As discussed in the Stamper Report, Ecology rightly corrected the errors and in so doing determined that SCR is cost effective.

Ecology calculated a Q/d value for the Phillips 66 Ferndale Refinery of 10.9.[165] NPCA data shows that the facility likely contributes to regional haze at 5 Class I areas.[166] Ecology found that the Phillips 66 Refinery had the fifth highest NOx emissions per 1,000 bpd production of all of the eighty-four refineries nationwide that it evaluated.[167]

There are numerous issues with the company's four-factor analysis because it does not comport with EPA's regulations, guidance and is based on unsupported assumptions. The Stamper Report presents details on seven issues with the company's four-factor analysis. Specifically, Shell:

[163] *Id.* at 195.
[164] Stamper Report at 49.
[165] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
[166] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[167] Draft SIP at 185.

- Erroneously used a five-year average of annual emissions for baseline emissions, contrary to EPA's regulations and guidance;[168]
- Applied an inflated interest rate, contrary to EPA's Control Cost Manual;[169]
- Used a truncated number of years for the useful life of controls;[170]
- Used high NOx emission rates with LNB, which are not supported;[171]
- Without justification assumed continual operation every hour of the year (*i.e.*, 8,760 hours per year – 100% capacity factor) in assessing reagent and other operational expenses of SCR;[172] and
- Included numerous costs that are not allowed under EPA's Control Cost Manual.[173]

As seen in the below figure, once it corrected the company's errors, Ecology found the SCR controls cost effective for the refinery.

**Figure 7. Comparison of SCR Cost Effectiveness as Calculated by Phillips 66 to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Phillips 66 Refinery[174]**

| Phillips 66 Refinery Emission Unit | Phillips 66's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| Crude Heater 1F-1 | $12,225/ton | $2,640/ton | 166 tpy |
| FCCU/CO Boiler | Not Evaluated | $3,954/ton | 247 tpy |

To meet the requirements of EPA's regional haze regulations, Ecology must include final determinations to require SCR in this regional haze plan for the second implementation period for the Phillips 66 Ferndale Refinery.

### 6. U.S. Oil & Refining Company – Tacoma Refinery

U.S. Oil & Refining Company's four-factor analysis had numerous errors, which are inconsistent with the legal requirements. As discussed in the Stamper Report, Ecology must require that the

[168] Stamper Report at 50-51..
[169] *Id.* at 51.
[170] *Id.* at 51.
[171] *Id.*
[172] *Id.* at 52.
[173] *Id.* at 52, citing P-78 to P-84.
[174] *Id.* at 52, citing Draft SIP at 192-193.

company identify and verify its assumptions. Based on additional information received from the company, Ecology must also determine whether it is necessary to include emission limitations in the SIP.

U.S. Oil & Refining (U.S. Oil) owns a refinery in Tacoma. According to Ecology, the facility has a Q/d value of 3.2.[175]

There are issues with the company's four-factor analysis. In particular, the company:

- Failed to provide baseline emissions and failed to propose enforceable SIP requirements for upcoming changes;[176]
- Applied an inflated interest rate of 7%, contrary to EPA's Control Cost Manual;[177]
- Applied a truncated useful life of controls for all units, contrary to EPA's Control Cost Manual;[178]
- Assumed NOx emission limits that are not reflective of typical limits;[179]
- Assumed an inflated retrofit factor that is not justified;[180] and
- Assumed SCR will require flue gas reheating without justification.[181]

As presented in the Stamper Report:

> As it did with the other refineries, Ecology evaluated SCR cost effectiveness using EPA's SCR cost calculation spreadsheet made available with its Control Cost Manual for the Heater H-11. Ecology found that cost effectiveness of SCR would be $15,612/ton, which was lower than U.S Oil's calculated cost effectiveness of $18,649/ton, but Ecology still found that SCR was not cost effective for this heater.[182] However, as discussed … above, U.S. Oil assumed a lower baseline for its cost analysis because it is "implementing changes during the refinery's upcoming turnaround in early 2021 that will add significantly to heat recovery, thereby reducing the fired duties of these sources."[183]

Ecology must require that U.S. Oil identify and verify the details of its cost effectiveness analysis, and Ecology must determine if it is necessary to make such changes in emissions into enforceable requirements.

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[175] Draft SIP at 162 (Table 7-1).
[176] Stamper Report at 54-55.
[177] *Id.* at 55.
[178] *Id.*
[179] *Id.* at 55-56.
[180] *Id.* at 56.
[181] *Id.*
[182] Draft SIP at 202.
[183] *Id.* at P-303.

## B. Pulp and Paper Mills

### 1. Ecology is Entirely Justified in Its Use of EPA's Control Cost Manual to Determine Cost Effective Controls for the Pulp and Paper Mills

The pulp and paper mill four-factor analyses submitted by NWPPA and by Cosmo Specialty Fibers were flawed and inconsistent with EPA's regulations and guidance. Ecology evaluated and partially adjusted the companies' cost information and provided a summary of its revised costs/ton in Appendix J of the draft regional haze SIP. Ecology's adjustments primarily included using a 3.25% interest rate for amortizing capital costs, adjusting the useful life of controls for some sources, and adjusting SNCR NOx control efficiency to 35% for some sources.[184] As discussed below, while Ecology should have made further adjustments to the control cost assessments, even with the limited changes it did make, Ecology found that controls as seen in the below figure, would be cost effective based on Ecology's reasonableness cost thresholds.[185] For the same reasons presented in the above discussion on refineries, Ecology was entirely justified in using EPA's Control Cost Manual and making the necessary corrections. And yet, Ecology's draft SIP fails to propose emission limitations based on these cost effective controls.

The $SO_2$ control cost estimates that the pulp mills submitted to Ecology are greater than the potential cost threshold range of the other RH pollutant costs of \$6,250 - \$7,800.[186]

**Figure 8. Ecology's Identification of Cost Effective Regional Haze Controls at Pulp and Paper Mills.[187]**

| Plant | Emission Unit | Control | Cost Effectiveness, \$/ton | RH Pollution Reduced, tons per year |
|---|---|---|---|---|
| Nippon Dynawave | Hog Fuel Boiler #11 | SCR | \$5,466/ton | NOx -1,025 tpy |
| Nippon Dynawave | Hog Fuel Boiler #11 | SNCR | \$5,413/ton | NOx - 500 tpy |
| Nippon Dynawave | Boiler #9 | SCR | \$6,041/ton | NOx - 175 tpy |

[184] Draft SIP, Appendix J at J-1 to J-3.
[185] Stamper Report at 58.
[186] Draft SIP at 183 and Appendix J at J-1.
[187] Stamper Report at 59, citing Draft SIP at 183 and Appendix J at J-1.

| Plant | Emission Unit | Control | Cost Effectiveness, \$/ton | RH Pollution Reduced, tons per year |
|---|---|---|---|---|
| Nippon Dynawave | Boiler #9 | LNB | \$2,754/ton | NOx - 97 tpy |
| Packaging Corp. of America (PCA) | Boiler #1 | LNB | \$5,893/ton | NOx - 26 tpy |
| PCA | Boiler #2 | LNB | \$4,834/ton | NOx - 30 tpy |
| West Rock Longview | Hog Fuel Boiler 20 | SNCR | \$6,245/ton | NOx – 115 tpy |
| WestRock Tacoma | Lime Kiln #1 | Wet ESP | \$6,964/ton | $PM_{10}$ – 33 tpy |

### 2. Ecology's Proposal to Defer Controls on Pulp and Paper Mills is Inconsistent with its Cost Effectiveness Determinations and the Legal Requirements

Based on its Q/d screening analysis, Ecology identified six pulp and paper mills and one sulfite chemical processing mill and requested that they perform four-factor analysis. Ecology correctly found the analyses from the companies fraught with errors and conducted its own cost effectiveness analyses. Ecology analyses identified cost effective controls.[188] However, based on the erroneous assumptions discussed below, Ecology assigned the pulp and paper mill source category collectively a lower priority for emission controls and its proposed SIP fails to include enforceable emission limitations.

Ecology inappropriately discounts emission controls from the pulp and paper source category assigning a lower priority. For example, Ecology suggests they "are not located as close to each other as the refineries so they do not have as great of a cumulative effect."[189] As discussed in the Stamper Report:

> While these facilities may not all be located nearby each other, these four facilities along with Cosmo Specialty Fibers, WestRock Longview, and Georgia Pacific Consumer Operations all have Q/d values that are greater than or equal to the Q/d threshold of 10 that Ecology set for selecting sources for review. Thus, the decision to defer controls on

[188] Stamper Report at 57.
[189] Draft SIP at 166.

any of these pulp and paper mills must be based on a four-factor analysis of controls, not a determination that the facilities might not have as great of a cumulative effect on regional haze as the refineries.[190]

Furthermore, Ecology's suggestion that the potential reduction in regional haze emissions from pulp and paper mills is "vastly less than the potential refinery emission reductions"[191] provides a justification to discount control is also misplaced. Ecology's proposed reliance on visibility to reject emission controls is outside of the four-factor analysis.[192] As explained in the Stamper Report:

> [T]he McKinley Paper Company (for which Ecology inexplicably did not conduct a four-factor analysis of controls) has the second highest Q/d value (83.1) of any facility for which Ecology requested four-factor analyses.[193] Three other pulp and paper mills are in the top ten highest Q/d values as calculated by Ecology – the WestRock Tacoma facility, the Nippon Dynawave Packaging Company in Longview, and the Pt Townshend Paper Corporation.[194, 195]

Contrary to the Act and regional haze regulations, Ecology proposes to defer and address this source sector in the next planning period. Ecology must propose and establish enforceable emission limits in its SIP for the pulp and paper sources.

### 3. Ecology Must Conduct the Required Four-Factor Analysis for the McKinley Paper Plant

As explained in the Stamper Report: it appears that Ecology neither requested nor conducted a four-factor analysis for the McKinley Paper Plant, which is a pulp and paper plant with a Q/d value of 83.1, and has the second highest Q/d value of all facilities evaluated by Ecology.[196] It's important to note that the Technical Support Document for the current operating permit for the McKinley Plant states that the McKinley facility was purchased from Nippon Paper Industries USA Co. in 2017.[197] Therefore is a *different* source than Nippon Dynawave, which is located in Longview, Washington.

Ecology must conduct a four-factor analysis of controls for the McKinley Paper Plant, as it greatly exceeded Ecology's Q/d threshold of 10 and as indicated by the analysis, require emission controls.

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190 Stamper Report at 57-58.
191 Draft SIP at 167.
192 Stamper Report at 58.
193 *Id.* at 7, 57.
194 Stamper Report at 57, citing Draft SIP at 160-161.
195 *Id.*
196 Stamper Report at 57.
197 Stamper Report at 7, citing,
https://www.orcaa.org/wpcontent/uploads/TSD_McKinley_Final_17August2021.pdf.

4. **Deficiencies that Appear in All of the NWPPA Pulp and Paper Mill Four-Factor Analyses**

The Stamper Report discusses deficiencies in the control evaluations and cost-effectiveness analyses that apply to all of the NWPPA four-factor analyses, which include:

- Use of an inflated interest rate, inconsistent with EPA's Control Cost Manual;[198]
- Assumed too short of a life of pollution controls in amortizing capital costs of controls, inconsistent with EPA's Control Cost Manual;[199]
- Apparent use of a cost per ton threshold ($3,400/ton) that is neither justified nor supported by the facts in its analysis;[200]
- Use of an outdated report from 2013 to derive costs for certain controls to scale costs, which is discouraged by EPA's Control Cost Manual;[201]
- Inappropriately, included costs for sales taxes, property taxes and insurance in its capital costs of controls for several controls evaluated;[202] and
- Suggested fuel switching was too costly without providing sufficient details for its assumptions.[203]

Ecology must correct all these errors in the NWPPA four-factor analyses and redo the cost-effectiveness calculations. Once Ecology makes corrections, eliminates the errors, and makes the other necessary corrections, the various would likely be even more cost effective for the emitting units at the pulp and paper sources.

5. **$SO_2$ Controls for the WestRock Lime Kiln**

Ecology must fully evaluate NWPPA's unsupported assertions regarding $SO_2$ controls for the lime kilns. For example, NWPPA asserts that $SO_2$ emissions from all the lime kilns are low, suggesting that installing additional $SO_2$ controls would not be cost effective.[204] EPA stated in a 2014 document that nearly 70% of lime kilns in the pulp and paper industry are equipped with wet scrubbers.[205] NWPPA evaluated one of the lime kilns in Washington that is not equipped with a wet scrubber - the WestRock Longview Mill Lime Kiln 5, but NWPPA states that "additional [$SO_2$] control technology is not evaluated due to the low emissions achieved with the current control technology."[206] The WestRock Longview Kiln 5 is the only lime kiln evaluated by NWPPA that does not have a scrubber for $SO_2$ control out of the seven lime kilns using

[198] *Id.* at 63.
[199] *Id.* at 63-64.
[200] *Id.* at 64-65.
[201] *Id.* at 65.
[202] *Id.* at 66.
[203] *Id.*
[204] Draft SIP, Appendix O at O-23.
[205] U.S. EPA, Universal Industrial Sectors Integrated Solutions Model for Pulp and Paper Manufacturing Industry – Universal ISIS-PNP, November 2014, at 2-40, https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=311359.
[206] Draft SIP, Appendix O at 2-5.

similar fuels (fuel oil and natural gas) that were evaluated by NWPPA.[207] Given that most lime kilns are equipped with wet scrubbers (both nationally and in Washington state), Ecology should evaluate adding a wet scrubber to this lime kiln for $SO_2$ control and also PM control.[208]

### 6. NWPPA's NOx Controls Evaluations for Power Boilers

NWPPA's cost effective analysis for several of the power boilers at the six pulp and paper mills was unreasonable and inconsistent with EPA's regulations and guidance. The Stamper Report presents details on five issues with the NWPPA's cost effective analysis. In particular, the NWPPA:

- Failed to justify assuming one level of NOx control for all the power boilers evaluated, regardless of the NOx inlet rate to the SNCR system.[209]
- Greatly underestimated the NOx reduction capabilities and cost effectiveness of SNCR by only assuming 35% NOx control.[210] In contrast to EPA's Control Cost Manual that indicates "NOx removal efficiencies for SNCR used at boilers in the pulp and paper industry as achieving a median NOx removal efficiency of 50% with urea used as the reagent with a range of 20-62%."[211] And EPA's statement " that median NOx reductions with ammonia-based SNCR systems are 61-65% and that most boilers with ammonia-based SNCR systems that are solid fuel-fired are fired with wood or municipal solid waste."[212]
- Failed to justify inflating the retrofit factor provided in EPA's SCR cost calculation spreadsheet. NWPPA applied a retrofit factor of 1.5 to all boilers, rather than using EPA's 20% retrofit factor.[213]
- Failed to provide supporting data necessary on various assumptions, including the following: "baseline NOx emissions and emission rates of each boiler in tons per year and lb/MMBtu;"[214] "operating hours and/or operating capacity factor of each power boiler used in estimating the operational expenses of these controls;"[215] "specific costs assumed for the SNCR and SCR reagent (including what type of reagent was assumed) or the electricity costs;"[216] and "what unit characteristics and fuel characteristics were assumed in the cost spreadsheets for each boiler."[217]
- Applied a high interest rate of 7%, which is inconsistent with EPA's Control Cost Manual.[218]

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[207] *Id.* at 1-3.
[208] Stamper Report at 67.
[209] *Id.* at 67-68.
[210] *Id.* at 68.
[211] *Id.* at 68, citing EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-2, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[212] *Id.*, citing EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-1, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[213] *Id.* at 68-69.
[214] *Id.* at 69.
[215] *Id.* at 69.
[216] *Id.* at 69.
[217] *Id.* at 69.
[218] *Id.* at 69-70.

- Applied a truncated life for LNBs of only 10 years, which is inconsistent with EPA's evaluations that assume lifetimes of 30 years.[219]
- Assumed an unreasonably low NOx reduction rate for LNB of 50% and failed to evaluate flue gas recirculation (FGR) in combination with LNB. In contrast, EPA states that these controls are normally used together to reduce NOx, and emission reductions of 60 to 90% are achievable.[220]

Additionally, based on the back-calculations for NOx emission reductions for SNCR and SCR, the Stamper Report explains that NWPPA's cost effectiveness calculations seem inconsistent with the baseline emissions assumed for the boilers evaluated for LNB control.[221] However, because NWPPA failed to provide the entire spreadsheets for its cost calculations, neither the public nor Ecology can review to ensure consistency and accuracy.[222]

Merely "revising the annualized capital costs of LNBs using NWPPA's cost numbers but using a capital recovery factor reflective of a 3.25% interest rate and a 25-year life makes a significant difference in the cost effectiveness of LNBs at the power boilers," as was done in the Stamper Report and shown in the below figure.[223]

**Figure 9. Revisions to NWPAA's Cost Effectiveness of LNBs at Power Boilers to Use a Lower Interest Rate and a More Realistic Life of LNB Controls (3.25% Interest Rate, 25-Year Life of LNB)**

| Plant-Unit | Total Annualized Costs (at 3.25% Interest and 25 Year Life) | NOx reductions (per NWPPA), tpy | Revised Cost Effectiveness (at 3.25% Interest Rate and 25-Year Life) | NWPPA's Cost Effectiveness (at 7% Interest Rate and 10-Year Life) |
|---|---|---|---|---|
| Nippon Dynawave Boiler 6 | $141,708 | 18.55 | $7,639 | $12,093 |

[219] *Id.* at 70, citing EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natural gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).
[220] *Id.* at 70, citing EPA, AP-42 Emission Factor Documentations, Section 1.4 Natural Gas Combustion, at Section 1.4.4, https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.
[221] *Id.* at 70.
[222] *Id.*
[223] *Id.*

| Plant-Unit | Total Annualized Costs (at 3.25% Interest and 25 Year Life) | NOx reductions (per NWPPA), tpy | Revised Cost Effectiveness (at 3.25% Interest Rate and 25-Year Life) | NWPPA's Cost Effectiveness (at 7% Interest Rate and 10-Year Life) |
|---|---|---|---|---|
| Nippon Dynawave Boiler 7 | $168,795 | 28 | $6,028 | $9,543 |
| Nippon Dynawave Boiler 9 | $250,813 | 97.3 | $2,578 | $4,081 |
| PCA Wallula Boiler 1 | $142,579 | 25.85 | $5,516 | $8,732 |
| PCA Wallula Boiler 2 | $136,856 | 30.3 | $4,517 | $7,162 |

In light of the above deficiencies, Ecology must make the following corrections to NWPPA's analysis and its draft SIP:

- Consider SNCR to achieve at least 50% NOx control at power boilers used in the pulp and paper industry if urea is the reagent;[224]
- Not allow use of any retrofit factor greater than 1 for SNCR costs at any of the power boilers without sufficient documentation from NWPPA or the facility owners to justify the use of a retrofit factor;[225]
- Not allow use of retrofit factors greater than 1 in the SCR cost analyses unless justified based on the specific situation for a particular power boiler;[226]
- Ask NWPPA to make all of the pages of the SNCR and SCR spreadsheets available for review for the power boilers so that this information can be evaluated by Ecology and the public;[227]
- Ensure that NWPPA evaluates the most effective combustion controls for the power boilers, and perform the evaluation if NWPPA fails to do so;[228]

[224] *Id.* at 68.
[225] *Id.* at 68.
[226] *Id.* at 68-69
[227] *Id.* 69.
[228] *Id.* at 70.

- Correct the unjustified high interest rate and truncated useful life assumptions;[229] and
- Review the cost inputs used in the SCR cost analyses - it is imperative to ensure that costs for items such as reagent, electricity, or catalysts to ensure they are supported and were not overstated in those analyses.[230]

Once Ecology makes the NOx reduction corrections, eliminates the improper retrofit factor, and the other necessary corrections are made, the SNCR and SCR controls would likely be even more cost effective for the power boilers at the pulp and paper mills.

### 7. Four-Factor Analyses for the Cosmo Specialty Fibers Mill

Cosmo Specialty Fibers (Cosmo) operates a sulfite pulp mill located in Cosmopolis, Washington. A four-factor analysis was submitted for controls at only one emissions unit at the plant: the hog fuel boiler at the facility.[231] Notably, Cosmo neither provided four-factor analyses for the recovery boilers at the facility (Recovery Boiler 1, 2, and 3), nor provided four-factor analyses for the hogged fuel dryer at the facility. Instead, Cosmo erroneously relied on Ecology's 2016 analysis entitled "Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills" dated November 2016 to justify no additional regional haze controls for its recovery boilers.[232] As explained in the Stamper Report, there are numerous issues with reliance on that report, including: the November 2016 Ecology State-RACT analyses were focused on whether the visibility benefits of pollution controls evaluated justified the costs of the pollution controls.[233]

The visibility benefits of controls - which are part of State-RACT - are not part of the Clean Air Act's four-factor analysis. Ecology's 2016 analysis fails to comply with the Act's requirements and Cosmo's reliance on Ecology's analysis in attempts to avoid the four-factor analysis is misplaced.[234] Furthermore, contrary to EPA's guidance and rules to use the most recent emission inventories, Ecology's State-RACT analysis relied on emission inventories between 2003 to 2011, and during three of those years the source was not operating.[235] Furthermore, when the mill restarted in 2011, it had eliminated two processes and the production at the mill varies upon market demand.[236] Thus, Ecology's use of outdated data in its 2016 State-RACT report was not reflective of new and current operations at the source.

Cosmo evaluated SCR and SNCR for NOx controls at the hog fuel boiler and evaluated use of an ESP to reduce PM emissions from the hog fuel boiler. Based on unsupported and erroneous assumptions, Cosmo determined that no additional controls are required at the hog fuel boiler to address regional haze requirements.[237] The Stamper Report identifies seven issues with the company's cost effectiveness analyses for the hog fuel boiler:

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[229] *Id.*
[230] *Id.* at 71.
[231] Draft SIP, Appendix O at O-278 to O-312 (December 2019 Four-Factor Analysis for Cosmo Specialty Fibers).
[232] *Id.* at O-288.
[233] Stamper Report at 72.
[234] *Id.*
[235] *Id.*
[236] *Id.* .
[237] *Id.* at 72, citing Draft SIP, Appendix O at O-285.

- Used an inflated interest rate of 4.75% that is inconsistent with EPA's Control Cost Manual and current prime rate of 3.25%;[238]
- Assumed of too short of a life of pollution controls of 20 years in amortizing capital costs of controls, when a 25-30 year life is likely a more appropriate life of controls to use in amortizing capital costs of a pollution control for the hog fuel boiler;[239]
- Assumed, without justification 25% NOx control for the hog fuel boiler;[240]
- Assumed, without justification and detailed calculations, that the flue gas would need reheating for SCR, which reflects 85 to 88% of Cosmo's total annual cost of SCR;[241]
- Erroneously eliminated evaluation of the cost effectiveness of a high dust SCR system, which would eliminate any need for flue gas reheating, thus reducing Cosmo's annual cost estimates of SCR significantly;[242]
- Failed to evaluate the cost effectiveness of a high dust SCR system, which would eliminate any need for flue gas reheating, thus reducing Cosmo's annual cost estimates of SCR significantly;[243] and
- Erroneously included costs for taxes and insurance for the ESP for the hog fuel boiler.[244]

In correcting and finalizing its SIP, Ecology must look to examples of similar emission units in the pulp and paper industry in Washington that have installed NOx and PM controls, which provide relevant examples of a source determining it was cost-effective to install the pollution controls. As discussed in the Stamper Report, these examples include controls at the PCA Wallula Mill and WestRock Longview Power Boiler.[245]

Ecology must: make the corrections presented above that are necessary for the SCR/SNCR cost effectiveness calculations to control NOx and PM emission from the hog fuel boiler; and ensure that the required four-factor analyses are prepared and emission controls evaluated and SIP emission limitations adopted for the recovery boilers at the facility (Recovery Boiler 1, 2, and 3), and the hogged fuel dryer at the source.

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[238] *Id.* at 72-73.
[239] *Id.* at 73.
[240] *Id.* at 73.
[241] *Id.* at 74, citing Draft SIP, Appendix O at O-295.
[242] As explained in the Stamper Report, Cosmo's justification for not evaluating a high dust SCR was alleged and unsupported concerns about particulate emissions poisoning the SCR catalyst. Draft SIP, Appendix O at O-295. As the Stamper Report explains, there are several options to reduce or slow down catalyst deactivation that should have been considered. *Id.* at 74.
[243] *Id.* at 74.
[244] *Id.* at 74.
[245] *Id.* at 74-75.

## VI. Ecology Should Evaluate and Require Controls at the Ardagh Glass Plant

One additional facility that Ecology should evaluate for regional haze controls is the Ardagh Glass plant in Seattle, Washington. According to NPCA analysis, the facility likely affects regional haze in 2 Class I areas.[246] NPCA previously submitted to Ecology a four-factor analysis of reasonable progress controls for the Ardagh Glass Plant with its February 16, 2021 comment letter to Ecology for the informal comment period,[247] but Ecology has not responded to those comments in the public review draft regional haze plan for the second implementation period.

The largest sources of emissions at a glass plant are the fossil fuel-fired furnaces which melt glass. At the Ardagh plant, there are five furnaces. No. 1 is an all-electric furnace; No. 2, No. 3 and No. 5 furnaces are oxy-fuel fired; and No. 4 is an end-port regenerative furnace.

At the request of NPCA, Steve Klafka of Wingra Engineering, evaluated reasonable progress control options where he focused on the use of ceramic catalytic filtration systems at Furnaces 2, 3, 4, and 5 of the Ardagh Glass Plant.[248] The Klafka Report discusses how ceramic catalytic filtration systems have been used at existing glass plants as a highly effective multi-pollutant control technology.[249] The Klafka Report included a cost analysis for ceramic catalytic filtration systems at the Ardagh Glass Plant furnaces to reduce NOx and also $SO_2$ and $PM_{10}$. As summarized in the Stamper Report, the Klafka Report concluded that it is technically feasible to add a catalytic ceramic filtration system to the glass furnaces at Ardagh Glass and that it would be very cost effective to do so, at a cost per total tons of pollutant removed of $4,766/ton based on emission reductions from 2014 actual emissions and at a cost of $2,238/ton based on emission reductions from potential emissions.[250]

Thus, a ceramic catalytic filtration system is a very cost effective control that can significantly reduce emissions from the Ardagh Glass Plant, and Ecology should strongly consider this control and the emission reductions at Ardagh Glass as part of its regional haze control strategy.

## VII. Ecology's Must Provide a Basis for and Apply a Consistent Cost Effectiveness Threshold

EPA's regional haze guidance and regulations require that the State Implementation Plan (SIP) "explain why the selected threshold is appropriate for that purpose and consistent with the requirements to make reasonable progress."[251] Of significant concern to commenters is that

[246] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[247] *See* NPCA, Comments Submitted for Informal comment period: Regional Haze SIP Revision - 2nd 10-Year Plan (Feb. 16, 2021), at 11.
[248] Klafka Report.
[249] *Id.* at 9.
[250] *Id.* at 12. Note that the narrative discussion of the Klafka report indicates lower cost effectiveness numbers of $3,768/ton for reductions from 2014 emissions and $1,819/ton from reductions in potential emissions, but Table 5 of the report indicates a higher cost per ton of pollutants removed. The Table 5 data of the Klafka Report is included in Table 12 of the Stamper Report as the data are assumed to be the more accurate numbers.
[251] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 39.

Ecology's draft SIP lacks the justification for its cost reasonableness threshold.[252] Ecology arbitrarily applied inconsistent cost thresholds, which it must not do.[253] For example in its four-factor review for the pulp and paper sources, Ecology indicates that:

- For NOx control using a low-NOx burner, the following units have estimated cost/ton value less than the potential reasonableness threshold of $6,300/ton.[254]
- For NOx control using an SCR or SNCR, the following units have a cost/ton value less than the potential reasonableness threshold of $6,250/ton.[255]
- For $PM_{10}$ control, the following units have a cost/ton value less than the potential reasonableness threshold of $7,800/ton.[256]
- The $SO_2$ control cost estimates that the pulp mills submitted to Ecology are greater than the potential cost threshold range of the other RH pollutant costs of $6,250 - $7,800.[257]

Additionally, while not stated so explicitly in its proposed SIP, Ecology does collectively find the costs for all its revised cost effectiveness analyses reasonable (Figures 3 through 9 above), which include a wide range of costs per ton.

The Stamper Report contains an extensive cost effectiveness survey and highlights from various states. Additionally, the State of Colorado recently indicated that it "is using $10,000 per ton of regional haze pollutant as the nominal cost threshold to determine cost effective control strategies for Round 2 RP."[258]

As explained in EPA's Guidance, Ecology must provide a basis for and establish the cost effectiveness threshold upon which the State bases its decision, including an explanation of why the cost effectiveness threshold is appropriate and consistent with the requirement to make reasonable progress.[259]

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[252] Stamper Report at 59
[253] *Id.* at 59.
[254] Draft SIP at 182.
[255] *Id.* at 183.
[256] *Id.*
[257] *Id.*
[258] "Prehearing Statement of the Colorado Department of Public Health and Environmental, Air Pollution Control Division," *In the Matter of Proposed Revisions to Regulation No 23* (Oct. 7, 2021) at 7, (further explaining that "[t]his threshold is applied to the individual pollutants in the control strategy analyses, specifically NOx, PM, and SO2. This threshold value is an increase from Round 1 and reflects the fact that with each successive round of planning, less costly and easier to implement strategies have already been adopted. Colorado has maintained this threshold throughout the planning process despite the fact that each of the Class I areas in Colorado is below the URP for 2028.") (Enclosure 8)
[259] *Supra* note 251.

## VIII. Comments on Ecology's Long-Term Strategy for Visibility Impairment

### A. Ecology Must First Conduct the Required Four-Factor Analysis and Then Develop the Reasonable Progress Goals

Ecology's draft long-term strategy uses reasonable progress goals developed by the Western Regional Air Partnership (WRAP) *before* conducting the required four-factor analysis – it has impermissibly reversed the order of the requirements. The RPGs are not to be developed before the four-factor analyses but as a result of the four-factor analyses.[260] Ecology's draft long-term strategy states that it "relied on the Western Regional Air Partnership (WRAP) for air quality modeling and other analytical tools to identify pollutants, the sources of those pollutants, and to predict future levels of visibility impairment."[261] Ecology also states "[t]hrough WRAP technical collaborations, the western states agreed upon the [reasonable progress goals (RPGs)] set for 2028 and a regionally consistent approach to addressing visibility impairment in the West."[262] Ecology must first conduct the four-factor analyses, determine measures for reducing visibility impairing emissions based on the Act's four-factor analysis and then use the results to develop proposed revisions to the reasonable progress goals.

### B. Ecology Must Not Revise Its Current SIP and Violate the Clean Air Act's Anti-Backsliding Provision

Section 110(l) of the Clean Air Act prohibits EPA from approving an implementation plan revision if the revision would "interfere with any applicable requirement concerning attainment and reasonable further progress … or any other applicable requirement of this chapter."[263] This provision is designed to ensure that air-quality improvements are not reversed through regulatory actions to weaken pollution limits. This anti-backsliding provision applies to existing BART determinations, including provisions specific to the Centralia plant, as the Act's "applicable requirement[s]" include the regional haze program's BART requirements.[264] Indeed, Courts have routinely upheld EPA interpretations of Section 110(l) as preventing implementation plan revisions that would increase overall air pollution limits or worsen air quality.[265] Should Ecology must either remove or provide an adequate demonstration under Section 110(l) of the Clean Air Act.

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[260] *See, e.g.*, 82 Fed. Reg. 3090-91 (Jan. 10, 2017).
[261] Draft SIP at 206.
[262] *Id.* at 208.
[263] 42 U.S.C. § 7410(l); *see also El Comite Para El Bienestar de Earlimart v. EPA*, 786 F.3d 688, 692 (9th Cir. 2015).
[264] *See Oklahoma v. EPA*., 723 F.3d 1201, 1204, 1207 (10th Cir. 2013).
[265] *See WildEarth Guardians v. EPA*, 759 F.3d 1064, 1074 (9th Cir. 2014) (a haze plan that "weakens or removes any pollution controls" would violate section 110(l)); *see also Indiana v. EPA*, 796 F.3d 803, 812 (7th Cir. 2015) (noting that EPA allows "emissions-increasing SIP revisions" if a state "identif[ies] substitute emissions reductions such that net emissions are not increasing."); A*la. Envtl. Council v. EPA*, 711 F.3d 1277, 1293 (11th Cir. 2013) (Section 110(l) "permit[s] approval of [a] SIP revision 'unless the agency finds it will make air quality worse'" or increase emissions) (quotation and citation omitted); *Kentucky Resources Council v. EPA*, 467 F.3d 986, 995 (6th Cir. 2006) (Section 110(l) allows the agency to approve a plan revision that weakened some existing control measures while strengthening others, but only "[a]s long as actual emissions in the air are not increased" and "air quality [is not] worse[ned]").

## C. The Public was not Provided an Opportunity Review and Comment on the WRAP's Emission Inventories and Modeling

While the Western states may have agreed on the modeling (and presumably the emission inventory development) compiled or completed by the WRAP, the general public has not had the opportunity to review and comment on the assumptions that went into the emission inventories or the modeling. The regional haze regulations require the long term strategy to "document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects."[266] The issue here is that Ecology has not documented and incorporated the underlying RPO information in the draft SIP for the public to review and provide comments. As part of its proposed SIP revisions, Ecology must not only follow the requirements in the RHR, but also the requirements for preparation, adoption and submittal of SIPs (*i.e*., 40 C.F.R. §§ 51.100, 51.102, 51.103, 51.104, 51.105 and Appendix V to Part 51. Ecology has an obligation to make transparent and cite to (and provide weblinks to) the technical support documentation it proposes to rely on and use as part of its SIP revision (*e.g*., such regional planning organization technical analyses) and provide the public with the opportunity to comment on such analyses. Thus, Ecology must cite to and provide weblinks to the WRAP's documentation and analysis for the emissions information, monitoring and modeling.[267]

The RHR requires that "[t]he State must identify the baseline emissions inventory on which its strategies are based."[268] Except for the facilities for which it conducted four-factor analyses, Ecology has not provided its baseline emission inventory of all visibility-impairing pollution from the various sources within its state. Ecology must provide that information with the long-term strategy for public review and comment. Washington's long-term strategy relies on emission reductions associated with the following: federal, state, and local rules regarding mobile onroad engines, nonroad engines, marine engines, fuel sulfur limitations, petroleum

[266] 40 C.F.R. § 51.308(d)(3)(iii).

[267] 40 C.F.R. Part 51, Appendix V ¶ 2.2 Technical Support. "(a) Identification of all regulated pollutants affected by the plan. (b) Identification of the locations of affected sources including the EPA attainment/nonattainment designation of the locations and the status of the attainment plan for the affected areas(s). (c) Quantification of the changes in plan allowable emissions from the affected sources; estimates of changes in current actual emissions from affected sources or, where appropriate, quantification of changes in actual emissions from affected sources through calculations of the differences between certain baseline levels and allowable emissions anticipated as a result of the revision. (d) The State's demonstration that the national ambient air quality standards, prevention of significant deterioration increments, reasonable further progress demonstration, and visibility, as applicable, are protected if the plan is approved and implemented. …. (e) Modeling information required to support the proposed revision, including input data, output data, models used, justification of model selections, ambient monitoring data used, meteorological data used, justification for use of offsite data (where used), modes of models used, assumptions, and other information relevant to the determination of adequacy of the modeling analysis. (f) Evidence, where necessary, that emission limitations are based on continuous emission reduction technology. (g) Evidence that the plan contains emission limitations, work practice standards and recordkeeping/reporting requirements, where necessary, to ensure emission levels. (h) Compliance/enforcement strategies, including how compliance will be determined in practice. (i) Special economic and technological justifications required by any applicable EPA policies, or an explanation of why such justifications are not necessary."

[268] *Id.*

refinery maximum achievable control technology (MACT), boiler MACT, revised utility boiler MACT, various area source MACT, industrial/commercial boiler burning designated solid wastes NSPS, sewage sludge incinerator NSPS, ozone and $PM_{10}$ SIPs, state oil and gas emission control programs, the 2010 $SO_2$ and $NO_2$ NAAQS, the 2013 $PM_{2.5}$ NAAQS, and the 2015 ozone NAAQS.[269] To enable the public to evaluate these emission reductions, Ecology must provide a baseline emissions inventory for these various source categories.

### D. Ecology Must Document the Technical Basis for Nonroad Engine Reductions

In its discussion of state, federal and local rules and controls that limit visibility-impairing pollutants, Ecology states "[f]ederal fuel and engine rules for on-road and nonroad engines are of special importance. These result in large projected percent decreases in visibility-impairing emissions in Washington by 2028."[270] Ecology must identify the specific assumed reductions in emissions from nonroad engines and must document the technical basis for the assumed emission reductions in nonroad engines, as required by 40 C.F.R. § 51.308(d)(3)(iii). The nonroad engine requirements in 40 C.F.R. Parts 89 and 1039 require manufacturers to only make engines meeting certain specified emission standards with the most stringent Tier 4 emission standards applying in approximately 2014 and beyond. However, the federal rules do not require companies to use these cleaner burning engines. It is not clear whether Washington State or local rules require companies to replace existing engines with these cleaner burning engines.

Similarly, while ultra-low sulfur diesel fuel has been available since about 2006 and has been required by diesel manufacturers since 2014, there are exemptions for older locomotive and marine engines.[271] Thus, Ecology should provide the technical basis for assumed emission reductions from nonroad engines in Washington state, both due to use of lower-emitting engines and use of lower sulfur fuel. To the extent the assumptions regarding emission reductions from nonroad engines were developed by the WRAP, Ecology should document the WRAP's assumptions and provide links to the underlying documentation and provide the public the opportunity to review and comment on it. Finally, because Ecology is relying on federal rules for future emission projections, Ecology must also document its assumptions, provide citations to the federal rules it relies on, and include enforceable measures in proposed SIP revision.

### E. Permit Actions Are Not an Off-Ramp to the Four-Factor Analysis Requirement

As explained in the Stamper Report, Ecology inappropriately excluded sources from the four-factor analysis in light of pending permit actions:

> [T]here were a few sources for which Ecology did not request a four-factor analysis of controls for, because "[s]ome of these facilities had existing legal requirements or pending permit actions to reduce emissions."[272] Those facilities were the TransAlta Centralia power plant, the Cardinal FG Winlock glass plant, and the Ash Grove Cement

[269] Draft SIP at 209.
[270] *Id.* at 6.
[271] *See* https://www.epa.gov/diesel-fuel-standards/diesel-fuel-standards-and-rulemakings.
[272] Draft SIP at 163.

Plant.[273] Ecology also will only request a four-factor analysis of controls for the Intalco Aluminum Plant and the Alcoa Wenatchee Aluminum Plant if the plants restart operations.[274, 275]

Moreover, a RACT analysis that Ecology may have gone through (or will go through in the future) for an individual source or source category is separate and distinct from the four-factor reasonable progress analysis requirement. The regional haze program includes identifying and issuing requirements to remedy *existing* impairment and also requirements necessary to prevent *future* impairment. As discussed below in Section III, the four-factor RP and five-factor RACT analyses apply different factors and consider different information because they are different programs with different objectives. A RACT analysis and controls must not be used as an offramp – or in place of – the requirement to conduct the four-factor RP analysis and determine RP for the source. The regional haze four-factor RP analysis and determination applies *in conjunction with* other CAA programs. Therefore, as individual sources and source categories are modified and subject to emission controls (*e.g.*, RACT), Ecology must take into consideration *all* requirements of the CAA (*e.g.*, RP four-factor analysis and determination) and not make one decision in isolation, set aside distinct requirements or delay their implementation. A state's issuance of a permit does not replace its responsibility under the CAA to conduct the required RP four-factor analysis.

### F. Ecology Must Document the Extent to Which Emission Reductions Have Occurred in Other Programs

Ecology identifies several control strategies that were not in the previous Regional Haze SIP that apply at the Federal and/or State level. Ecology states that the most current emission inventory reflects several of these rules, including the following:[276]

- MARPOL VI,
- The North American Emission Control Area (ECA) for marine vessels, and
- The marine engine requirements in 40 CFR Part 94.

Ecology should document the extent to which emission reductions have actually occurred as a result of these regulations and requirements. For example, for the sulfur standard for marine vessels, Ecology acknowledges that EPA and the U.S. Coast Guard have allowed some shipping companies delayed compliance dates with these requirements.[277] Ecology should document the extent to which shipping companies doing business in Washington state are complying with these standards or whether such companies have been granted a delay in compliance and, if so, how long compliance has been delayed. It appears that the MARPOL Annex VI requirements are applicable to marine engine manufacturers pursuant to 40 C.F.R. Part 90, but the requirements do not require that shipping companies use those engines. Further, the EPA recently issued

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[273] *Id.* at 212.
[274] *Id.* at 178, 180-181.
[275] Stamper Report at 6-7
[276] Draft SIP at 211.
[277] *Id.*

regulations on marine engines that would weaken emission standards and sulfur in fuel standards.[278] Thus, we request that Ecology identify the extent to which the lower-emitting engines are being utilized by shipping companies doing business in Washington state. Ecology states that "[t]he effects of the marine vessel fuel sulfur requirements are reflected in the IMPROVE data, though the effect of the [North American Emissions Control Area (ECA)] are not fully reflected in the data due to the long lead time for the MARPOL requirements and the relatively recent date (2013) for vessels to meet the first stage requirements."[279] We request that Ecology also document the extent to which emission reductions associated with these programs have been reflected in the emissions inventories modeled by the WRAP and the extent to which any such modeled emission reductions were ground-truthed. Finally, if Ecology is relying on federal rules for future emission projections, Ecology must also document its assumptions, provide citations to the federal rules it relies on, and if enforceable measures are necessary, include them in the proposed SIP revision.

With respect to mobile sources, Ecology states that Washington's vehicle emissions testing program was phased out by the legislature "based on Ecology's prediction that more fuel efficient and electric vehicles would replace the need for it by 2020…."[280] Ecology also discusses the Washington legislature's adoption of California vehicle emission standards for passenger cars, light duty trucks and medium duty passenger vehicles. Ecology stated that it is currently in the process of adopting rules reflective of the state's legislative authority.[281] Ecology should provide a timeline for when that process is projected to be complete and when new vehicle emission standards will be phased in.

### G. Ecology Must Include Details and the Practically Enforceable Emission Limitations and Timeframes for the NAAQS Requirements

For the emission reductions due to NAAQS revisions since 2007, the state identified the 2010 NOx NAAQS, the 2010 $SO_2$ NAAS, the 2013 $PM_{2.5}$ NAAQS, and the 2015 ozone NAAQS. Ecology should identify rules/emission standards and requirements that it has adopted to require emission reductions to comply with these NAAQS and when compliance was or will be required. Ecology should also make clear whether any area in Washington state has been or will be designated as nonattainment for any of these NAAQS and whether additional NAAQS control requirements will be forthcoming in the state. The long-term strategy is supposed to detail the enforceable emission limitations and compliance timeframes.[282] Thus, Ecology's plan must include more details on the NAAQS requirements that it relies on for future emissions controls.

### H. Ecology's Reliance on Existing Programs is Misplaced

Ecology exclusive reliance on the continued implementation of various air quality rules and programs to ensure reasonable progress is misplaced.[283] While the RHR allows for

[278] *See* 85 Fed. Reg. 62,218 (Oct. 2, 2020); 84 Fed. Reg. 69,335 (Dec. 18, 2019).
[279] Draft SIP at 211.
[280] *Id.* at 214.
[281] *Id.*
[282] 40 C.F.R. § 51.308(d)(3).
[283] *See, e.g.*, Draft SIP at 231.

consideration of the non-visibility air quality rules and program requirements and accounting for reductions that come from outside the program, the issues with the draft SIP are that there are no additive reductions and the alleged reductions that come from outside the regional haze program are unenforceable. Furthermore, as discussed above and in the attached Stamper and Kafka Reports, there are cost-effective pollution control measures that are readily achievable for many of Washington's sources. In fact, several of the sources are already capable of achieving on a continuous basis better emission rates than they are currently displaying.

Additionally, reasonable progress requires that states consider the four statutory factors and adopt and include in their SIPs enforceable emission limitations to achieve reasonable progress toward the elimination of all anthropogenic pollution in Class I areas. This means that states must secure meaningful emission reductions that build on progress already achieved and requirements already underway. There is an expectation that reductions are additive to ongoing and upcoming reductions under other CAA programs. Indeed, as EPA's July 2021 Memo makes clear:

> [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.[284]

## I. Ecology's Reliance on the "Glide Path" Violates the Clean Air Act and Regional Haze Rule

Ecology attempts to justify deferring any further emission reductions for every major source in the state by pointing out that Class I areas appear to be trending below these area's glide path or URP, which it suggests is sufficient to achieve reasonable progress.[285] EPA has made clear, however, that meeting or exceeding the URP does *no*t obviate the need for states to conduct a robust analysis and making a technical demonstration that additional controls or emission reductions are not reasonable. "[A]n evaluation of the four statutory factors is required . . . regardless of the Class I area's position on the glidepath . . . . the URP does not establish a 'safe harbor' for the state in setting its progress goals."[286] Rather, states must "determine what

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[284] EPA July 2021 Memo at 13.

[285] *See, e.g.*, Draft SIP at 41-42.

[286] 81 Fed. Reg. 66,331, 66,631 (Sept. 27, 2016); *see also* 81 Fed. Reg. 296, 326 (Jan. 5, 2016) (determining, as part of the reasonable progress federal implementation plan for Texas, "the uniform rate of progress is not a 'safe harbor' under the Regional Haze Rule."); EPA, Responses to Comments at 120, Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan: Best Available Retrofit Technology and Interstate Transport Provisions, EPA Docket No. EPA-R06-OAR-2016-6011 (June 2020) ("EPA has repeatedly and consistently taken the position that meeting a specific reasonable progress goal is not, itself, a "safe harbor," and does not relieve the state of the obligation to consider additional measures for reasonable progress. If it is reasonable to make more progress than the URP, a state must do so, as EPA explained in the 1999 Regional Haze Rule) (citing 64 Fed. Reg. at 35732); *see also* 81 Fed. Reg. at 66,370 ("EPA's longstanding interpretation of the Regional Haze Rule is that 'the URP does not establish a 'safe harbor' for the state in setting its progress goals.") (quoting 79 Fed. Reg. 74818, 74834)).

emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors" and must not reject "control measures determined to be reasonable" based on the degree of progress.[287]

Indeed, in its July 8, 2021 Memo, EPA reiterated that the uniform rate of progress is "not a safe harbor," and that it is not appropriate to reject cost-effective emission reductions on the basis that visibility in a particular Class I area is on the glide path. Instead, states are required to "evaluate and determine emission reduction measures that are necessary to make reasonable progress *by considering the four statutory factors*."[288] Here, Ecology's decision to defer reasonable and cost-effective controls to another planning period, simply because Class I areas are on the glidepath, is contrary to the Clean Air Act and the Regional Haze Rule.

Ecology's "glide path" rationale is also misplaced because the agency failed to evaluate the Clean Air Act's reasonable progress factors in determining whether emission reductions may be necessary to ensure reasonable progress towards natural visibility in each Class I area that Washington's sources affect, as required by the Regional Haze Rule.[289] Ecology's misunderstanding of the legal requirements is also made clear in Ecology's communications with the National Park Service where it erroneously suggests that

> WA is successfully navigating regional progress goals and will continue to do so as we will also re-evaluate these sources during the next implementation period.[290]

Ecology cannot rely on its goals until it first conducts the required four-factor analyses, establishes emission limits in the SIP, and uses those limitations to set the goals. Indeed, the Regional Haze Rule explicitly requires Washington to make meaningful reductions to ensure reasonable progress towards the national goal of restoring visibility. In so doing, Ecology must provide a "robust demonstration," including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four-factors were taken into consideration. As discussed above, commenters have considered each of the sources with the greatest impacts at the Class I areas, and conclude that there are cost-effective control measures available, or at a minimum, that those facilities should have their emissions limits tightened to ensure current levels do not rise. Contrary to Ecology's assertions to the National Park Service, Ecology is not successfully navigating goals.

### J. Retirements Relied On to Justify No Control and No Upgrades Must be Reflected as Enforceable SIP Measures

Where Ecology is relying on retirements or operation changes to justify a no control and no upgrade option, Ecology must make those changes enforceable as SIP measures. To the extent

[287] 82 Fed. Reg. at 3093; see also 81 Fed. Reg. at 66,631.
[288] *EPA July 2021 Memo* at 15-16 (emphasis added).
[289] *See* 40 C.F.R. § 51.308(f)(2) ("Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State *and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State*.") (emphasis added); *id*. § 51.308(f)(3)(ii)(A)-(B).
[290] *Infra* note 321.

that a state declines to evaluate additional pollution controls for any source based on that source's planned retirement or decline in utilization, it must incorporate those operating parameters or assumptions as enforceable limitations in the second planning period SIP. The Clean Air Act requires that "[e]ach state implementation plan . . . *shall*" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the Act.[291] The Regional Haze Rule similarly requires each state to include "enforceable emission limitations" as necessary to ensure reasonable progress toward the national visibility goal.[292] Moreover, where a source plans to permanently cease operations or projects that future operating parameters (*e.g.*, limited hours of operation or capacity utilization) will differ from past practice, and if this projection affects whether additional pollution controls are cost-effective or necessary to ensure reasonable progress, then the state "must" make those parameters or assumptions into enforceable limitations.[293]

### K. The Draft SIP Lacks Provisions to Ensure Emission Limitations are Permanent, Enforceable and Apply at All Times

Contrary to the technical analysis presented in Stamper's Analysis and the attached Klafka Report demonstrating cost-effective controls at numerous sources, the proposed SIP merely includes for five sources in its regional haze plan:

- TransAlta Centralia Plant,
- Ash Grove Cement Plant,
- Cardinal FG Winlock Glass Plant,
- Intalco Aluminum Plant, and
- Alcoa Wenatchee Plant.

The Agreed Orders, Consent Decree and Permits in the proposed LTS "primarily rely on control requirements the owners already planned to meet under other Clean Air Act requirements (including under the first round regional haze plan) or reflect a commitment to conduct a four factor analysis of controls if/when a currently shutdown plant begins operations. In other words, Ecology's draft regional haze plan for the second implementation period does not include any additional regional haze control requirements for industrial sources of regional haze pollution beyond what was already required and on the books."[294] Contrary to the requirements in the Act and EPA's RH regulations, as discussed elsewhere in these comments, Ecology fails to make the emission reductions enforceable in the SIP. Furthermore, Ecology relies on retirements to avoid the Four-Factor Analysis and further measures to reduce emissions. If Ecology is relying in any way on possible or projected operations changes or retirements – the agency needs to make sure those changes will actually happen and that they are practically enforceable SIP measures by incorporating them into the SIP.

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[291] 42 U.S.C. § 7410(a)(2)(A).
[292] *See generally* 40 C.F.R. § 51.308(d)(3).
[293] *See* 40 C.F.R. pt. 51, App. Y § (IV)D.4.d.2.
[294] Stamper Report at 3.

## VI. Ecology Should Analyze the Environmental Justice Impacts of its Regional Haze SIP, and Ensure the SIP Will Minimize Harms to Disproportionately Impacted Communities

Ecology has both state and federal obligations to meaningfully consider and advance environmental justice in its regional haze SIP Unfortunately, the draft SIP's summary of what an environmental justice analysis entails falls short of these commitments.

### A. Environmental Justice Communities in Washington

In Seattle, 13 of the 14 heaviest industrial polluters are located within a half-mile of the places where marginalized communities live, work, play, and worship in Seattle. Of the 20 biggest regional haze producing facilities in Washington, two of them are located in the Duwamish Valley – Ash Grove Cement and Ardagh Glass.

Ardagh's facility has had a long history of violations in addition to inadequate or lack of required emissions reporting. Ardagh's glass melting furnaces emit quantities of $SO_2$ and NOx that place it in the "major source" Air Operating Permit program, and also significant qualities of total particulate matter (PM). For the last decade or more, the annual levels of fine particulate matter at the E. Marginal Way S (Duwamish) monitor in the industrial area, that includes Ardagh, have been higher than any monitor in the Puget Sound Clean Air Agency (PSCAA) four-county area. The Duwamish Valley's riverfront neighborhoods Georgetown and South Park are situated within two miles of the Ardagh Glass facility and have long been disproportionately exposed to contamination, cumulative environmental injustices, and subsequent adverse health-related outcomes. Residents who Georgetown and South Park have some of the highest health discrepancies in the City of Seattle. Childhood asthma hospitalization rates are the highest in the City. Heart disease death rates are 1.5 times higher than the rest of Seattle and King County. Life expectancy is 13 years shorter when compared to Laurelhurst in North Seattle; one of Seattle's wealthiest neighborhoods. Ardagh Glass has existed in the Duwamish Valley for over 100 years where old practices and technologies have led to a legacy of frequent air pollution violations.

By evaluating Ardagh Glass and other glass facilities as its own sector, we believe Washington state will identify emission-reducing options that if required will improve air quality and help achieve reasonable progress in this round of regional haze rulemaking. Ecology must also revisit the emission limitations for Ash Grove Cement, which must be strong, on par with requirements elsewhere and enforceable for environmental justice community purposes and SIP requirements. Historically, conservation and environmental work has concerned itself with protecting nature from people and has thus "siloed" its work (*e.g.*, mainstream conservation vs. environmental justice.) While this siloed approach has led to the protection of many vulnerable habitats, it ignores the reality that people live in concert with and are a part of nature; to protect one and not the other is a job half done. By considering viewshed protection and environmental justice at the same time, we can collectively begin to dismantle the silos that exist in conservation and environmental work and chart a new path forward.

## B. Environmental Justice in Washington

Ecology recognizes these environmental justice concerns, and that "pollution and environmental contamination can affect everyone living in Washington, but some people are significantly more burdened than others."[295] Furthermore, DOE explains that "[r]esearch shows that people of color, low-income people, and indigenous people are disproportionately harmed by environmental hazards … have real impacts on the lives of many in Washington, such as: …[h]igher rates of illness and disease … [m]ore frequent hospitalization [and] [l]ower life expectancy. We support the Department's commitment "to making decisions that do not place disproportionate burdens on disadvantaged communities," while "seeking to lift the weight of pollution and contamination borne by those communities." Additionally, we applaud DOE's "focus ... [of its] time and resources toward strategic actions to address these long-standing inequities" so that its actions "will lead to improvements in health and the environment, and more resilient communities in Washington."[296]

In addition to Ecology's commitments, the Governor's Interagency Council on Health Disparities (Governor's Council) was established by the Legislature in 2006 when it passed, and the Governor signed a bill to create it.[297] Under the law, the Governor's Council:

- Creates an action plan for eliminating health disparities by race, ethnicity, and gender in Washington.
- Convenes advisory committees to assist in the planning and development of specific issues in collaboration with several state agencies and non-government stakeholders.[298]

Additionally, Section 221, subsection 48 of the 2019-2021 biennial operating budget (Engrossed Substitute Senate Bill 1109) directed the Governor's Council to convene and staff an Environmental Justice Task Force,[299, 300] which includes a representative from Ecology. "The Task Force is responsible for recommending strategies to incorporate environmental justice principles into future state agency actions."[301] The EJ Task Force was required to "submit a final report by October 31, 2020 to include:

> 1. Guidance for using the Washington Environmental Health Disparities Map, hosted on the Department of Health's website to identify communities that are highly impacted by environmental justice issues with current demographic data.

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295 Department of Ecology, "Environmental Justice at Ecology," available at https://ecology.wa.gov/About-us/Accountability-transparency/Environmental-Justice. (Enclosure 9)
296 *Id.*
297 Governor's Interagency Council on Health Disparities, "The Council's Work," available at https://healthequity.wa.gov/TheCouncilsWork. (Enclosure 10)
298 *Id.*
299 "The Governor's Interagency Council on Health Disparities: State Policy Action Plan to Eliminate Health Disparities," (Jan. 2020) (2020 Council Report), available at https://healthequity.wa.gov/Portals/9/Doc/Publications/Reports/HDC-ActionPlan-Jan2020.pdf. (Enclosure 11)
300 Governor's Interagency Council on Health Disparities, 2019 and 2020 Environmental Justice Task Force Materials, available at https://healthequity.wa.gov/TaskForceMeetings/EnvironmentalJusticeTaskForce. (Enclosure 12)
301 2020 Council Report at 6.

2. Best practices for increasing meaningful and inclusive community engagement that takes into account barriers to participation.
3. Measurable goals for reducing environmental health disparities for each community in Washington state and ways in which state agencies may focus their work towards meeting those goals.
4. Model policies that prioritize highly impacted communities and vulnerable populations for the purpose of reducing environmental health disparities and advancing a healthy environment for all residents. The Governor's Council includes several task force groups, including the Environmental Justice Task Force.[302]

The EJ Task Force's posted materials for 2019 and 2020[303] demonstrate considerable activity and include: Task Force meeting agendas, minutes and materials; Mapping Subcommittee meeting agendas and minutes; Community Engagement Subcommittee agendas and minutes; Task Force Feedback Listening Session agenda minutes, materials and minutes; and Task Force Work Group agenda and minutes.[304] However, there is no information available on the final report that was due October 31, 2020. The January 2020, Report of the Governor's Council's recognizes EPA's definition of environmental justice: "[t]he Environmental Protection Agency defines environmental justice as, '…the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.'"[305]

### C. Consideration of Environmental Justice to Comply with Executive Orders

There are additional legal grounds for considering environmental justice when determining reasonable progress controls. Under the CAA, states are permitted to include in a SIP measures that are authorized by state law but go beyond the minimum requirements of federal law.[306] Ultimately, EPA will review the haze plan that Washington submits, and EPA will be required to ensure that its action on Washington' haze plan addresses any disproportionate environmental impacts of the pollution that contributes to haze. Executive Orders in place since 1994, require federal executive agencies such as EPA to:

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[302] *Id.*
[303] Environmental Justice Task Force Meeting Materials, available at https://healthequity.wa.gov/TaskForceMeetings/EnvironmentalJusticeTaskForce. (Enclosure 13)
[304] *Id.*
[305] 2020 Council Report at 6, citing EPA's Environmental Justice website, https://www.epa.gov/environmentaljustice. (Enclosure 14)
[306] *See Union Elec. Co v. EPA*, 427 U.S. 246, 265 (1976) ("States may submit implementation plans more stringent than federal law requires and . . . the Administrator must approve such plans if they meet the minimum requirements of s 110(a)(2)."); *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1126 (10th Cir. 2009) (quoting *Union Elec. Co.*, 427 U.S. at 265) ("In sum, the key criterion in determining the adequacy of any plan is attainment and maintenance of the national air standards . . . 'States may submit implementation plans more stringent than federal law requires and [ ] the [EPA] must approve such plans if they meet the minimum [Clean Air Act] requirements of § 110(a)(2).'"); *BCCA Appeal Group v. EPA*, 355 F.3d 817, 826 n. 6 (5th Cir. 2003) ("Because the states can adopt more stringent air pollution control measures than federal law requires, the EPA is empowered to disapprove state plans only when they fall below the level of stringency required by federal law.")

> [M]ake achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations"[307]

On January 27, 2021, the current Administration signed "Executive Order on Tackling the Climate Crisis at Home and Abroad."[308] The new Executive Order on climate change and environmental justice amended the 1994 Order and provides that:

> It is the policy of [this] Administration to organize and deploy the full capacity of its agencies to combat the climate crisis to implement a Government-wide approach that reduces climate pollution in every sector of the economy; … protects public health … delivers environmental justice …[and that] … [s]uccessfully meeting these challenges will require the Federal Government to pursue such a coordinated approach from planning to implementation, coupled with substantive engagement by stakeholders, including State, local, and Tribal governments.[309]

Washington can facilitate EPA's compliance with these Executive Orders by considering environmental justice in its SIP submission.

### D. EPA's Regional Haze Guidance and Clarification Memo for the Second Implementation Period

EPA's 2021 Clarification Memo directs states to take into consideration environmental justice concerns and impacts in issuing any SIP revision for the second planning period.[310] EPA's 2019 Regional Haze Guidance for the Second Planning Period specifies, "States may also consider any beneficial non-air quality environmental impacts."[311] This includes consideration of environmental justice in keeping with other agency policies. For example, EPA also pointed to another agency program that states could rely upon for guidance in interpreting how to apply the non-air quality environmental impacts standard:[312]

> When there are significant potential non-air environmental impacts, characterizing those impacts will usually be very source- and place-specific. Other EPA guidance intended for use in environmental impact assessments under the National Environmental Policy Act may be informative, but not obligatory to follow, in this task.

Additionally, a collection of EPA policies and guidance related to the National Environmental Policy Act ("NEPA") is available at https://www.epa.gov/nepa/national-environmental-policy-

[307] Exec. Order No. 12898, § 1-101, 59 Fed. Reg. 7629 (Feb. 16, 1994), as amended by Exec. Order No. 12948, 60 Fed. Reg. 6381 (Feb. 1, 1995).
[308] Exec. Order No. 14008, 86 Fed. Reg. 7619 (Jan. 27, 2021).
[309] *Id.* at § 201.
[310] EPA July 2021 Memo at 16.
[311] EPA 2019 RH Guidance at 49.
[312] *Id.* at 33.

act-policies-and-guidance. One of these policies concerns Environmental Justice.[313] Ecology should consider these sources of information in conducting a meaningful environmental justice analysis.

### E. EPA has a Repository of Material Available for Considering Environmental Justice

In addition to the NEPA guidance materials referenced above, EPA provides a wealth of additional material.[314] The most important aspect of assessing Environmental Justice is to identify the areas where people are most vulnerable or likely to be exposed to different types of pollution. EPA's EJSCREEN tool can assist in that task. It uses standard and nationally consistent data to highlight places that may have higher environmental burdens and vulnerable populations.[315]

### F. EPA Must Consider Environmental Justice

As occurred in the first planning period, if a state fails to submit its SIP on time, or if EPA finds that all or part of a state's SIP does not satisfy the Regional Haze regulations, then EPA must promulgate its own Federal Implementation Plan to cover the SIP's inadequacy ("FIP"). Should EPA promulgate a FIP that reconsiders a state's four-factor analysis, it is completely free to reconsider any aspect of that state' analysis. The two Presidential Executive Orders referenced above require that federal agencies integrate Environmental Justice principles into their decision-making. EPA has a lead role in coordinating these efforts, and recently EPA Administrator Regan directed all EPA offices to clearly integrate environmental justice considerations into their plans and actions.[316] Consequently, should EPA promulgate a FIP, it has an obligation to integrate Environmental Justice principles into its decision-making. The non-air quality environmental impacts of compliance portion of the third factor, is a pathway for doing so.

### G. Ecology Must Consider Environmental Justice under Title VI of the Civil Rights Act

As EPA must consider Environmental Justice, so must Ecology and all other entities that accept Federal funding. Under Title VI of the Civil Rights Act of 1964, "no person shall, on the ground of race, color, national origin, sex, age or disability be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity…". Ecology has an obligation to ensure the fair treatment of communities that have been

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[313] *See*, EPA Environmental Justice Guidance for National Environmental Policy Act Reviews, https://www.epa.gov/nepa/environmental-justice-guidance-national-environmental-policy-act-reviews.

[314] *See,* EPA: Learn About Environmental Justice, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice. (Enclosure 15)

[315] *See*, EPA EJSCREEN: Environmental Justice Screening and Mapping Tool, Additional Resources and Tools Related to EJSCREEN, https://www.epa.gov/ejscreen/additional-resources-and-tools-related-ejscreen.

[316] *See*, EPA News Release, EPA Administrator Announces Agency Actions to Advance Environmental Justice, *Administrator Regan Directs Agency to Take Steps to Better Serve Historically Marginalized Communities* (April 7, 2021), https://www.epa.gov/newsreleases/epa-administrator-announces-agency-actions-advance-environmental-justice. (Enclosure 16)

environmentally impacted by sources of pollution. That means going beyond the current analysis conducted to inform the "meaningful involvement" of impacted communities; environmental justice also requires the "fair treatment" of these communities in the development and implementation of agency programs and activities, including those related to the SIP.

Ecology should conduct a thorough analysis of the current and potential effects to impacted communities from sources considered in the SIP as well as those facilities identified by commenters and other stakeholders but not reviewed by Ecology. By not conducting this analysis and including the benefits of projected decline in emissions to these communities in their determination of the included emission sources, Ecology is not fulfilling its obligations under the law. Moreover, the state is making a mockery of Title VI by not using the SIP requirements to bring about the co-benefits of stronger reductions measures and reduce harms based on continued emissions.

### H. Ecology's Efforts on Environmental Justice Are Inadequate

While we appreciate Ecology's preliminary environmental justice analysis, it falls short. Ecology's proposed SIP explains that

> Ecology consulted with our EJ coordinator to determine how best to address EJ concerns within the constraints of the Regional Haze Rule and guidance. Based upon her guidance and the use of EJSCREEN, we took the following actions:
>
> > • Identified the population characteristics of the people affected by the action (such as minority populations, low-income populations, non-English speaking populations, and tribes)
> > • Assessed and addressed disproportionately high and adverse human health or environmental effects on minority populations and low-income populations
> > • Planned for and facilitated the meaningful involvement of affected communities in the processes
> > • Ensured that potentially affected populations have appropriate opportunity to learn about, participate in, and influence Ecology's decisions and actions.[317]

The draft SIP and its appendices lack

- The EJSCREEN analysis Ecology generated from EPA's online system.
- The information Ecology developed in assessing and addressing disproportionately high and adverse human health or environmental effects on minority populations and low-income populations.
- How it facilitated meaningful involvement of affected communities in the processes.
- How Ecology ensured that potentially affected populations have appropriate opportunity to learn about, participate in, and influence Ecology's decisions and actions.

Furthermore, the draft SIP merely makes the following overarching claims:

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[317] Draft SIP at 22.

> The long-term strategy in this regional haze SIP revision includes emission reductions from permits and state rules. The visibility benefits of these controls provide co-benefits to the communities that are in the vicinity where emission reductions occur. An example of such controls would be federal fuel and engine rules that have resulted in large reductions in mobile source air pollution and improvements in visibility.[318]

Ecology's draft SIP does not disclose the fact that many of the reasonable progress sources are located in communities of color and many live below the poverty line.

Consistent with the Governor's Council, the Environmental Task Force's efforts, and the federal requirements, Ecology should analyze the environmental justice impacts of its second planning period haze SIP. For those RP sources located near a low-income or minority community that suffers disproportionate environmental harms, Ecology's four-factor analysis for that source should take into consideration how each considered measure would either increase or reduce the environmental justice impacts to the community. Such considerations will not only lead to sound policy decisions but are also pragmatic as pointed out above, most of the same sectors and sources implicated under the regional haze program are of concern to disproportionately impacted communities in Washington. Thus, considering the intersection of these issues and advancing regulations accordingly will help deliver necessary environmental improvements across issue areas. Such consideration and associated action will reduce uncertainty for the regulated community, increase the state's regulatory efficiency, result in more rational decision making and be consistent with the Washington State Legislature's and Governor's directives, priorities and funding to focus on policies that "prioritize highly impacted communities and vulnerable populations for the purpose of reducing environmental health disparities and advancing a healthy environment for all residents."[319]

Consistent with legal requirements and government efficiency, we urge Ecology to take impacts to EJ communities, like the ones we have expressed for the Ash Grove Cement and Ardagh Glass facilities, into consideration as it evaluates all sources that impact regional haze.

## VII. Ecology Should Meaningfully Reconsider and Adapt Its SIP to Reflect Comments from the FLMs

The RHR and the CAA require that states consult with the FLMs that manage the Class I Areas impacted by a state's sources. Because the FLMs' role is to manage their resources – including air quality – Ecology should meaningfully consider and adapt its SIP measures to reflect comments and suggestions from the FLMs. Ecology has neither fully considered nor adapted its proposed SIP to reflect information and comments it received during the FLM consultation.

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[318] Draft SIP at 23; and also explains that "[t]here are several emission control grant programs in Washington that take into account EJ concerns in awarding grants or have co-benefits for nearby disadvantaged communities. These include the wood stove buy-back and exchange program (Chapter 173-433 WAC), the low emission vehicles 2021 rulemaking to reduce emissions around ports, distribution centers, and freight corridors (which tend to be located within disadvantaged communities), and the Volkswagen enforcement action grants that prioritizes projects in or near communities disproportionately-impacted by diesel fumes." *id.*

[319] 2020 Council Report at 6.

Indeed, many of Ecology's responses were non-responsive and/or inconsistent with the legal CAA and RHR requirements. For example:

- Perceptibility should not be considered in screening source controls for reasonable progress;[320]
- Visibility improvement is not a fifth-factor "off-ramp" for emission controls;[321]

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[320] The NPS noted that "Ecology appears to have set 0.13 dv as its criterion for what constitutes a significant improvement in visibility. Ecology provides no justification for this criterion. For comparison, EPA used 0.3% change in extinction, which is approximately equal to 0.03 dv, as its significance criterion in its TX FIP. However, in determining if a visibility improvement was adequate, Ecology dismissed greater improvements at 16 Class I areas." *Id.* at A-16, citing Feb. 19, 2021 email from NPS. Ecology's reply

> The comment is incorrect. Ecology did not set 0.13 dv as a criterion. Ecology also did not set the BART 0.5 dv as a criterion. Instead, Ecology stated the following in Chapter 7 (p. 73) of the analysis:
>
> An impact of 0.5 dv was considered the minimum visibility impact for a source to be subject to BART. While a potential visibility improvement of 0.5 dv or more would have clearly triggered a more in-depth evaluation of the RACT/Four-Factor reasonable progress factors, the significantly smaller annual visibility improvements that have been modeled were determined to be too small to pursue further at this time.
>
> Considering that one deciview is generally considered to be the minimum amount of visibility change the average person can detect, Ecology would not require the controls listed in the 2016 RACT analysis for non-detectable (to humans) visibility improvements of only 0.03 dv. *Id.*.

[321] The NPS expressed concern that "[u]nder the Reasonable Progress provisions of the Clean Air Act, visibility improvement is not a fifth-factor "off-ramp" for emission controls. EPA guidance has placed certain constraints on its use and we need to be sure we understand how Ecology is applying this 'fifth-factor.'" *Id.* at A-6, citing Nov. 19, 2020 email from NPS. Ecology's response what that

> Washington State has a Reasonably Available Control Technology (RACT) provision that can be applied to attainment areas (unlike some other states and EPA which generally apply RACT exclusively to non-attainment areas). The five factors of Washington State's RACT rule are listed on page 4 of the 2016 RACT Analysis. Two of the factors (impact of source on air quality, and impact of additional controls on air quality) are described in Chapter 5 of the 2016 RACT Analysis. Two other factors (available controls; and cost) have an entire chapter devoted to each factor. Chapters 3 and 4 of the 2016 RACT Analysis describe in depth a fifth factor in the WA RACT process (emission reductions to be achieved by additional controls).
>
> According to Washington State University, which prepared Appendix C of the 2016 RACT Analysis, "Results from this modeling study show that RACT implementation in the pulp and paper industry does little to improve visibility in Class I areas." They found that "the 8th highest deciview change was less than 0.05 dv at all of the IMPROVE sites." This is a valid off-ramp for using the WA RACT provisions to address regional haze.
>
> In terms of 4-factor analyses, the pulp mill information presented to Ecology fully satisfies the current EPA requirements for regional haze 4-factor analysis as specified in the August 20, 2019 EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (2019 EPA Guidance). Based on the current 2019 EPA Guidance, and confirmed on November 3, 2020 in consultation with EPA, Ecology is in full compliance with the regional haze rule by deciding to not pursue controls for pulp mills at this time.

- If visibility benefit analyses are undertaken, they should reference a clean – not dirty –background;[322]
- RACT, which Ecology describes as a "C-grade" control or emission limit, clearly is less stringent than emission limits developed from application of the four-factor reasonable progress analysis;[323]
- Use of an outdated emission inventory is not allowed under the RHR;[324]
- The state must document support for its proposed SIP decisions;[325] and
- Reliance on the lack of a federal action by Department of Interior in another program that does apply to existing sources is not a legitimate basis to justify no controls at those sources.[326]

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> In terms of Reasonable Progress provisions of the Clean Air Act, WA is successfully navigating regional progress goals and will continue to do so as we will also re-evaluate these sources during the next implementation period. *Id.* at A-6.

[322] *Id.* at A-15. ("…modeling annual emissions against a "dirty" background [*e.g.*, Ecology's 2016 Pulp and Paper analysis] underestimates the benefits of reducing emissions. It is generally recognized that NOx emissions in the local climate have an enhanced impact upon visibility impairment and their reductions should not have been excluded." The NPS further explained that "Ecology modeled 2007 baseline actual emission rates and the potential RACT emission rates using CMAQ against a "dirty" background. This is contrary to EPA guidance and underestimates the visibility benefits of reducing emissions." NPS Formal Consultation PowerPoint Presentation (June 16, 2021), at 17. (Enclosure 17) ("NPS 2021 Consultation")
[323] In responding to a question from the FLM's that asked, "What is the basis for this assumption?" (RE: RACT cost of 50% of BACT cost), Draft SIP, Appendix A at A-10, citing Nov. 19, 2020 email from NPS, Ecology explained that

> When not being applied to address non-attainment area concerns, RACT in Washington State is understood by at least three agencies (NWCAA, PSCAA, and Ecology) to be a *C-grade level control or emission limit*. There is a precedent threshold in a previous WA state RACT determination from p. 77 of 107 of the combined (Ecology/ NWCAA/ PSCAA) Washington State Oil Refinery RACT – TSD FINAL – 11/25/2013: "The proposed RACT defines a reasonably efficient refinery… comparable to or above the 50% percentile of similar-sized US refineries…" *Id.* (emphasis added)

Further explaining that "Ecology used its discretion to also apply a similar type of 50% factor to BACT costs to arrive at a RACT cost. In a December 5, 2019 conversation between Ecology and EPA, EPA agreed that this was a reasonable approach." *Id.* EPA's final action comes *after* notice and comment rulemaking, not before.

[324] *Id.* at A-15. 40 C.F.R. § 51.308(f)(3)(iii).
[325] "The State must 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 Federal area it affects." 40 C.F.R. § 51.308(f)(3)(iii). Which is contrary to Ecology's assertion that

> Ecology is not required to put all documents that support a SIP determination into a SIP. The amount of documentation from all the different programs and permits that support SIP determinations is immense. It is not historical practice to include all such documentation in a SIP and is problematic due to changing conditions (in permits for example), which may not be related to the SIP determination. In such situations (and many others), the SIP would unnecessarily contain inaccurate and outdated information." *Id*. at A-1.

[326] Ecology's use of the FLM's lack of adverse impact determination on existing chemical pulp mills in Washington state to justify ignoring opportunities for emission reductions during this planning period is misplaced and as the FLM's explain "irrelevant." *Id.* at A-12. As the FLM's accurately explained to Ecology:

**Conclusion**

We appreciate Ecology's consideration of these comments and ask the agency to revise its SIP accordingly. Please do not hesitate to contact us with any questions.

Sincerely,

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The potential for an adverse impact determination only occurs when new emissions from a major source or major modification rise to the level that the FLM has no other recourse. Instead of these rare instances, the facilities under review here are already in existence and have much greater emissions. Due to such congoing emissions, the DoI made a determination in 1985 that all Class I areas it administered were experiencing impaired visibility—that determination has not been changed and is supported by current visibility monitoring data. For example, our monitoring data indicates that visibility in Mount Rainier, North Cascades, and Olympic national parks is "fair" and unchanging. *Id.*, citing Nov. 19, 2020 email from NPS.

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Enclosures

## List of Enclosures

1. Victoria R. Stamper, "Review and Comments on Washington Department of Ecology's Draft Regional Haze Plan for the Second Implementation Period: Long Term Strategy and Four-Factor Analysis of Controls" (Nov. 19, 2021), with exhibits.
2. Steven Klafka, P.E. BCEE, Environmental Engineer, Wingra Engineering, S.C, "The Four-Factor Reasonable Progress Analysis for Ardagh Glass" (Jan. 27, 2021) ("Klafka Report") (Enclosure 2).
3. National Parks Conservation Association comments submitted on the Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), and Intalco Agreed Order 18216 (Whatcom County) (Dec. 3, 2020).
4. Comments submitted by the Conservation Organizations on February 16, 2021 (submitted with corrections on February 19, 2021) for Informal comment period: Regional Haze SIP Revision - 2nd 10-Year Plan.
5. "Petition for Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," submitted by National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Coalition to Protect America's National Parks, Appalachian Mountain Club, Western Environmental Law Center and Earthjustice, to former EPA Administrator Andrew Wheeler (May 8, 2020).
6. *National Parks Conservation Association v. State of Washington, Department of Ecology; and BP West Coast Products, LLC*, PCHB No. 10-162, Department of Ecology's Prehearing Brief (April 12, 2018).
7. *National Parks Conservation Association v. State of Washington, Department of Ecology; and BP West Coast Products, LLC*, PCHB No. 10-162, Hearing Transcript, Volume IV (April 26, 2018).
8. "Prehearing Statement of the Colorado Department of Public Health and Environmental, Air Pollution Control Division," *In the Matter of Proposed Revisions to Regulation No 23* (Oct. 7, 2021).
9. Department of Ecology, "Environmental Justice at Ecology," available at https://ecology.wa.gov/About-us/Accountability-transparency/Environmental-Justice.
10. Governor's Interagency Council on Health Disparities, "The Council's Work," available at https://healthequity.wa.gov/TheCouncilsWork.
11. "The Governor's Interagency Council on Health Disparities: State Policy Action Plan to Eliminate Health Disparities," (Jan. 2020) (2020 Council Report), available at https://healthequity.wa.gov/Portals/9/Doc/Publications/Reports/HDC-ActionPlan-Jan2020.pdf.
12. Governor's Interagency Council on Health Disparities, Environmental Justice Task Force Materials, available at https://healthequity.wa.gov/TaskForceMeetings/EnvironmentalJusticeTaskForce.
13. Environmental Justice Task Force Meeting Materials, available at https://healthequity.wa.gov/TaskForceMeetings/EnvironmentalJusticeTaskForce.
14. EPA's Environmental Justice website, https://www.epa.gov/environmentaljustice.
15. EPA: Learn About Environmental Justice, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.
16. EPA News Release, EPA Administrator Announces Agency Actions to Advance Environmental Justice, *Administrator Regan Directs Agency to Take Steps to Better Serve*

*Historically Marginalized Communities* (April 7, 2021), https://www.epa.gov/newsreleases/epa-administrator-announces-agency-actions-advance-environmental-justice.
17. NPS Formal Consultation PowerPoint Presentation (June 16, 2021).

# Enclosure 1

**Review and Comments on**
**Washington Department of Ecology's**
**Draft Regional Haze Plan for the Second Implementation Period:**
**Long Term Strategy and Four-Factor Analysis of Controls**

By Victoria Stamper

November 19, 2021

Prepared for
National Parks Conservation Association

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The Clean Air Act's regional haze provisions require states to adopt periodic, comprehensive revisions to their implementation plans for regional haze on 10-year increments to achieve reasonable progress towards the national visibility goal. The plan revision for the second implementation period was due to be submitted to EPA by July 31, 2021.[1] As part of the comprehensive revisions to their regional haze plan, states must submit a long-term strategy that includes enforceable emission limits and other measures as may be necessary to make reasonable progress towards the national visibility goal.[2]

To that end, in October of 2021, the Washington Department of Ecology (Ecology or WDOE) made available its plan for addressing reasonable progress toward the national visibility goal for Class I areas.[3] Ecology has proposed to include requirements for five facilities in its regional haze plan: the TransAlta Centralia Plant, the Ash Grove Cement Plant, the Cardinal FG Winlock Glass Plan, the Intalco Aluminum Plant, and the Alcoa Wenatchee Plant. However, the Agreed Orders, Consent Decree, and Permits that it has included in its proposed Long Term Strategy primarily rely on control requirements the owners already planned to meet under other Clean Air Act requirements (including under the first round regional haze plan) or reflect a commitment to conduct a four factor analysis of controls if/when a currently shutdown plant begins operations. In other words, Ecology's draft regional haze plan for the second implementation period does not include any additional regional haze control requirements for industrial sources of regional haze pollution beyond what was already required and on the books.

There are several other facilities that met Ecology's criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period for which Ecology is not currently proposing to adopt any new controls as part of its second round regional haze plan. Yet, there are pollution controls (primarily for nitrogen oxides (NOx)) that Ecology found could be cost effectively installed at these sources to significantly reduce emissions of the visibility-impairing pollutants. Ecology has indicated that it will address these sources in a subsequent revision to its regional haze plan. In other words, Ecology's regional haze plan for the second implementation period is not complete.

The four factors that must be considered in determining appropriate emissions controls for the second implementation period are as follows: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any source being evaluated for controls.[4] EPA states that it anticipates the cost of controls being the predominant factor in the evaluation of reasonable

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[1] 40 C.F.R. §51.308(f).
[2] 40 C.F.R. §51.308(f)(2)(i); 42 U.S.C. § 7491(b)(2). Under the Clean Air Act, state implementation plans must include "include enforceable emission limitations and other control measures, means, or techniques . . . , as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter." 42 U.S.C. § 7491(a)(2)(A). An emission limitation is a "requirement" that "limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." *Id*. § 7602(k).
[3] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021.
[4] 40 C.F.R. §51.308(f)(2)(i).

progress controls and that the other factors will either be considered in the cost analysis or not be a major consideration.[5] Such is the case with the add-on controls evaluated in this report. Specifically, the remaining useful life of a source is taken into account in assessing the length of time the pollution control will be in service to determine the annualized costs of controls. If there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution controls is generally considered the remaining life of the source.[6] In addition, costs of energy for selective noncatalytic reduction (SNCR), selective catalytic reduction (SCR), and other controls at a particular source are considered in determining the annual costs of these controls, which means that the bulk of the non-air quality and energy impacts are generally taken into account in the cost effectiveness analyses as is the remaining useful life of a unit. With respect to the length of time to install controls, that is not generally an issue for SCR or SNCR which can and have been installed within three to five years of promulgation of a requirement to install such controls.[7] In any event, EPA's August 20, 2019 regional haze guidance states that, with respect to controls needed to make reasonable progress, the "time necessary for compliance" factor does not limit the ability of EPA or the states to impose controls that might not be able to be fully implemented within the planning period; more specifically, when considering the time necessary for compliance, a state may not reject a control measure because it cannot be installed and become operational until after the end of the implementation period."[8]

This report comments on the proposed Long Term Strategy and on Ecology's review of the four-factor analyses of pollution controls that were submitted for facilities in Washington.

## I. Background.

Ecology used 2014 emissions data and Q/d (i.e., the ratio of a source's visibility-impairing emissions in tons per year (Q) divided by the source's distance from the nearest Class I area (d)) to identify sources to prioritize for evaluation of regional haze controls for its plan for the second implementation period. Ecology based on their review only on major sources. Ecology did not explain whether it focused on major sources based on the actual emissions of each source or based on the potential emissions of each source, and that should be clarified. Ecology used a

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[5] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 37.

[6] *Id.* at 33. While we are aware that some EGUs evaluated in this report have planned decommission dates, we are not aware that any of those dates are enforceable. Thus, for all of the EGUs evaluated for add-on NOx controls in this report, we assumed that the expected useful life of the pollution control being evaluated was the remaining useful life of the source, as directed to by EPA in its August 2019 guidance.

[7] For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan.

[8] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 41 (it would be inconsistent with the regional haze regulations to discount an otherwise reasonable control "simply because the time frame for implementing it falls outside the regulatory established implementation period.").

Q/d value of 10 or higher as a cutoff for selecting major sources and included two other facilities with a lower than 10 Q/d value because they were in a selected source category. Based on this analysis, Ecology came up with the following list of sources to evaluate for controls.

**Table 1. WDOE's List of Sources to Conduct a Four-Factor Analysis of Controls**[9]

| Facility Site Name | Q (tons of NOx, PM10, SO2, and NH3) | D (km) to nearest Class I area | Q/d | Nearest Class I Area | Number of Class I Areas Impacted (NPCA Analysis)[10] | Source Category |
|---|---|---|---|---|---|---|
| TransAlta Centralia Generation LLC | 10,749.4 | 71.8 | 149.8 | Mount Rainier NP | | Coal-powered electric |
| McKinley Paper Company | 367.2 | 4.4 | 83.1 | Olympic NP | 1 | Pulp and Paper Plant |
| Alcoa Primary Metals Wenatchee Works | 3,461.7 | 42.8 | 80.9 | Alpine Lakes WA | | Alumina Refining and Aluminum Production |
| Alcoa Primary Metals Intalco Works | 5,658.5 | 78.9 | 71.7 | North Cascades NP | 38 | Alumina Refining and Aluminum Production |
| BP Cherry Point Refinery | 2,945.1 | 80.8 | 36.4 | North Cascades NP | 14 | Petroleum refineries |
| Tesoro Northwest Company | 2,312.3 | 75.4 | 30.7 | Olympic NP | 10 | Petroleum refineries |
| WestRock Tacoma | 1,353.7 | 48.4 | 27.9 | Mount Rainier NP | 10 | Pulp, Paper, and Paperboard Mills |

[9] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 161-162.
[10] Based on NPCA's Regional Haze Fact Sheet for Washington, Sources of Visibility Impairing Pollution in Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view. Note that neither the TransAlta Centralia power plant nor the Alcoa Wenatchee plant were included in NPCA's evaluation, presumably because of TransAlta's prior requirement to decommission the Centralia coal-fired power plant by 2025 and because the Alcoa Wenatchee plant has been shut down since 2015. Note that in the NPCA fact sheet, the Weyerhauser NR Company plant is now the Nippon Dynawave plant, and the Boise Paper facility is now the Packaging Corp. of America plant. Note that the U.S. Oil refinery in Tacoma is not in NPCA's Fact Sheet.

| Facility Site Name | Q (tons of NOx, PM10, SO2, and NH3) | D (km) to nearest Class I area | Q/d | Nearest Class I Area | Number of Class I Areas Impacted (NPCA Analysis)[10] | Source Category |
|---|---|---|---|---|---|---|
| Nippon Dynawave Packaging Company | 2,656.0 | 104.8 | 25.3 | Mount Adams WA | 21 | Paperboard Mills |
| Puget Sound Refining Co. (Shell) | 1,793.1 | 73.0 | 24.5 | Olympic NP | 8 | Petroleum Refineries |
| Pt Townsend Paper Corp. | 848.0 | 35.0 | 24.2 | Olympic NP | 5 | Paper (not Newsprint) Mills |
| Ash Grove Cement Co., E Marginal | 1,243.6 | 53.8 | 23.1 | Alpine Lakes WA | 9 | Cement Manufacturing |
| Cosmo Specialty Fibers, Inc. | 973.8 | 58.2 | 16.7 | Olympic NP | 5 | Paperboard Mills |
| WestRock Longview, LLC | 1,574.2 | 100.7 | 15.6 | Mount Adams WA | 10 | Paperboard Mills |
| Georgia-Pacific Consumer Operations LLC | 653.0 | 45.4 | 14.4 | Mount Hood WA | 5 | Paper (except Newsprint) Mills |
| Phillips 66 | 840.6 | 77.2 | 10.9 | North Cascades NP | 5 | Petroleum Refineries |
| Cardinal FG Winlock | 859.8 | 80.1 | 10.7 | Mount Rainier NP | 6 | Flat Glass Manufacture |
| Packaging Corp. of America (PCA), Wallowa | 1,048.3 | 111.5 | 9.4 | Eagle Cap WA | 16 | Paperboard Mills |
| U.S. Oil & Refining Co. | 149.2 | 46.4 | 3.2 | Mount Rainier NP | | Oil Refinery |

Of the above list, there were a few sources for which Ecology did not request a four-factor analysis of controls for, because "[s]ome of these facilities had existing legal requirements or pending permit actions to reduce emissions."[11] Those facilities were the TransAlta Centralia power plant, the Cardinal FG Winlock glass plant, and the Ash Grove Cement Plant.[12] Ecology also will only request a four-factor analysis of controls for the Intalco Aluminum Plant and the Alcoa Wenatchee Aluminum Plant if the plants restart operations.[13] In addition, it appears that Ecology did not request a four-factor analysis of controls for the McKinley Paper Company located near Port Angeles, and Ecology's draft regional haze plan does not mention this facility other than to show its Q/d value of 83.1 (making it the facility with the second highest Q/d value).[14]

Its Long Term Strategy addresses the Centralia Power Plant, Intalco and Alcoa Wenatchee Aluminum plants, the Ash Grove Cement Plant, and the Cardinal FG Winlock Glass Plant, although it does not require additional pollution control measures other than what was already required for these facilities. This is discussed in Section II below.

For the remaining facilities for which Ecology requested four-factor analyses of controls, Ecology selected the refineries as the first priority of sources to focus on for regional haze controls. Ecology's reasons for prioritizing the refineries included the following:

- Four of the five refinery facilities are located in the Puget trough, west of several Class 1 Areas. Their cumulative regional haze causing emissions influence the same Class 1 Areas.

- Predominant winds direct the emissions from the refineries toward several Class 1 Areas.

- The refineries' potential emission reductions of 4,200 tons per year account for the vast amount of potential emission reductions.

WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 166.

Ecology prioritized pulp and paper mills lower than refineries because they "are not located as close to each other as the refineries so they do not have as great of a cumulative effect."[15] Ecology also states that the potential reduction in regional haze emissions from pulp and paper mills is "vastly less than the potential refinery emission reductions."[16]

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[11] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 163.
[12] *Id.* at 212.
[13] *Id.* at 178, 180-181.
[14] Note that the Technical Support Document for the current operating permit for the McKinley Plant states that the McKinley facility was purchased from Nippon Paper Industries USA Co. in 2017. *See* https://www.orcaa.org/wp-content/uploads/TSD_McKinley_Final_17August2021.pdf. This is a different facility than the Nippon Dynawave facility that is located in Longview, Washington.
[15] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 166.
[16] *Id.* at 167.

The regional haze plan regulations require states to include a description of the criteria that it used to determine the sources or groups of sources that it evaluated for controls,[17] which Ecology has done in its draft regional haze plan. As stated above, it selected sources with a Q/d value equal to or greater than 10. EPA's July 8, 2021 guidance memo states that "[u]nder the [regional haze rule], each state has an obligation to submit a long-term strategy that addresses the regional haze visibility impairment resulting from emissions from within that state."[18] While states have the discretion to select any reasonable source selection methodology, the source selection methodology must "produce a reasonable outcome."[19] In the case of Ecology's source selection process and four factor analyses, the outcome of its approach as proposed in the draft regional haze plan is a long term strategy that does not include any control measures other than those control measures that were either previously imposed to meet best available retrofit technology (BART), i.e., at the TransAlta Centralia Plant, that were already required under other requirements, i.e., Ash Grove Cement Plant, that were voluntarily proposed by the source due to an increase in capacity (i.e., Cardinal FG Winlock Glass Plant), or that simply require the submittal of a four-factor analysis of controls if the currently "curtailed" plants start operating again (Intalco Aluminum and Alcoa Wenatchee). Ecology's selection of sources to include in its long term strategy ignored the fact that Ecology has found cost effective control options for several sources identified in Table 1 above. Ecology states that it must follow its reasonably available control technology (RACT) rule requirements before it can establish legally establish control requirements.[20] Given that the regional haze pollution controls are required to be part of the regional haze plan pursuant to 40 C.F.R. 51.308(f)(2)(i), Ecology's regional haze plan for the second implementation period is not yet complete or it otherwise fails to meet the requirements for regional haze plans. Given that Ecology's Public Review Draft is stated to be its State Implementation Plan (SIP) revision for the second regional haze plan implementation period of 2018 to 2028, it will be assumed for the purpose of these comments that the Public Review Draft is the complete plan to be submitted to EPA for approval. This report provides comments and analyses on the source-specific requirements of Ecology's proposed Long Term Strategy of the Public Review Draft and also on the other sources evaluated for control by Ecology in the context of its regional haze plan for the second implementation period.

[17] 40 C.F.R. 51.308(f)(2)(i).
[18] July 8, 2021 EPA RHR Clarifications Memo at 3. See also 40 C.F.R. 51.308(f)(2).
[19] *Id.*
[20] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 163.

## II. Review and Comments on Ecology's Proposed Long Term Strategy Source-Specific Control Measures

Ecology lists the following source-specific emission limits and shutdowns of its long term strategy:

- TransAlta Centralia Generation BART order revision, which ceased coal-fired operation of one boiler in December 2020 and will cease coal-fired operation of the other boiler by the end of 2025.

- Cardinal FG Winlock Glass Plant, which voluntarily requested a permit to install selective catalytic reduction (SCR) on its glass furnace in conjunction with an increase in glass production capacity. A permit was issued authorizing these actions on February 11, 2001, and Ecology states that the SCR should be installed and operating by 2022.

- Ash Grove Cement Company, which entered into a Consent Decree in 2013 with EPA, Ecology, and other state agencies that required optimization of the Seattle Kiln to reduce NOx emissions and is currently subject to a NOx limit of 5.1 pounds per ton ("lb/ton") of clinker.

- Alcoa Wenatchee and Intalco Aluminum, which are both currently in "curtailment due to market conditions," for which ECOLOGY has proposed Agreed Orders to require the plants to conduct and submit a four-factor analysis of controls if they decide to restart operations.[21]

### A. TransAlta Centralia Generation

The TransAlta Centralia Generating Station is a coal-fired power plant located near Centralia, Washington. In its 2010 Regional Haze SIP, Ecology indicated that the Centralia plant significantly impacts regional haze in twelve Class I areas in Washington and Oregon.[22] The Centralia power plant was subject to BART in Washington's regional haze plan. In 2003, EPA approved requirements applicable to the Centralia units' SO2 and PM emissions as meeting BART.[23] In 2012, EPA approved a NOx BART determination in First Revised BART Order 6426 for the Centralia power plant, which included the following control requirements: an initial NOx emission limitation of 0.21 lb/MMBtu for each unit based on the installation of SNCR on both coal-fired units plus Flex Fuel followed by an optimization study and lowering of the

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[21] *Id.* at 212.
[22] WDOE, Regional Haze Plan, December 2010, at 11-13 (Table 11-11), available at https://apps.ecology.wa.gov/publications/documents/1002041.pdf.
[23] *See* 68 Fed. Reg. 34821 (June 11, 2003).

emission limits based on the study results.[24] In addition, the BART order required each of the two Centralia units to cease burning coal and be "decommissioned" by December 31, 2020 for one unit and by December 31, 2025 for the other unit, unless Ecology determined that state or federal law requires selective catalytic reduction (SCR) to be installed on either unit.[25] In 2021, EPA approved a revision to the BART requirements for the Centralia power plant.[26] Specifically, TransAlta had installed a Combustion Optimization System with Neural Network program (Neural Net) to decrease ammonia slip from the SNCR, and such Neural Net controls also help to reduce NOx emissions among other things. Ecology reduced the NOx limit applicable to one unit from to 0.18 lb/MMBtu and changed other requirements pertaining to use and monitoring of ammonia and analyzing coal sulfur and nitrogen content.[27] Ecology also eliminated the requirement in the BART Order 6426 that required that the units be "decommissioned" once they stopped burning coal, based on 2017 changes to a Memorandum of Agreement between TransAlta and the state of Washington.[28] As EPA states "[t]he 2017 MOA makes clear that TransAlta is not precluded from the possibility of retrofitting the facility to natural gas, or other non-coal energy source, as long as it meets the statutory requirements of Chapter 80.80 RCW."[29] This state statute addresses greenhouse gas emissions from baseload electric generating plants.[30]

Ecology's Technical Support Document for its 2020 BART SIP revision states that "Ecology is aware that if TransAlta repowers the units on natural gas the visibility improvements anticipated by the current BART order and state implementation plan limits would not be met. Repowering would change the emission reduction used in determining the 2028 further progress goals for the nearby Class I Areas (Mt. Rainier and Olympic National Parks, and the Goat Rocks and Alpine Lakes Wilderness Areas) under the 2021 Regional Haze State Implementation Plan." It would also change the emission reductions used in determining the 2028 reasonable progress goals for several Oregon Class I areas. In its 2010 Regional Haze SIP, Washington identified twelve Class I areas where the Centralia Power Plant had an impact greater than or equal to 0.5 deciviews (dvs). Thus, if the Centralia units repowered to natural gas, it could significantly affect the reasonable progress goals for all of those Class I areas, which are listed in Table 2.

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[24] *See* 77 Fed. Reg. 72742(12/6/2012). *See also* First Revised BART Order 6426, attached as Ex. 1.
[25] *See* 77 Fed. Reg. 72742(12/6/2012). *See also* First Revised BART Order 6426, available at Ex. 1.
[26] 86 Fed. Reg. 24502 (May 7, 2021).
[27] Ecology, Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision, July 2020, at i (attached as Ex. 2).
[28] As discussed in 86 Fed. Reg. 13256 at 13258 (Mar. 8, 2021)
[29] 86 Fed. Reg. 13258 (Mar. 8, 2021).
[30] See Chapter 80.80 RCW, available at https://app.leg.wa.gov/rcw/default.aspx?cite=80.80.

**Table 2. Washington and Oregon Class I Areas Where Ecology Modeled Significant Visibility Impacts from the Centralia Power Plant in its 2010 Regional Haze SIP**.[31]

| |
|---|
| Alpine Lakes Wilderness (WA) |
| Glacier Peak Wilderness (WA) |
| Goat Rocks Wilderness (WA) |
| Mt. Adams Wilderness (WA) |
| Mt. Hood Wilderness (OR) |
| Mt. Jefferson Wilderness (OR) |
| Mt. Rainier National Park (WA) |
| Mt. Washington Wilderness (OR) |
| North Cascades National Park (WA) |
| Olympic National Park (WA) |
| Pasayten Wilderness (WA) |
| Three Sisters Wilderness (OR) |

In its Technical Support Document for its 2020 BART SIP revision, Ecology states "[i]f TransAlta decides to switch to non-coal power generation, a Notice of Construction application would need to be submitted to Southwest Clean Air Agency by the company. Ecology would require the company to do, at a minimum, emissions modeling that would be required under the BART process to quantify the visibility impacts resulting from the operation as a natural gas boiler plant (EGU)."[32] It appears that Ecology may have been stating that it would evaluate whether the Centralia plant, powered with a fuel other than coal, would be subject to BART or subject to additional control requirements, by evaluating what the impacts of the plant would be on visibility in Class I areas. But the Centralia plant was already determined to be subject to BART.[33] Applicability to BART would not change if either or both units were repowered to natural gas or some other fuel.[34]

Ecology's draft regional haze plan for the second implementation period does not address the possibility that one or both the Centralia units could be allowed to repower with a fuel other than coal under the revised 2020 BART Order. In fact, Ecology states that the 2028 "on the books" emissions of SO2 and NOx will decrease significantly when coal-fired power production ceases at TransAlta.[35] Ecology also makes clear in its draft regional haze plan that it set Centralia's 2028 emissions to zero based on the facility ceasing coal-fired energy production by 2020 for one unit and by 2025 for the other unit.[36] Ecology identifies the cessation of coal-firing at the

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[31] 2010 Washington Regional Haze State Implementation Plan at 11-13 (Table 11-11), available at https://apps.ecology.wa.gov/publications/documents/1002041.pdf.
[32] Ecology, Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision, July 2020, at 3 (Ex. 2).
[33] 2010 Washington Regional Haze State Implementation Plan at 11-13 (Table 11-9), available at https://apps.ecology.wa.gov/publications/documents/1002041.pdf.
[34] *See*, e.g., 77 Fed. Reg. 39425 at 39429 (July 3, 2012).
[35] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 77-78.
[36] *Id.* at 82 and at 176.

Centralia units as a "shutdown schedule" control and as part of its Long Term Strategy.[37] Yet, if the Centralia units could lawfully be repowered with natural gas or another fuel, which Ecology has made clear in its 2020 Technical Support Document for its BART order revision could occur, then its assumption of zero emissions in 2028 from the Centralia Power Plant is significantly flawed. EPA has said if a state is going to rely on a source shutdown in its regional haze plan, the shutdown needs to be federally enforceable.[38] Thus, Ecology needs to make federally enforceable the decommissioning of the Centralia Generating Station's coal-fired units in its SIP and issue a revised Order, as was required in the Order prior to the 2020 revisions.

In its 2020 Technical Support Document for the 2020 BART Revision, Ecology explains some of the requirements that would apply if the Centralia units repowered to natural gas or another fuel. For example, Ecology states that under Chapter 80.80 RCW that sets greenhouse gas emission limits reflective of combined cycle combustion turbines, TransAlta would need to take an enforceable limit to keep operations annually below a 60% capacity factor to avoid being classified as a baseload power plant under Chapter 80.80 RCW which would require that the facility meet GHG emission limits.[39] Ecology ignores the possibility that the units could be repowered to a natural gas-fired combined cycle power plant by retaining the steam turbine but replacing the coal boiler with a gas-fired combustion turbine and a heat recovery steam generator, in which case it could likely meet the GHG emission limit of Chapter 80.80 RCW and thus be allowed to operate at higher capacity factors.

Ecology also states that if TransAlta decided to switch to non-coal fired power generation, they would have to submit a Notice of Construction application to the Southwest Clean Air Agency and that Ecology would "require the company to do, at a minimum, emissions modeling that would be required under the BART process to quantify the visibility impacts resulting from the operation as a natural gas boiler plant (EGU)."[40] Neither the modeling nor the requirement to obtain a construction permit would guarantee that any specified level of emissions reduction would be required if the units were repowered with another fuel such as natural gas because it depends on how applicability to emissions control requirements such as best available control technology (BACT) would be determined.

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[37] *Id.* at 212.
[38] *See* U.S. EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period, July 8, 2021, at 10 ("[O]n the way measures, including anticipated shutdowns that are relied on to forgo a four-factor analysis or shorten the remaining useful life of a source, are necessary to make reasonable progress and must be included in a SIP."). *See also*, e.g., 11/1/2021 EPA letter to Wyoming Department of Environmental Quality, Comments on Draft Wyoming State Implementation Plan Regional Haze Round Two, at 5 ("If the State is relying on the source shutdowns as part of its long-term strategy for making reasonable progress, Wyoming must make these planned retirements enforceable in the SIP. Similarly, if the State is relying on the source shutdowns to forgo conducting a four-factor analysis because a shutdown is effectively the most stringent control available, the shutdown must be in the SIP.)

[39] Ecology, Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision, July 2020, at 6-7 (Ex. 2).
[40] *Id.* at 3.

An estimate of what the NOx emissions could be assuming a conversion of the existing boilers from coal to natural gas can be made based on the following assumptions:

- Assume same generating capacity with gas of 670 MW
- Assume slightly higher hourly heat input with natural gas, based on Energy Information Administration data that shows the average heat rate of a natural gas-fired steam generation is 10,416 Btu/kW-hr as compared to the average heat rate of a coal-fired steam generator of 10,142 Btu/kW-hr[41] (meaning the heat input per hour would be 2.7% higher for natural gas firing, assuming the same generating capacity could be achieved with natural gas). Thus, assuming a coal-fired heat rate of 10,142 Btu/kW-hr, the hourly heat input to each boiler with coal would be approximately 6,795 MMBtu/hour, and the maximum hourly heat input to each boiler with natural gas would be 2.7% higher or 6,979 MMBtu/hour.

Using AP-42 emission factors and assuming that the burners would continue to be low NOx burners, the NOx emission factor for the boilers would be 140 lb per MMscf, which equates to approximately 0.14 lb/MMBtu.[42] If the units had to be limited to 60% capacity factor to avoid the GHG emission limits of Chapter 80.80 RCW, the potential NOx emissions of each Centralia unit repowered to natural gas would be 2,568 tons per year per unit or 5,135 tons per year total. In comparison, the NOx emissions from the two Centralia units per 2018-2020 averaged about 3,300 tons per year per unit or 6,600 tons per year when both units were operating. Thus, while repowering the Centralia units from coal to gas would reduce emissions from the units, it would not by any means eliminate the regional haze pollutants from the units as was required in the first planning period SIP and was assumed for the plant in the reasonable progress goals determination and in the modeling of the Long Term Strategy for this second planning period SIP.

It appears that TransAlta has been pursuing a coal-to-gas conversion program at some of its other units in Canada.[43] Thus, Ecology cannot just dismiss the possibility of repowering the Centralia units as unlikely. For these reasons, Ecology needs to specifically require the decommissioning of the Centralia Generating Station's coal-fired units to be consistent with its proposed Long Term Strategy and its determination of reasonable progress goals. Failing that, Ecology must include the expected emissions from a re-powered Centralia Power Plant in its 2028 modeling and determination of reasonable progress goals and advise nearby states of the changes in 2028 emissions from the facility so that they also revise their Class I area reasonable progress goals.

### B. Alcoa Primary Metals Intalco Works and Alcoa Wenatchee

The Alcoa Primary Metals Intalco Works Plant (Intalco Plant) is an aluminum smelter located in Ferndale, Washington. In its 2010 Regional Haze SIP, Ecology indicated that the Intalco plant

[41] *See* https://www.eia.gov/electricity/annual/html/epa_08_02.html.
[42] EPA, AP-42, table 1.4-1.
[43] https://www.nsenergybusiness.com/features/coal-gas-conversion-us-canada/.

significantly impacted regional haze in seven Class I areas in Washington.[44] NPCA has found that the Alcoa Intalco plant potentially impacts up to 42 Class I areas and that it is the most significant industrial contributor to regional haze at North Cascades National Park.[45] Ecology states that the Intalco Plant has been under curtailment since 2020.[46]

The Alcoa Wenatchee Plant is an aluminum smelter located in Wenatchee, Washington. As shown in Table 1 above, the Wenatchee plant has a Q/d value of 80.9 based on 2014 emissions. According to NPCA's analysis, emissions from the Wenatchee plant potentially impact 34 Class I areas, including the Alpine Lakes Wilderness area,[47] located approximately 28 miles west of the facility, and also North Cascades National Park to the northwest and Mount Rainier National Park to the southwest.[48] Ecology states that the Wenatchee plant has been in curtailment since 2015.[49]

Washington's 5-year regional haze progress report acknowledged that the SO2 emissions from Intalco and, to a lesser extent the Wenatchee facility, create a challenge to additional visibility improvement in North Cascades and Olympic National Park.[50] Thus, Ecology is including the Intalco plant and the Wenatchee plant as part of its Long Term Strategy for the regional haze plan for the second implementation period.[51] These plants have the third and fourth highest Q/d values based on 2014 emissions, and Ecology has acknowledged that the plants would contribute to regional haze if the plants restarted operations.[52] However, Ecology's Long Term Strategy does not specify any controls to be installed at these plants if operations resume.

Ecology has developed Agreed Orders 18100 and 18216 that require these plants to complete a four-factor analysis of controls prior to startup, if either plant decides to restart.[53] The Agreed Orders require that Alcoa submit four-factor analyses at least 180 days before restarting any of the facilities' potlines, and the analyses must be based on permitted emission limits (not the recent past years of zero to very low emissions). Compliance with any controls identified in the four-factor analyses would not be required until three years after Ecology's approval of the four-factor analyses. However, the Agreed Orders do not set any deadline for Ecology to approve the four-factor analyses, nor do they define the process that would be followed for Ecology to grant approval. The Agreed Orders also do not spell out what the public review and input process would be. Moreover, the Agreed Orders allow Alcoa or Ecology "to request a change to the

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[44] WDOE, Regional Haze Plan, December 2010, at 11-10 (Table 11-6), available at https://apps.ecology.wa.gov/publications/documents/1002041.pdf.
[45] NPCA, Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), at 3.
[46] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 82.
[47] 78 Fed. Reg. 79344, 79348-79349. (Dec. 30, 2013).
[48] NPCA, Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), at 3.
[49] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 82.
[50] WDOE, "Washington State Regional Haze 5-Year Progress Report," at 213, (Sept. 2017), https://www.regulations.gov/document?D=EPA-R10-OAR-2018-0001-0004. (Progress Report)
[51] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 212.
[52] *Id.* at 82.
[53] *Id.*

conditions" of each Order by submitting a written request to the other party.[54] Thus, these requirements of the Agreed Orders, which do not in and of themselves require implementation of any control measures, could be modified via a written request by Alcoa. These Agreed Orders cannot be considered to suffice for the four-factor analyses and control measures that Ecology states are needed in the event the plants start up again. Instead, Ecology must conduct four-factor analyses for these plants now based on permitted emission rates, so Alcoa is on notice as to the control requirements it must meet before it decides whether to restart either plant. Alternatively, Ecology should revoke the plants' operating permits and require each plant to go through major source new source review permitting before restarting operations.

Ecology states that if it conducted a four-factor analysis on the Intalco planta and the Wenatchee plant now, controls would not be cost effective because the plants have extremely low emissions due to being "in curtailment."[55] However, Ecology has not revoked either plants' permits, and Ecology states the plants could restart at any time.[56] Further, Ecology has included both plants' emissions in its 2028 emissions inventory, and both plants' emissions are reflected in the reasonable progress goals.[57] Thus, Ecology is without justification to claim that it can delay conducting a four-factor analysis and imposing control requirements because controls based on current emissions would not be cost effective. Just as EPA requires forthcoming source shutdowns to be enforceable in order for a state to take into account a shortened remaining useful life in a four-factor control analysis, states cannot take into account significantly reduced emissions to determine no controls are cost effective without making such assumptions enforceable.[58] This is particularly true for the two aluminum plants, for which Ecology states could restart at any time under their existing permits and for which Ecology claims controls would be needed to address regional haze impacts if these sources restart.

With respect to the Intalco Plant, Alcoa had previously agreed to complete a Notice of Construction application for the installation of a wet scrubber.[59] That wet scrubber was required to address the area's noncompliance with the 1-hour $SO_2$ National Ambient Air Quality Standard (NAAQS). However, according to Ecology, once Alcoa decided to curtail operations of the Intalco plant, the requirement to install a scrubber became null and void.[60]

Since the Intalco plant has curtailed operations and emissions have essentially been close to nil, the 1-hour $SO_2$ ambient air concentrations in the area have decreased considerably. The table below presents the 99$^{th}$ percentile 1-hour average $SO_2$ values from the two ambient air $SO_2$ monitors in Whatcom County: One that is located at the same address as the Intalco Plant (4050 Mountain View Road, Ferndale) and the other that is located 0.5 miles away from the Intalco

[54] *See* Section V Agreed Order Nos. 18100 and 18216 in Appendix Q of WDOE Public Review Draft, Second Regional Haze Plan, October 2021.
[55] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 177-180.
[56] *Id.*
[57] *Id.* at 82, 84-86, and 176.
[58] *See* U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 17, 20. *See also* U.S. EPA, Clarification Regarding Regional Haze Plans for the Second Implementation Period, July 8, 2021, at 12.
[59] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 179. *See also* Agreed Order 16449.
[60] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 179.

Plant (6036 Kickerville Road, Ferndale). EPA has indicated that both of these monitoring sites were established to characterize air quality around the Intalco plant.[61] For comparison, compliance with the 1-hour SO2 NAAQS of 75 parts per billion (ppb) is based on the three-year average of the 99th percentile of the daily maximum 1-hour average SO2 concentration.[62]

**Table 3. 99th Percentile 1-hour SO2 Concentrations in Whatcom County, 2017 to 2021**[63]

| Year | Monitor Location | 99th Percentile 1-hour SO2 Concentration, ppb | Observations, 1-hour |
|---|---|---|---|
| 2017 | 6036 Kickerville Road, Ferndale, WA | 70 | 7884 |
| 2018 | | 74 | 8087 |
| 2019 | | 70 | 7688 |
| 2020 | | 59 | 8133 |
| 2021 | | 2 | 4083 |
| 2017 | 4050 Mountain View Rd, Ferndale, WA | 114 | 8469 |
| 2018 | | 101 | 8542 |
| 2019 | | 105 | 8535 |
| 2020 | | 62 | 8541 |
| 2021 | | 3 | 4239 |

According to Ecology, the Intalco facility began curtailing production in April 2020. The SO2 monitors around the plant showed a dramatic decrease in hourly SO2 concentrations in 2020 and 2021, compared to the three years prior. EPA designated part of Whatcom County as nonattainment for the 1-hour SO2 NAAQS effective April 3, 2021.[64] Ecology must develop and submit a nonattainment plan to EPA by October 30, 2022, which is less than a year from now.[65] Given that the SO2 emissions from the Intalco plant also are the primary contributor to regional haze, Ecology should coordinate the development of regional haze measures and 1-hour SO2 measures.

The EPA has previously found that the cost effectiveness of a lime spray forced oxidation (LSFO) scrubber at the Intalco plant would cost $3,875/ton to $4,363/ton in a 2012 proposed rulemaking.[66] That would equate to roughly $4,530/ton at most in 2019 dollars.[67] Not only would those SO2 controls be cost effective at the Intalco Plant, but such controls would presumably be required in order for the Intalco Plant to restart since the area must demonstrate attainment with the 1-hour SO2 NAAQS as expeditiously as practicable and no later than April

[61] *See*, e.g., 85 Fed. Reg. 45146 at 45150 (Table 6) (July 27, 2020).
[62] 40 C.F.R. 50.17
[63] Data from EPA's Air Data Monitor Values Report for Whatcom County SO2 Monitors available at https://www.epa.gov/outdoor-air-quality-data/monitor-values-report.
[64] 86 Fed. Reg. 16055 at 16073 (Mar. 26, 2021); 40 C.F.R. 81.348.
[65] 86 Fed. Reg. 16055 at 16057, 16059 (Mar. 26, 2021). (Nonattainment plans are due within 18 months of the effective date of the nonattainment designation).
[66] 77 Fed. Reg. 76174 at 76191 (Dec. 26, 2012).
[67] Based on changes in the Chemical Engineering Plant Cost Indices (CEPCI).

2026 (i.e., five years after the effective date of the SO2 nonattainment designation).[68] Ecology states it generally takes two to three years for the design and installation of SO2 controls,[69] and it is commonly assumed that a 180 day shakedown period is needed after installation of a pollution control. Thus, to attain the SO2 NAAQS by April 2026, the permit to install the scrubber should be approved by no later than October 2023, which is less than one year away. Based on that timeframe, Ecology should require the submittal of a construction permit application to install an LSFO scrubber at the Intalco Plant now, so that the permit authorizing such controls can be issued no later than October 2023.

It has recently been reported that negotiations are underway to potentially restart the Intalco aluminum plant (possibly under a different owner) or to build a steel mill on the site.[70] Thus, with the possibility of aluminum plant operations resuming and the fact that an SO2 nonattainment plan is required for the Intalco plant area, Ecology has no reasonable justification to allow Alcoa to wait to submit its regional haze control analysis. If the Intalco plant resumes operation, the level of SO2 control that needs to be met is known and the most effective way to meet that level of control is the installation of an LSFO wet scrubber, based on the analysis EPA previously conducted for the BART evaluation and based on analyses that presumably was done by Alcoa and Ecology in the process of developing Agreed Order 16449.[71] Thus, Ecology should re-impose the requirement in Agreed Order 16449 for Alcoa to apply for a permit to construct a new scrubber at the Intalco Plant, which presumably was necessary for the Intalco plant to comply with the SO2 NAAQS. And Ecology should issue the permit for the new scrubber no later than October 2022.

For the Intalco Wenatchee plant, Ecology should not wait to decide what controls to require to address regional haze until Alcoa decides to restart the plant. Ecology must require the submittal of a four-factor analysis of regional haze controls now and propose appropriate controls as part of its regional haze plan that would apply should the plant restart. Alternatively, Ecology should revoke the permit for the Alcoa Wenatchee plant and require the facility to obtain a new source review permit as a new source if it decides to restart.

If Ecology is going to claim that controls at these two aluminum plants are necessary as part of its Long Term Strategy for the second implementation period, then the state's plan must include the requirements that would be imposed if either of the plants resume operation. Such evaluations of the emission reduction measures necessary to make reasonable progress is required to be included in the long term strategy pursuant to 40 C.F.R. 51.308(f)(2)(i). Further, it would also give Alcoa notice as to the control requirements it must meet before it decides whether to restart either plant which would ensure expeditious limitations emissions should either plant restart.

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[68] 86 Fed. Reg. 16055 at 16057 (Mar. 26. 2021).
[69] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 170.
[70] *See*, e.g., Gallagher, Dave, Two front-runners in reopening the Intalco facility offer jobs, cleaner operation, Bellingham Herald, October 20, 2021, available at https://www.bellinghamherald.com/news/business/article255135332.html.
[71] 77 Fed. Reg. 76174 at 76191 (Dec. 26, 2012).

## C. Ash Grove Cement Plant

The Ash Grove Cement plant is a dry process cement kiln in the Duwamish Industrial area of Seattle. The cement plant has a Q/d value based on 2014 emissions of 23.1. The plant is located only 53.8 kilometers from Alpine Lakes Wilderness Area[72] and, according to NPCA, impacts 9 Class I areas in total.[73] According to Ecology, the primary regional haze pollution from the plant come from the cement kiln and the associated clinker cooler baghouses.[74] The plant is capable of burning coal, natural gas, and tire-derived fuels.[75] The plant is equipped with a Dustex 10-module pulse jet baghouse which it installed in 2019.[76]

Ecology identifies a 5.1 pound NOx per ton of clinker on a 30-day rolling average as an emission limit for the Ash Grove cement plant that is part of its long term strategy.[77] However, Ecology has not included any evidence in its draft SIP that the 5.1 lb NOx/ton clinker emission limit is an enforceable requirement of any permit or rule, or that there is an enforceable requirement to install SNCR which Ecology also states must be installed (or perhaps is currently installed). Ecology did include in the draft SIP a 2013 Consent Decree between EPA, Ash Grove Cement Company, and other parties including Ecology and Puget Sound Clean Air Agency (PSCAA) in Appendix E of its draft regional haze SIP. That Consent Decree did not set any specific NOx emission limit or NOx control requirement for the Seattle Ash Grove cement plant, although it did set specific limits for other Ash Grove cement plants located in other states. For example, for the Ash Grove cement plants in Foreman, Arkansas and in Chanute, Kansas, the 2013 Consent Decree required installation of SNCR and imposed a NOx limit of 1.5 lb/ton of clinker, applicable on a 30-day rolling average, to be met by 12/31/2015.[78] For the Ash Grove cement plant in Seattle, the 2013 Consent Decree required Ash Grove to submit an optimization protocol in accordance with Appendix A of the Consent Decree "for the purpose of optimizing the operation of the Seattle Kiln to reduce NOx emissions to the maximum extent practicable from that Kiln."[79] The Consent Decree requires that the "Seattle Kiln NOx Emission Reduction Report shall conform to the applicable procedures set forth in Appendix A [of the Consent Decree] for the establishment of a 30-Day Rolling Average Emission Limit for NOx at the Seattle Kiln" and that Ash Grove must demonstrate compliance with that emission limit "consistent with the requirements and deadlines specified in Appendix A" of the Consent Decree.[80] While the Consent Decree outlined the process for establishing and complying with a

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[72] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 162.
[73] Based on NPCA's Regional Haze Fact Sheet for Washington, Sources of Visibility Impairing Pollution in Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[74] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 167.
[75] *Id.*
[76] *Id.* at 169.
[77] *Id.* at 212.
[78] *See* 2013 Consent Decree, *United States et al. v. Ash Grove Cement Company*, (No. 2:13-cv-02299-JTM-DJW) at 22-23 (¶¶13 and 15), in Appendix E of the Public Review Draft, Second Regional Haze Plan, October 2021.
[79] 2013 Consent Decree, *United States et al. v. Ash Grove Cement Company*, (No. 2:13-cv-02299-JTM-DJW) at 25 (¶¶21), in Appendix E of the Public Review Draft, Second Regional Haze Plan, October 2021.
[80] *Id.*

NOx emission limit with EPA and PSCAA,[81] it does not specify a specific emission limit to be complied with. Ecology has not adequately explained or provided any documents that show how the 5.1 lb/ton of clinker NOx limit has been made into an enforceable requirement[82] or that it is being complied with. It does not appear that requirements that Ecology states have been established under the 2013 Consent Decree have been incorporated into the Ash Grove operating permit yet either, as the current operating permit in place for the Ash Grove cement plant does not require the use of SNCR and does not specify a NOx emission limit of 5.1 lb/ton of clinker.[83]

While it is assumed that the 5.1 lb/ton of clinker limit is enforceable by the PSCAA and Ecology through the mechanism established under 2013 Consent Decree, for the purpose of taking credit for the NOx emission limit as part of its Long Term Strategy and Regional Haze SIP, Ecology is required to provide evidence that it has adopted any requirement of its Long Term Strategy in final form.[84] Such evidence would include the submittal of the actual regulation or document to be incorporated into the SIP as an enforceable requirement.[85] However, the Draft SIP does not cite to any documents which include the 5.1 lb/ton of clinker NOx limit at the Ash Grove Cement Plant. Any measure included in the Long Term Strategy is required to have enforceable emission limitations pursuant to 40 C.F.R. 51.308(f)(2), and Ecology thus needs to provide evidence that the 5.1 lb/ton of clinker NOx limit is an enforceable emission limit.

In its discussion of the facility-specific four factor analyses for the Ash Grove Cement Plant, Ecology states that the 2013 Consent Decree required the Seattle Ash Grove Cement Plant to optimize an SNCR system.[86] However, the Consent Decree does not specifically refer to an SNCR system at the Seattle Ash Grove plant, and the current operating permit for the Seattle Ash Grove plant does not even mention an SNCR system. Ecology acknowledges that Ash Grove submitted a permit application in 2016 for installation of an SNCR system, but a permit has not been issued yet "because of unresolved technical issues."[87] Ecology describes the main technical issue as that the "permit application requested to be operated the SNCR process on an 'as needed' basis" to achieve the 5.1 lb/ton of clinker NOx limit.[88] The facility, which has a capacity of 750,000 tons of clinker per year,[89] is currently subject to a NOx limit of 1,846 tons

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[81] *Id.* at ¶22.

[82] Appendix M of the WDOE Draft Regional Haze Plan does include an August 26, 2016 letter from EPA to Ash Grove Cement Company that approves the limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average, but it is not clear that the EPA letter is an enforceable document. Further, the EPA letter does not mention an SNCR system.

[83] Air Operating Permit No. 11339 issued to Ash Grove Cement Company, last amended June 13, 2018, available at https://pscleanair.gov/DocumentCenter/View/214/Air-Operating-Permit-PDF?bidId=.

[84] This is required by EPA's SIP submittal completeness guidelines in 40 C.F.R. Part 51, Appendix V, Sections 2.1.b and d.

[85] 40 C.F.R. Part 51, Appendix V, Section 2.1.d.

[86] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 169.

[87] *Id.* at 169.

[88] *Id.*

[89] PSCAA Statement of Basis for Ash Grove Cement Company, Air Operating Permit Administrative Amendment 4 issued 6/13/18, at 1, 47, available at https://pscleanair.gov/DocumentCenter/View/216/Statement-of-Basis-PDF?bidId=.

per 12-month period,[90] which equates to an annual limit of 4.92 lb/ton of clinker when the plant is operating at maximum capacity. Unless the Ash Grove plant is not currently complying with the 5.1 lb/ton of clinker NOx limit, it is not clear that SNCR would be required to meet the 5.1 lb/ton clinker NOx limit. Ecology must disclose the current compliance status of the Ash Grove plant with the 5.1 lb/ton limit on NOx which Ecology is claiming is part of its Long Term Strategy.

Further, Ecology has failed to provide an adequate four-factor analysis of controls for the Ash Grove Cement Plant. It appears that Ecology may be finding that SNCR is a cost effective control for the Ash Grove plant that it will require as part of its regional haze plan, but it is unclear. Ecology states "PSCAA and Ash Grove are working on resolving the technical issues in the [SNCR] application with the goal of issuing a permit for the SNCR system. This permit will form the basis for emission standards that will apply to the SNCR system. Ecology intends to supplement the RHR SIP once the permit is issued."[91] Ecology has selected the Ash Grove Cement Plant as a facility to be included in its Long Term Strategy in its regional haze plan for the second implementation period. Thus, Ecology is required to perform a four-factor analysis of controls for the facility and to establish the enforceable requirements for the facility in the context of this current regional haze SIP revision. Considering that Ash Grove has requested to operate the SNCR on an "as needed" basis to achieve the NOx limit of 5.1 lb/ton of clinker, it is clear that the 5.1 lb/ton of clinker NOx limit is not reflective of the NOx removal capabilities of SNCR at the Ash Grove Cement Kiln. As stated above, the 2013 Consent Decree required at least two cement kilns to meet a much lower 1.5 lb/ton of clinker NOx limit with SNCR and .

Rather than determine the appropriate limit with SNCR at the Ash Grove cement kiln or address other methods of reducing NOx at the plant, Ecology states that it "has determined the EPA Consent Decree limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average is adequate for reasonable progress at this time until a final permit for the SNCR system is issued by Puget Sound Clean Air Agency."[92] Ecology's approach does not meet the regional haze requirement that the emission reduction measures necessary to make reasonable progress be included in the long term strategy pursuant to 40 C.F.R. 51.308(f)(2)(i). Ecology must conduct a four-factor analysis now as part of its regional haze plan for the Ash Grove cement plant to fully evaluate all cost-effective controls and to impose an emission limit reflective of the efficacy of the control required.

Ecology briefly evaluated the top NOx control technology, SCR, for the Ash Grove plant, but discounted the control due to SCR operational problems that could occur if it was installed upstream of the baghouse (because the high particulate could foul the catalyst) or if it was installed downstream of the baghouse (because the exhaust temperature would be too low for effective operation of the SCR and require installation of a heat exchanger).[93] However, another top control that Ecology failed to evaluate is the control option of installing catalytic ceramic

[90] Air Operating Permit No. 11339, issued to Ash Grove Cement Company by PSCAA, last amended June 13, 2018, at 10, available at https://pscleanair.gov/DocumentCenter/View/214/Air-Operating-Permit-PDF?bidId=.
[91] *Id.*
[92] *Id.*
[93] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 168.

filters in the existing main baghouse at the cement kiln. Several vendors are offering catalytic ceramic filter systems for baghouses that can remove NOx through embedded catalysts in the filter, particulate matter, and SO2 with the use of dry sorbent injection, such as Tri-Mer UltraCat and Haldor Topsoe CataFlex™ catalytic filter bags that can be installed in place of or inside a standard filter bag at an existing baghouse. Such vendors claim that catalytic filters can achieve 90% or greater NOx removal.[94] Notably, the catalytic ceramic filters have been geared towards cement kilns, among other facilities, to help meet the Portland cement maximum achievable control technology (MACT) standards.[95]

Recently, a cost assessment for the use of a ceramic catalytic filtration system was done for the GCC Pueblo Cement Plant in Colorado.[96] That information can be used to estimate the costs of using a catalytic ceramic filtration system at the Ash Grove plant. The GCC plant is somewhat similar to the Ash Grove Seattle plant in that both cement kilns use the dry kiln process and use a preheater and precalciner.[97] The GCC Pueblo Plant has a higher cement production rate at 3,750 tons/day compared to 2,200 tons per day at the Seattle Ash Grove cement plant.[98] Thus, the cost estimate of the use of a ceramic catalytic filtration system would be higher than the costs of such a system at the Ash Grove plant in Seattle.

There are a few options for using a ceramic catalytic filtration system at the Ash Grove Plant: 1) install a stand-alone catalytic ceramic filtration system that would be used after the existing baghouse, 2) replace an existing baghouse with a stand-alone catalytic ceramic filter system, and 3) install catalytic filter bags within the existing baghouse. Given that a new baghouse was recently installed at the Ash Grove plant, the third option would be the most cost effective option.

Tri-Mer provided a cost estimate to replace the existing bags of the baghouse at the GCC Pueblo cement plant with catalytic ceramic filter elements. As discussed in the attached report on GCC Pueblo, Tri-Mer's costs take into account the addition of an ammonia injection system and that the exhaust flue gas of the cement kiln would no longer need to be cooled to a temperature required by the existing fabric filter bags.[99] Tri-Mer determined that the cost for a bag-to-ceramic filter retrofit would cost $800/ton of NOx removed at the GCC Pueblo Plant and would reduce NOx by 90%, as well as continuing to remove PM10 and PM2.5 at very high efficiencies (greater than 99.9%).[100] Tri-Mer's cost effectiveness value reflects a capital cost of $8,999,200

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[94] *See*, e.g., https://tri-mer.com/hot-gas-treatment/hot-gas-filtration.html. *See also* Exhibit 3, Haldor Topsoe CataFlex™ brochure; and GEA BisCat – Ceramic catalyst filter information available at https://www.gea.com/en/news/trade-press/2019/biscat-ceramic-catalyst-filter.jsp.
[95] *See* Air & Waste Management Association, The Magazine for Environmental Managers, Sponsored Content, "Catalytic Filter Technology Provides Important Flexibility for Controlling PM, NOx, SOx, O-HAPS," October 2018, attached as Ex. 4 and available at https://pubs.awma.org/flip/EM-Oct-2018/sponsoredcontent_trimer.pdf.
[96] Klafka, Steve, Wingra Engineering, GCC Rio Grande – Pueblo Cement Plant, Four-Factor Reasonable Progress Analysis, September 23, 2021, hereinafter GCC Pueblo Four Factor Analysis, attached as Ex. 5.
[97] *See* GCC Pueblo Four Factor Analysis, Appendix B at 2 (Ex. 5); *see also* PSCAA Statement of Basis for Ash Grove Cement Company, Air Operating Permit Administrative Amendment 4 issued 6/13/18 at 3 (Ex. 6).
[98] *See* GCC Pueblo Four Factor Analysis, Appendix B at 2; *see also* PSCAA Statement of Basis for Ash Grove Cement Company Air Operating Permit at 1.
[99] GCC Pueblo Four Factor Analysis at 12.
[100] *Id.,* Appendix F at 5-6.

for bag replacement with catalytic ceramic filters and an annual operating expense cost for the control system of $1,620,000/year.[101] The annual operating costs take into account power costs, use of aqueous ammonia (19% by weight), maintenance, and replacement of the filters every 10 years.[102] The use of aqueous ammonia is safer than using anhydrous ammonia, and there is not a federal requirement for an accidental release plan.

Tri-Mer states that some of the added benefits of using a ceramic catalytic filtration system for control of NOx, as well as particulate, include that there is minimal catalyst plugging, reduced ammonia slip (well below 10 parts per million), and negligible catalyst deactivation.[103] Tri-Mer states that "a ceramic filter has no deactivation of the catalyst in a continuous operation for 10 years+."[104] In addition, with the use of sorbent injection, the catalytic ceramic filtration system could also be used to reduce SO2 emissions by 90% or more.[105]

The Seattle Ash Grove Cement facility had NOx emissions of 1,144 tons per year in 2014,[106] thus a 90% reduction would equate to 1,030 tons per year of NOx reduced from 2014 levels. Based on the allowable NOx emission rate of 1,846 tons per 12-month period and the annual capacity of the Ash Grove plant of 750,000 tons of clinker production, the use of catalytic ceramic baghouse filters would allow for a NOx emission limit of approximately 0.5 lb/ton of clinker.[107] This is significantly lower than the 5.1 lb/ton clinker NOx limit that Ecology is proposing to be part of the state's Long Term Strategy. Thus, Ecology must fully evaluate the use of catalytic ceramic filter bags at the Ash Grove cement plant as a top regional haze control.

SNCR should be considered a second tier control compared to catalytic ceramic baghouse filters. However, SNCR can most assuredly reduce NOx to lower emission rates than the 5.1 lb/ton of clinker emission rate that Ash Grove is apparently negotiating with PSCAA for its SNCR system.[108] There are several cement kilns with SNCR with lower NOx limits than 5.1 lb/ton of clinker. Indeed, the 2013 Consent Decree requires a NOx limit of 1.5 lb/ton of clinker, applicable on a 30-day rolling average, to be met by 12/31/2015 at several cement kilns.[109] In any evaluation of SNCR as a regional haze control for the Seattle Ash Grove plant, Ecology must evaluate the maximum emission reduction capabilities of the control and not simply allow

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[101] *Id.*, Appendix F at 6. Note that the annual operating expense was calculated by subtracting the estimated Capital Investment of $8,999,200 from estimated lifetime cost (Capital expense plus 20 years of operating expenses) of $41,399,200 provided for the GCC Pueblo plant by Tri-Mer.
[102] *Id.*, Appendix F at 6.
[103] *Id.,* Appendix F at 7.
[104] *Id.*
[105] *Id.,* Appendix F at 5.
[106] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 84.
[107] *See* PSCAA Statement of Basis for Ash Grove Cement Company, Air Operating Permit Administrative Amendment 4 issued 6/13/18, at 1 (Ex. 6); and Air Operating Permit No. 11339, issued to Ash Grove Cement Company by PSCAA, last amended June 13, 2018, at 10 (Ex. 7). Assuming 90% NOx control from the 1,846 tons NOx per 12-month period limit equates to 0.5 lb/ton of clinker at maximum production capacity of 750,000 tons of clinker per year.
[108] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 168.
[109] *See* 2013 Consent Decree, *United States et al. v. Ash Grove Cement Company*, (No. 2:13-cv-02299-JTM-DJW) at 22-23 (¶¶13, 15, 25, 30), in Appendix E of the Public Review Draft, Second Regional Haze Plan, October 2021.

periodic implementation of an SNCR system at the Ash Grove cement plant to meet an unreasonably high NOx emission limit.

With respect to SO2 emissions from the Ash Grove Plant, Ecology states the following about the cement plant:

> SO2 emissions at the plant come from burning sulfur containing fuels. The plant is capable of burning coal, natural gas, and tire-derived fuels. The plant has not been using coal for the last couple of years, but still has the ability to use it. As the facility can still use coal, SO2 emissions from the 2014 EI (with coal combustion) were included in the modeling to determine progress. The alkaline cement clinker removes some SO2 from the combustion gases. The facility uses this as a primary method of SO2 control.

WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 167.

If the plant has not been using coal in the past couple of years then, assuming that fuel change has reduced SO2 emissions, an emission control requirement of at least no longer burning coal at the Seattle Ash Grove plant should be imposed as a minimum regional haze control for SO2 emissions from the cement plant. However, the use of catalytic ceramic filter with sorbent injection should also be evaluated as an available SO2 control for the cement plant.

In summary, if Ecology is going to include the Ash Grove cement plant as part of its Long Term Strategy, the state's plan must evaluate controls for the facility in a four-factor analysis and impose appropriate emission limits and control requirements. Ecology admits that the 5.1 lb/ton of clinker emission rate is not reflective of even full-time operation of an SNCR system, and yet it is proposing a 5.1 lb/ton NOx limit that purportedly requires SNCR for the facility in its Long Term Strategy with a plan to revise the regional haze plan once a permit for the SNCR system is issued by PSCAA. Ecology has not even provided evidence that the 5.1 lb/ton clinker NOx limit has been adopted in a final enforceable form such that it can be incorporated into the federally enforceable SIP. Ecology's approach does not meet the regional haze requirement that the emission reduction measures necessary to make reasonable progress be included in the long term strategy pursuant to 40 C.F.R. 51.308(f)(2)(i). Ecology must conduct a four-factor analysis now as part of its regional haze plan for the Ash Grove cement plant to fully evaluate all cost-effective controls and to impose an emission limit reflective of the efficacy of the control required.

### D. Cardinal FG Winlock Glass Plant

The Cardinal FG Winlock plant is a flat glass manufacturing plant in Winlock, WA. According to Ecology, its 2014 NOx emissions were 791 tons per year based on 2014 emissions.[110] Thus, the facility is a large source of NOx. Ecology calculated a Q/d value for this facility of 10.7,

[110] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 84.

which exceeded its threshold of 10 that it used to select sources for four-factor analyses of controls.[111] Therefore, the Cardinal Glass Plant is subject to the four-factor analysis.

Ecology did not request a four-factor analysis of pollution controls for the Cardinal Glass Plant. Instead, Ecology proposes to rely on the fact that the company recently submitted a permit application to install SCR controls, which it proposed concurrently with an increase in glass production capacity from 650 tons per day to 750 tons per day.[112] According to Ecology, the company is also requesting a much lower facility-wide NOx limit of 249.62 tons per year, which apparently is 583.05 tons per year lower than the facility's current emission limits.[113] According to Ecology, to ensure kiln exhaust gas temperatures are high enough for the successful operation of the SCR, the existing spray dryer and electrostatic precipitator (ESP) will have to operate at higher temperatures which will increase emissions of SO2, PM10, and PM2.5.[114] It also appears that the company is requesting lower NOx limits, as well as lower carbon monoxide limits, to allow the Cardinal Glass Plant to be considered a minor source (i.e., under 250 tons per year), so that the emission increases of SO2 and PM2.5 due not trigger prevention of significant permitting requirements as a major modification.

Ecology is relying on the Cardinal's plans to install SCR as part of its Long Term Strategy. Ecology has included a copy of SWCAA's Air Discharge Permit 20-3409, issued February 11, 2021, in Appendix H of its SIP and presumably will be including that permit as the enforceable requirement to incorporate into its regional haze SIP.

However, the issuance of the permit for the SCR and increase in capacity does not negate the need for Ecology to conduct its own four-factor analysis of controls and, particularly in this case, to establish appropriate emission limits as is required to be included in the Long Term Strategy pursuant to 40 C.F.R. 51.308(f)(2).

With respect to NOx, the facility-wide NOx emissions in 2014 were 791 tons per year, and the facility-wide potential to emit is 249.62 tons per year,[115] which only reflects a NOx reduction with SCR of 68%. That is much lower than the 90%+ control efficiency that SCR is capable of achieving. In addition, the prior permit for the Cardinal FG Winlock Glass Plant required use of the 3R Process for control of NOx emissions,[116] and it appears that process is no longer required in the 2021 permit. The Pilkington 3R Process is described as using "various hydrocarbon fuels, injected into the furnace waste gas stream, as the agent to reduce NOx to harmless nitrogen and water vapor."[117] If the company were required to add SCR along with using the existing 3R Process, it could achieve lower NOx emission rates. Ecology must explain why it is justifiable

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[111] *Id.* at 160 and 162.
[112] *Id.* at 171.
[113] *Id.* at 172.
[114] *Id.*
[115] *Id.*
[116] SWCAA Air Discharge Permit 04-2568R2, 12/16/2008, at 4, available at https://www.swcleanair.gov/docs/permits/TitleV/SW08-14-R1AOP.pdf and attached as Ex. 8.
[117] State of New Jersey, Department of Environmental Protection, State of the Art (SOTA) Manual for the Glass Industry, July 1997, at 3.15-22, available at https://p2infohouse.org/ref/14/13344.pdf.

for Cardinal FG Winlock to stop using the 3R Process to control NOx, when it could readily use additional NOx controls in addition to the 3R Process.

In addition, the use of low temperature catalysts should have been evaluated for the SCR, to avoid having to reheat the gas stream which will reduce the effectiveness of the PM and SO2 controls. Such low temperature catalysts would reduce if not eliminate the projected increases in SO2 and particulate matter with the SCR, which are claimed to be due to the need to achieve a higher temperature in the flue gas due to the SCR.

Another option Ecology should consider for the Cardinal Glass Plant is the use of ceramic catalyst filters along with the existing 3R process, which can reduce NOx at lower temperatures than conventional SCR and also capture particulate and SO2. This control method is discussed above in Section II.C above on the Ash Grove Cement Plant and it is also discussed in the January 27, 2021 Four-Factor Reasonable Progress Analysis for the Ardagh Glass plant in Seattle, Washington, done by Wingra Engineering, S.C. and attached as Exhibit 10.

Ecology states that RCS 70A.15.2220 "requires that when a source decides to modify or replace an existing emission control system, Ecology or the local air pollution control authority must assure that the modified ore replacement control system meets a reasonably available control technology (RACT) level of emissions control at a minimum."[118] RACT is defined under Washington State law as:

> *[T]he lowest emission limit* that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls. RACT requirements for a source or source category shall be adopted only after notice and opportunity for comment are afforded.

RWA 70A.15.1030(20) (emphasis added).

While SCR is a control technology capable of meeting the lowest emission limit, the proposed NOx emission limit does not appear to require the "lowest emission limit" that can be met with SCR. Further, with the decreases in SO2 and PM removal efficacy that will occur as a result of the SCR installation, it is questionable whether the SO2 and PM emission limits reflect RACT because the revised SO2 and PM emission limits do not reflect the lowest emission limit for the spray dryer and electrostatic precipitator that are installed at the glass furnace. Ecology must comply with the state law RCW 70A.15.2220 cited in its draft Long-Term Strategy as part of its review and determination of appropriate regional haze emission limitations for the Cardinal FG Winlock glass plant in its Regional Haze plan for the second implementation period. It has an obligation to ensure RACT level controls are met.

[118] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 215.

The regional haze four-factor analysis applies to the Cardinal Glass Plant *in conjunction with* any other Clean Air Act requirements. The fact that the Cardinal Glass Plant has received a permit requiring the installation of SCR does not obviate the need for the state to comply with reasonable progress requirements The emission limits of the permit, as described in the draft regional haze SIP, do not reflect the maximum capabilities of SCR, including the ability to use low temperature catalyst to avoid or eliminate the SO2 and particulate matter increases that were projected to occur with SCR. Ecology must conduct its own four-factor analysis of regional haze controls and impose emission limits that reflect the controls it determines are necessary to make reasonable progress towards the national visibility goal.

## III. Review and Comments on Other Sources Selected by Ecology for Review That Were Unjustifiably Deferred from Ecology's Proposed Long Term Strategy

As previously stated, Ecology used a Q/d analysis and selected a Q/d value of 10 or higher as a threshold for selecting sources to require a four-factor analysis of regional haze controls.[119] Ecology required four-factor analyses for five petroleum refineries and seven pulp and paper mills.[120] Ecology then selected the refineries as the first priority of sources to focus on for regional haze controls. Ecology prioritized pulp and paper mills lower than refineries because they "are not located as close to each other as the refineries so they do not have as great of a cumulative effect."[121] Ecology also states that the potential reduction in regional haze emissions from pulp and paper mills is "vastly less than the potential refinery emission reductions."[122]

Ecology states that it must follow its RACT rule requirements before it can legally establish control requirements.[123] However, Ecology has not conducted a RACT evaluation in this regional haze plan. Yet, the regional haze plan for the second implementation period is required to evaluate controls for selected sources and determine through a four-factor analysis what control measures are necessary to make reasonable progress towards the national visibility goal.[124] For a source that is found subject to the required reasonable progress four-factor analysis as a result of a state's reasonable progress screening process, the state must ensure the analysis is conducted as part of its regional haze plan. Neither the Act nor EPA's rules provide an "off-ramp" for a source in this situation. Ecology's Public Review Draft is stated to be its State Implementation Plan (SIP) revision for the second regional haze plan implementation period of

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[119] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 160.
[120] These company four-factor analyses are provided at [https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/RegionalHaze.htm](https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/RegionalHaze.htm).
[121] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 166.
[122] *Id.* at 167.
[123] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 163.
[124] *See* U.S. EPA, Guidance on Regional Haze Plans for the Second Implementation Period, August 20, 2019, at 28 (Step 4).

2018 to 2028, and thus it is assumed for the purpose of these comments that the Public Review Draft is the plan to be submitted to EPA for approval.

Comments are provided herein on the four-factor analyses and Ecology's analysis of controls for the five refineries and the seven pulp and paper mills.

## A. Four-Factor Analyses for the Oil Refineries

Ecology states in its draft regional haze plan that the refineries in Washington "are over 40 years old and the facilities have maintained the majority of the equipment in a manner that has not required updating emission controls to current standards."[125] Ecology did a nationwide comparison of 2014 facility-wide NOx emissions per barrel of production capacity for the five Washington refineries to 83 other refineries located in the U.S. and found that "Washington refineries represent four of the top five facilities in the nine states in terms of NOx emissions per 1,000 barrels produced per day."[126]

Ecology requested four-factor analyses from the five Washington refineries to address each fluid catalytic cracking unit (FCCU), each boiler with heat input greater than 40 MMBtu/hr, and each heater with heat input greater than 40 MMBtu/hr that has not been retrofitted with NOx controls since 2005.[127] None of the five refineries for which Ecology requested four-factor analyses found that low NOx burners or ultra low NOx burners (LNB/ULNB) or SCR were appropriate for regional haze reasonable progress controls. Either the companies claimed that a control, such as ULNB, was not technically feasible for a heater or boiler, or a company claimed that controls were not cost effective. Ecology conducted its own cost effectiveness analyses for the application of SCR to the refinery heaters and boilers. Ecology states that two refineries did not submit analyses for their FCCUs, and Ecology subsequently decided to evaluate SCR for those FCCUs "since they are a large source of NOx emissions."[128]

### 1. Comments on Ecology's Determination of Cost Effective Controls for the Petroleum Refineries

Ecology conducted SCR cost effectiveness analyses for several emissions units at the refineries using EPA's SCR cost calculation spreadsheet made available with its Control Cost Manual.[129] Ecology states in its discussion of the four-factor analyses of controls for the units at each refinery that it found SCR would be cost effective for the FCC units and for various heaters and boilers.[130] Ecology's draft SIP identifies a $6,300/ton reasonableness threshold for NOx controls

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[125] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 184.
[126] *Id.* at 185-186 (Table 7-6).
[127] *See*, e.g., BP Cherry Point Refinery Regional Haze Four Factor Analysis, April 2020 (hereinafter "BP Cherry Point Analysis") at 2, available at https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/RegionalHaze.htm.
[128] *Id.* at 187.
[129] *Id.* at 187.
[130] *Id.*

in its discussion of controls for the pulp and paper industry.[131] It appears, but is not entirely clear, that Ecology is using a similar reasonableness threshold for NOx controls at the refineries. For any cost threshold selected by a state, EPA's regional haze guidance requires that the State Implementation Plan (SIP) "explain why the selected threshold is appropriate for that purpose and consistent with the requirements to make reasonable progress."[132] It must be noted that other states have adopted higher cost effectiveness reasonableness thresholds. For example, Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton.[133] Colorado is also using a reasonableness cost threshold of $10,000/ton.[134] New Mexico is using a reasonableness cost effectiveness threshold of $7,000/ton.[135]

With respect to determining whether a NOx control is cost effective for a particular heater or boiler at a refinery, it is important to consider the costs that similar sources have had to bear to meet Clean Air Act requirements for NOx. For example, several Californian Air Districts as well as the states of Texas, Massachusetts, New York, and Georgia have set NOx emission limits for existing heaters and boilers that are reflective of the use of LNB/ULNB, SNCR, or SCR.[136] While these emission limits were often set to address ozone and/or PM2.5 nonattainment issues, the fact is that each of these controls can be quite cost effective. For example, a San Joaquin Valley Air Pollution Control District (SJVAPCD) cost analysis for ULNBs shows that the retrofitting of such controls to meet a NOx limit of 6 ppm would have cost effectiveness values ranging from $545/ton to $3,270/ton, with the higher cost effectiveness values being at smaller units (the smallest size unit evaluated was 30 MMBtu/hr) and/or lower capacity factors.[137] In addition, based on a SJVAPCD cost analysis for SCR to meet NOx emission rates of 2.5 ppm, SCR was found to have a cost effectiveness of $1,025/ton to $6,149/ton for heaters and boilers as small as 30 MMBtu/hr, with the lowest cost effectiveness values for the larger units and units that operate at higher capacity factors.[138]

We encourage Ecology to review Table 42 of the attached March 6, 2020 report of four-factor analyses for the oil and gas industry,[139] which includes a list of state and local air agency emission limits and rules applicable to existing natural gas-fired heaters and boilers. As that report indicates, the most stringent NOx limit for units greater than or equal to 75 MMBtu/hour required of existing sources in the listed state and local rules is 5 ppm, which most likely reflects

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[131] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 182.
[132] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 39.
[133] *See* Oregon Regional Haze State Implementation Plan for the Period 2018-2028, Aug. 27, 2021 Public Notice Draft, at 35, 45.
[134] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, available at https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v.
[135] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.
[136] Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 139-145, attached as Ex. 10.
[137] *Id.* at 125 (Table 36).
[138] *Id.* at 135 (Table 41).
[139] Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 139-145, attached as Ex. 10.

use of SCR. There are several examples of similar sources having to bear the costs of these controls to meet Clean Air Act requirements. Ecology would thus be justified in finding SCR for the heaters, boilers and FCCUs that it evaluated in its draft regional haze plan as cost effective.

Although Ecology states that SCR would be cost effective for several refinery emission units, Ecology also states it "will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates."[140] Presumably, Ecology states this because the Western States Petroleum Association (WSPA) has apparently contended that Ecology did not use the EPA SCR cost spreadsheet appropriately and that Ecology's application of the EPA's SCR cost spreadsheet is not appropriate for refineries.[141] However, as Ecology stated in its draft regional haze plan, the Washington refineries generally did not adequately document the basis for their SCR cost assessments. Ecology chose to use EPA's SCR cost spreadsheet which is based on the SCR chapter of the Control Cost Manual and which, in turn, has been very well documented and which also went through public notice and comment.

The EPA's SCR cost calculation spreadsheet was based on cost algorithms for utility boilers, but that fact does not make the SCR cost algorithms not applicable to other types of emission units such as those at refineries. Several of the refinery emission units that Ecology evaluated for SCR are boilers and process heaters. The emissions characteristics from those sources are similar or identical to the emission characteristics from boilers. In fact, EPA's AP-42 emission factors for petroleum refining refer to its emission factors for boilers (i.e., Section 1.3 "Fuel Oil Combustion" or Section 1.4 "Natural Gas Combustion") for determining emissions from boilers and process heaters used in the petroleum refining industry.[142]

The SCR cost spreadsheet algorithms were developed based on its Integrated Planning Model (IPM) version 6. The SCR cost documentation for the IPM written by Sargent & Lundy was in turn based on a wealth of design and cost information, including from the "Analysis of the [Midwest Ozone Group (MOG)] and [Lake Michigan Air Directors Consortium (Ladco) FGD and SCR Capacity and Cost Assumptions in the Evaluation of the Proposed EGU 1 and EGU 2 Emission Controls" and the J.E. Cichanowicz study "Current Capital Costs and Cost-effectiveness of Power Plant Emissions Control Technologies," as well as Sargent & Lundy's in-house database of recent SCR projects.[143] The costs generally reflect hot side, high dust SCRs, which also likely reflects the type of SCR that would be employed at refinery emission units including FCCUs.[144] While the cost algorithms are identified as providing the "average" costs with the "average" project,[145] the algorithms are also based on a significant amount of SCR

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[140] *Id.*
[141] *Id.* at 188, 192, and 194.
[142] *See* U.S. EPA, AP-42, Chapter 5.1, Table 5.5-1, available at https://www.epa.gov/sites/default/files/2020-09/documents/5.1_petroleum_refining.pdf. *See also* EPA, AP-42, Chapter 1 External Combustion Sources, Sections 1.3 and 1.4, available at https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.
[143] *See* Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, Final, January 2017, prepared by Sargent & Lundy, at 1, available at https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf.
[144] *Id.*
[145] *Id.*

installation and SCR retrofit data from the industry where such controls are probably the most widely used (i.e., the fossil fuel-fired electric utility industry).

EPA's August 20, 2019 regional haze guidance refers to its cost spreadsheets developed as part of its recommendation that states follow the EPA's Control Cost Manual "to facilitate apples-to-apples comparisons of different controls options for the same source, and comparisons across different sources."[146] EPA does not require vendor-generated cost assessments for making regional haze control decisions.[147] EPA also cautions against relying solely on vendor cost estimates that are not sufficiently documented and without verifying that the vendor followed the costing principles of the EPA's Control Cost Manual.[148] The Washington refineries relied on the EPA SCR cost calculation spreadsheet for SCR cost analyses for at least some refinery emission units, although the refineries did not generally document its decisions to use higher retrofit factors or higher costs for items such as ammonia reagent as is discussed further below.[149] Thus, Ecology should not discount its cost effectiveness analyses of SCR for refinery emission units as not sufficiently accurate to determine that SCR is cost effective for an emission unit at a refinery.

SCR systems have been retrofit to many refinery emission units over the years, including at fluid catalytic cracking units (FCCUs). A paper from 2002 discusses the success of SCR retrofit at an FCCU at the BP Whiting Refinery and refers to SCR installations at FCCUs dating back to 1986.[150] SCR has also been used on refinery boilers and heaters, including at some Washington refineries,[151] and can achieve in excess of 95% NOx control from the NOx emitted from the heaters.[152] Experience using SCRs in the refinery industry shows the controls are reliable and have low operational and maintenance costs.[153]

For all of these reasons, Ecology is justified to use the EPA SCR cost spreadsheet to determine cost effectiveness of SCR at the heaters, boilers and FCCUs for the five refineries it evaluated for controls for its regional haze plan.

In its draft regional haze plan, Ecology identified the emission units listed in Table 4 for which SCR would be a cost effective regional haze control. The cost effective controls identified by

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146 *See* U.S. EPA, Guidance on Regional Haze Plans for the Second Implementation Period, August 20, 2019, at 31.
147 *Id.* at 32.
148 *Id.*
149 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P at P-173 to P-194 (Shell Four-Factor Analysis), P-229 to P-283 (Tesoro Four-Factor Analysis), and P-334 to P-336 (U.S. Oil Four-Factor Analysis).
150 *See* Bouziden, Gerald, K. Gentile and R.G. Kunz, Selective Catalytic Reduction of NOx from Fluid Catalytic Cracking Case Study: BP Whiting Refinery, National Environmental & Safety Conference, April 23-24, 2002, New Orleans, LA, at 1, available at https://www.cormetech.com/wp-content/uploads/2018/05/env-03-128-kunz-0-Whiting-Refinery-FCC.pdf.
151 For example, BP Cherry Point has installed SCR on its #2 hydrogen plant SMR furnace, its #6 and #7 boilers, according to its August 26, 2014 Air Operating Permit #015R1M1 on the Northwest Clean Air Agency's (NWCAA's) website at https://nwcleanairwa.gov/?wpdmdl=981.
152 *See*, e.g., Jensen-Holm, Hans et al., Haldor-Topsoe, Combating NOx from refinery sources using SCR, available at http://www.topsoe.com/sites/default/files/combating_nox_from_refinery_sources_using_scr.ashx_.pdf; LaPlante, Marie P. et al., How Low Can You Go? Catalytic NOx Reduction in Refineries, available at http://nawabi.de/project/hrsg/Topsoe.pdf.
153 *Id.*

Ecology and listed in Table 4 below would reduce NOx emissions from the refineries by a total of 3,803 tons per year (based on Ecology's assumed NOx emissions reduced with SCR), reflecting a 64.5% reduction in the total 2014 annual NOx emissions from the five refineries

**Table 4. Ecology's Identification of Cost Effective SCR Determinations at the Petroleum Refineries**[154]

| Plant | Emission Unit | Cost Effectiveness, $/ton | NOx Reduced, tons per year |
|---|---|---|---|
| BP Cherry Point | #1 Reformer Heaters | $3,101/ton | 304 tpy |
| | Crude Heater | $2,051/ton | 393 tpy |
| | Reforming furnace #1 (N H2 Plant) | $6,161/ton | 262 tpy |
| | Reforming furnace #2 (S H2 Plant) | | |
| Phillips 66 Ferndale | Crude Heater 1F-1 | $2,640/ton | 166 tpy |
| | FCCU/CO Boiler/Wet Gas Scrubber 4F-101 | $3,954/ton | 247 tpy |
| Shell Puget Sound | Boiler #1 Erie City – 31G-F1 | $2,441/ton | 179 tpy |
| | FCCU Regenerator Unit | $1,948/ton | 521 tpy |
| | CRU #2 HTR, INTERHTR—10H-101, 102, 103 | $6,346/ton | 69 tpy |
| Marathon Petroleum Company (Tesoro) Anacortes Refinery | FCCU | $1,159/ton | 843.3 tpy |
| | F 102 Crude Heater | $2,962/ton | 147.6 tpy |
| | F 201 Vacuum Flasher Heater | $7,589/ton | 57.6 tpy |
| | F 6650 CAT Reformer Heater | $3,736/ton | 117 tpy |
| | F 6651 CAT Reformer Heater | $3,520/ton | 124.2 tpy |
| | F 751 Main Boiler | $2,159/ton | 202.5 tpy |
| | F 752 Main Boiler | $2,570/ton | 170.1 tpy |

Ecology evaluated SCR to achieve 90% NOx removal and assumed a 3.25% interest rate and a 25-year life in amortizing capital costs of control. Ecology's assumptions are defensible. EPA's Control Cost Manual states that, while in theory, SCR can achieve close to 100% NOx removal,

[154] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, at 188 (finding SCR at BP Cherry Point units was cost effective), at 192 (finding SCR at Phillips 66 units was cost effective), at 194 (finding SCR at Shell units was cost effective), and at 198 (fining SCR at Marathon Petroleum Company (Tesoro) units was cost effective). Appendix J at J-1.

in practice, SCRs are routinely designed to achieve 90% or greater NOx removal.[155] Ecology's use of a 3.25% interest rate is justified, as the Federal Reserve Prime Rate has been at 3.25% since March 2020.[156] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[157] A 25-year life of an SCR system is also justifiable as discussed in EPA's Control Cost Manual,[158] as long as the remaining useful life of the emission unit in question is not restricted to a shorter time period. None of the refineries indicated a restricted remaining useful life of any of the above units in the company four-factor analyses.

For those refinery units for which SCR was not determined to be cost effective, Ecology should evaluate SNCR as a NOx control. The McIlvaine Company indicates that urea-based SNCR used at refinery process units and boilers has generally achieved 50-70% NOx reduction.[159]

In addition, Ecology should not limit evaluation of LNB/ULNBs for units greater than 40 MMBtu/hour capacity, as such burners are available for smaller units.[160] The California Air Resources Board (CARB) determined as far back as 1991 that heaters and boilers as small as 5 MMBtu/hour or greater could meet NOx "best available retrofit control technology" (BARCT) limits of 30 ppmv (or about 0.036 lb/MMBtu).[161] However, more recently, California's South Coast Air Quality Management District (AQMD) concluded that even lower NOx limits, as low as 9 ppm, could be met with ULNB at boilers and process heaters as small as 2 MMBtu/hr.[162] This was based on actual ULNB retrofit experience at boilers and heaters in the San Joaquin Unified Air Pollution Control District (SJVAPCD).[163] The Ventura County Air Pollution Control District in California also found that boilers and process heaters as small as 2 MMBtu/hr could meet NOx limits of 9 ppm with ULNB.[164] Thus, Ecology should not limit the evaluation of reasonable progress controls to only heaters and boilers greater than 40 MMBtu/hr.

For companies demonstrating that the retrofit of ULNBs is not technically feasible and for which SNCR or SCR are truly not cost effective, Ecology should evaluate the costs of replacing an existing boiler or heater with a new unit equipped with state-of-the-art ULNBs. If a unit is near the end of its useful life, this could be a very cost effective and readily implementable approach to reducing NOx emissions.

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[155] *See* U.S. EPA, Control Cost Manual, Section 4, Chapter 2, at pdf page 5, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[156] https://fred.stlouisfed.org/series/DPRIME.
[157] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[158] *See* U.S. EPA, Control Cost Manual, Section 4, Chapter 2, at pdf page 80, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[159] *See* http://www.mcilvainecompany.com/industryforecast/refineries/background1/text/Chapter%20X/Chapter%20X.htm.
[160] *See*, e.g., BP Cherry Point Refinery Regional Haze Four Factor Analysis, April 2020, in Appendix P of Public Review Draft Regional Haze Plan, October 2021, at P-3.
[161] As discussed in Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020 at 120 (attached as Ex. 10).
[162] *Id.* at 121.
[163] *Id.*
[164] *Id.* at 121-122.

For those units listed in Table 4 above that Ecology found SCR to be a cost effective control, Ecology should adopt requirements for the companies to install SCR as part of its current regional haze action. Ecology has shown that SCR is cost effective for those units, and Ecology's review of the other three factors do not provide a reason to exclude any of the emission units in Table 4 above from requirement to install SCR requirement to achieve reasonable progress towards the national visibility goal.

Instead of adopting SCR control requirements for the emission units listed in Table 4 above, Ecology states that it will conduct a more extensive cost evaluation of SCR. Yet, the cost algorithms of the EPA SCR cost spreadsheet are already based on numerous SCR cost evaluations. Further, Ecology already requested four-factor analyses of potential regional haze controls from the refineries include for SCR, and Ecology determined that the company analyses were not well documented or justified.[165] In most cases, the cost analyses submitted by the refineries overstate costs and understate emissions reductions, and so the cost effectiveness numbers should not be relied upon by Ecology. In the sections that follow, more specific concerns with each company's four-factor analyses of NOx controls are provided along with a discussion of the four-factor analyses provided by Ecology in its current draft regional haze plan.

### 2. BP Cherry Point Refinery

Ecology calculated a Q/d value for the BP Cherry Point facility of 36.4, and it is ranked 5th highest Q/d on Ecology's list of sources it evaluated.[166] NPCA data shows that the facility impacts regional haze at 14 Class I areas.[167] BP Cherry Point submitted a four-factor analysis for nine emission units at the refinery:

- Crude Charge Heater;
- South Vacuum Heater;
- #1 Reformer Heaters;
- #2 Reformer Heaters;
- Naphtha HDS Charger Heater;
- Naphtha HDS Stripper Reboiler;
- Hydrocracker R-4 Heater;
- #1 Hydrogen Plant (North and South Furnaces);
- #5 Boiler.

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[165] *Id.* at 190, 192, 195, 196, 199, and 202 (Ecology stating that the various refinery companies provided limited supporting data for their cost analyses).
[166] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
[167] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.

BP states that Ecology narrowed the request to only LNB/ ULNB and SCR. BP analyzed the cost effectiveness of LNB/ULNB and SCR for these units and found that no controls were cost-effective. The following provides comments on BP's cost effectiveness analyses in its Four-Factor submittal.

*Issues with Four-Factor Analyses for BP Cherry Point*

1. One of the deficiencies in BP Cherry Point's cost analyses is that it used a 5% interest rate in amortizing capital costs.[168] BP claimed that this interest rate was based on the past Federal Reserve Prime Rate, but the Federal Reserve Prime Rate has been at 3.25% since March 2020.[169] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[170] In a cost effectiveness analyses being done today, even a 5.0% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

2. For all of the units except the #5 boiler and the #3 reformer heater, BP used cost estimates that were previously done in 2010 and which reflected a 2007 dollar basis.[171] BP scaled those costs up from 2007 dollars to 2020 dollars using the Nelson Farrar Refinery Construction cost index, which increased capital costs by 41%.[172] EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis.[173] EPA states that "[e]scalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate."[174] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. Notably, for SCR, EPA's SCR cost effectiveness spreadsheet can be used to estimate costs of SCR, as was used by Ecology for the #1 reformer heaters, the crude heater, the reforming furnace #1 (N H2 Plant), and for the reforming furnace #2 (S H2 plant).[175]

3. BP Cherry Point stated that LNBs/ULNBs were not technically feasible on the crude charge heater, the naphtha HDS charge heater, the naphtha HDS stripper reboiler, and the

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[168] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-6.
[169] https://fred.stlouisfed.org/series/DPRIME.
[170] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[171] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses) at P-10 to P-13.
[172] *Id.* at P-13.
[173] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[174] *Id.*
[175] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189-191.

hydrocracker R-4 heater due to flame impingement and that they would need to rebuild the heater to accommodate the burner retrofit.[176] A review of the air operating permit for BP Cherry Point shows that most of these heaters and boilers were installed fifty years ago in 1970. Given the age of the heaters, it could be more economical to replace the heaters and boilers with new heaters equipped with state-of-the-art ultra-low NOx burners. The heaters could also be retrofitted with SCR, which Ecology found to be cost effective.[177]

4. BP Cherry Point Assumed that LNB and ULNB could only achieve NOx emission rates of 0.055 to 0.060 lb/MMBtu for forced and balanced draft heaters with air preheaters.[178] The company provided no citation or support for that statement. NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[179] Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[180]

5. BP applied retrofit factors to the costs of SCR which would increase the capital costs due to purported retrofit difficulty, but BP provided no justification for the use of retrofit factors. For the one unit for which BP utilized EPA's SCR cost spreadsheet, it must be noted that the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology must request justification and documentation for use of any SCR retrofit factors.

6. BP assumed a cost for ammonia reagent in the SCR systems of $0.33/lb, or $660/ton, which is unreasonably high.[181] No basis was cited for this cost. EPA's SCR Control Cost Manual chapter assumes a much lower cost for 29% aqueous ammonia of $0.293/gallon, based on the average cost for ammonia for 2016 from the U.S. Geological Survey's Minerals Commodities Summaries for which EPA provided a weblink.[182] The U.S. Geological Survey Minerals Commodities Report currently lists the 2020 average cost for ammonia at $220/ton.[183] Thus, BP's costs of ammonia reagent were greatly overstated. Use of anhydrous ammonia is the least expensive form of the reagent and is commonly

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[176] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses), at P16-P18.
[177] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189-191.
[178] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses), at P-8.
[179] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144, Attached as Ex. 10.
[180] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses), at P-20.
[181] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses) at Attachment B.
[182] See EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[183] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 116, available at https://www.usgs.gov/centers/nmic/mineral-commodity-summaries.

used at utility installations. The State must ensure that the most cost-effective approaches to controlling NOx emissions with SCR and also that wholly unjustified and unreasonably high costs for ammonia are not used. Notably, Ecology used EPA's default cost for 29% aqueous ammonia in its SCR cost calculations.[184]

7. BP assumed an SCR would operate 8,784 hours per year (i.e., the total number of hours in a leap year) in estimating the reagent costs for SCR at the South Vacuum Heater, which clearly is in error as that could only occur once every four years. BP also assumed 8,760 hours of operation for estimating reagent costs for SCR at the #1 Hydrogen Plant North and South Reforming Furnaces. Ecology must ensure that the assumed operating hours for estimating reagent costs are consistent with the baseline emissions and baseline capacity factor assumed in each SCR cost analysis.

8. With respect to non-air quality impacts of SCR controls, BP has indicated that spent catalyst will require off-site disposal or recycling.[185] However, EPA's Control Cost Manual states that use of rejuvenated and regenerated catalyst can both reduce catalyst replacement costs and eliminate catalyst disposal costs. Ecology must ensure that the SCR cost analyses assume the most cost-effective options for catalyst replacement.

9. BP assumed it would take 7 to 10 years to implement additional NOx control strategies.[186] The company states that it would need to follow the refinery maintenance turnaround (TAR) schedule, which is 5 to 6 years per unit, but it seems very unlikely that each unit is on the same maintenance schedule and instead the maintenance schedules are likely staggered.

In its public review draft regional haze plan, Ecology presented SCR cost effectiveness evaluations for the reformer heaters, the crude heater, and the hydrogen plant (North and South furnaces).[187] Ecology's cost effectiveness analyses were based on EPA's SCR cost spreadsheet, and it appears Ecology relied on the default cost assumptions of the EPA spreadsheet (such as the cost of ammonia and catalyst replacement cost).[188] Ecology assumed 90% NOx reduction with SCR, and Ecology assumed a 25 year life and a 3.25% interest rate in amortizing capital costs of control. The cost differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and BP's are very significant, as shown in the table below. This information is from Ecology's discussion in the narrative section of the draft regional haze SIP, and additional information on Ecology's costs are included in a spreadsheet printout in Appendix P of its draft plan.

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[184] WDOE, Public Review Draft, Regional Haze Plan for the Second Implementation Period, October 2021, Appendix P at P357.
[185] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses) at P-14.
[186] *Id.*
[187] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189.
[188] Based on a review of the tables with heading "EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020, Refineries Regional Haze Review – BP Cherry Point" in Appendix P of the WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at P-355 to P-361.

**Table 5. Summary from Draft Washington Regional Haze SIP: Comparison of BP's Cost Analysis to Ecology's Cost Analysis for SCR at Certain BP Cherry Point Emission Units[189]**

| BP's Capital Cost | BP's Annual Maintenance Cost | BP's Cost Effectiveness, $/ton | WDOE's Capital Cost | WDOE's Maintenance Cost | WDOE's Cost Effectiveness | NOx Reduced, tpy |
|---|---|---|---|---|---|---|
| **Reformer Heaters** | | | | | | |
| $94,809,582 | $420,048 | $24,378/ton | $9,929,730 | $49,649 | $3,101/ton | 304 tpy |
| **Crude Heater** | | | | | | |
| $94,809582 | $420,048 | $24,378/ton | $9,325,358 | $46,627 | $2,051/ton | 425 tpy |
| **Hydrogen Plant Reforming Furnaces** | | | | | | |
| $143,325,183 | $479,126 | $78,065/ton | $9,325,358 | $46,627 | $6,161/ton | 141 tpy |

BP's cost estimates are almost ten times as high as the SCR cost estimates for the same units calculated by Ecology with EPA's SCR cost spreadsheet. Ecology's analysis clearly shows that SCR at these BP Cherry Point units would be cost effective and would reduce NOx emissions by a total of 870 tons per year. Ecology states that BP did not provide the data it used to scale the cost data.[190] Thus, Ecology has found BP did not adequately support its SCR cost calculations.

Ecology did not find that the energy and non-air quality impacts of compliance with SCR should be an impediment to implementation of SCR, because the costs for the additional power needed to drive exhaust fans is included in the EPA Control Cost Manual SCR cost estimate.[191] Ecology also states that BP Cherry Point did not indicate that any equipment had a limited lifetime.[192] Ecology did state that the time necessary for compliance needed to accommodate installation during a planned shutdown to ensure reasonable costs, and Ecology states that installation of controls would likely occur in the next implementation period.[193] However, BP indicated in its four-factor submittal that currently scheduled cycle ending turnarounds for the emission units affected, which BP states vary from 2021 to 2026.[194] Thus, Ecology could ensure installation of SCR during the second implementation period and coordinate the installation with planned shutdowns at BP Cherry Point.

Ecology points out in its draft plan that the National Park Service has issued a finding to Ecology stating that emissions from BP Cherry Point "were adversely impacting air quality related values at North Cascades and Olympic National Parks."[195] Thus, Ecology should prioritize regional haze controls at the BP Cherry Point refinery to not only address regional haze but also to address visibility impairment at these parks which the National Park Service has reasonably attributed to the BP Cherry Point refinery. Ecology has found that SCR is cost effective for the

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189 Data from WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189-190 (Tables 7-8, 7-9, and 7-10).
190 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 191.
191 *Id.*
192 *Id.*
193 *Id.*
194 *Id.*, Appendix P at P-12 (BP Cherry Point Four-Factor Submittal).
195 *Id.* at 188.

reformer heaters, crude heater, and the hydrogen plant reforming furnaces to reduce NOx emissions by 90% from these emission units. Ecology should include these control requirements in its regional haze plan for the second implementation period.

### 3. Marathon Petroleum Company (MPC) Anacortes Refinery (Formerly Tesoro Refinery)

The Anacortes Refinery is currently owned by Marathon Petroleum Company (MPC) and was previously owned by Tesoro Refining & Marketing Company LLC (Tesoro, which Ecology also refers to as "Tesoro Northwest Company"[196]). Ecology calculated a Q/d value for the Tesoro Anacortes Refinery of 30.7, and it is ranked 6th highest Q/d on Ecology's list of sources it evaluated.[197] NPCA data shows that the facility likely impacts regional haze at 10 Class I areas.[198] Tesoro submitted a four-factor analysis of controls for the Anacortes facility on April 29, 2020.[199] In Ecology's review of NOx emission rates per 1,000 barrels per day (bpd) production rate at refineries nationwide, the Anacortes refinery formerly owned by Tesoro was at the highest emitter of NOx at 16.12 tons per year per 1,000 bpd production, which was two to five times as high as the NOx emissions per 1,000 bpd at all other refineries in the United States that Ecology reviewed.[200]

Tesoro submitted a four-factor analysis for FCCU and boilers and heaters greater than 40 MMBtu/hr. Specifically, Tesoro submitted a four-factor analysis for the following emission units at the refinery:

- Crude Heater 2
- Vacuum Flasher Heater
- CCU Feed Heater
- DHT Feed Heater
- Boiler 1
- Boiler 2
- Boiler 3
- NHT Feed Heater
- NHT Column C-6600 Reboiler
- CR Feed Heaters
- CO Boiler 2
- FCCU.

Tesoro only evaluated controls for NOx. The company stated that Ecology only requested evaluations of low NOx burners/ultra-low NOx burners and SCR. The following provides comments on Tesoro's cost effectiveness analyses in its Four-Factor submittal.

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[196] *Id.* at 185.
[197] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
[198] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[199] *Id.*, Appendix P at P-199 through P-291.
[200] *Id.* at 185-186 (Table 7-6).

*Issues with Four-Factor Analyses for Boilers and Heaters at Tesoro Refinery*

1. Tesoro did not conduct four-factor analyses for any heaters or boilers that had installed NOx controls since 2005.[201] However, none of Tesoro's heaters or boilers that it exempted from a four-factor analysis have installed controls to reduce NOx emissions. Those units that it exempted include Crude Heater 1 (Unit F-101), Crude Heater 3 (Unit F-103), CGS Column C C-113 Reboiler (Unit F-104), BenSat Column C – 6601 Reboiler (Unit F-6602), and Carbon Monoxide Boiler 2 (Unit F-302).[202] Given that SCR is such a highly effective NOx control, the state should require SCR installation for these units.

2. Tesoro used 2014 as the baseline year for cost effectiveness analysis for the various emission units, but it did not provide any analysis to show that 2014 emissions were reflective of emissions expected in 2028. EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions.[203] The use of emissions from over six years ago needs to be justified. For example, Tesoro assumed the CCU Feed Heater, Unit F-301, only operated 839 hours per year.[204] The Crude Heater 2 (Unit F-102) and the Vacuum Flash Heater (F-201) were evaluated at operational levels over 8,000 hours per year, whereas most other units were evaluated at lower operating hours in the range of 4,600-5,500 hours per year.[205] The annual hours of operation define how much pollution is emitted in a year and thus how much pollution can be decreased with a particular control being evaluated, which can greatly impact the cost effectiveness of a pollution control. Thus, the state should ensure that the assumptions are reasonable projections of emissions in 2028.

3. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Tesoro used an interest rate of 5.5%. In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

4. In the SCR cost analyses, a very high and unjustified cost of ammonia was assumed of \$900/ton.[206] No basis was cited for this cost. The company calculated a cost per gallon for 19.5% aqueous ammonia of \$3.513 per gallon.[207] Yet, EPA's SCR Control Cost Manual chapter assumes a much lower cost for 29% aqueous ammonia of \$0.293/gallon, based on the average cost for ammonia for 2016 from the U.S. Geological Survey's

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[201] *Id.*, Appendix P at P-207 (Tesoro Four-Factor Analysis).
[202] *Id.*
[203] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[204] Tesoro Four-Factor Analysis at pdf page 39 (Appendix A at F-301).
[205] WDOE, Public Review Draft, Second Regional Haze Plan, Appendix P, Tesoro Four-Factor Analysis at Appendix A in SCR cost spreadsheets for Units F-652, F-751, F-752, F-753, F-6600, F-6650/1/2/3, F-6601, and F-304.
[206] *Id.* at P-224 (Tesoro Four-Factor Analysis, Appendix A at F-102)
[207] *Id.*

Minerals Commodities Summaries for which EPA provided a weblink.[208] The U.S. Geological Survey Minerals Commodities Report currently lists the 2020 average cost for ammonia at $220/ton.[209] Thus, Tesoro's costs of ammonia reagent were greatly overstated. It is also not clear why only 19.5% aqueous ammonia was considered as a reagent. EPA's Control Cost Manual states that 29% aqueous ammonia is the more commonly used form of aqueous ammonia.[210] Use of anhydrous ammonia is the least expensive form of the reagent and is commonly used at utility installations.[211] The State must evaluate the most cost-effective approaches to controlling NOx emissions with SCR and must not use a wholly unjustified and very high cost for ammonia of $900/ton.

5. Tesoro's cost effectiveness evaluations of SCR used the EPA SCR cost spreadsheet that has been made available with its SCR Control Cost Manual chapter for all units except for the FCCU for which Tesoro used a cost estimate from a similar installation.[212] For the FCCU, only a one-page printout of an apparent spreadsheet was provided for review. The State should not accept cost effectiveness calculations without the underlying data and assumptions, so it can ensure that the cost analysis is consistent with the methodology of EPA's Control Cost Manual and that the assumptions for items such as reagent and catalyst costs are reasonable. In addition, EPA states "[i]f a cost quote or opinion prepared for one source is adopted or adapted to another source, EPA recommends the state explain in its SIP submittal how the source for which the original cost estimate was made is relevant to estimating the cost of compliance for the source in question."[213]

6. With respect to the use of EPA's cost spreadsheet for SCR, there is one entry made by Tesoro into the EPA cost spreadsheet that ultimately defines the size of the SCR reactor, and that is the "base case fuel gas volumetric flow rate factor" which is in units of $ft^3$/min-MMBtu/hr. These numbers seem very high in comparison to the values EPA uses for coal-fired boilers for which EPA defines as a constant for fuel type regardless of unit size or actual gas throughput.[214] Tesoro's fuel gas volumetric flow rate factors for each combustion turbine are roughly a factor of 100 higher than the fuel gas volumetric flow rate factors of 484-547 cubic $ft^3$/min-MMBtu/hour (depending on coal type) used by EPA in its SCR cost spreadsheet for coal-fired boilers.[215] If the state may rely on that information, Ecology must request documentation and justification for the base case fuel gas volumetric flow rate factors used by Tesoro.

7. Tesoro assumed NOx control efficiencies across the SCRs of 90%-96% for most boilers and heaters, with the exception of Boiler 3 (F-753) for which Tesoro only assumed a

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[208] See EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[209] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 116, available at https://www.usgs.gov/centers/nmic/mineral-commodity-summaries.
[210] EPA, Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 15.
[211] *Id.* at pdf page 5.
[212] Tesoro Four-Factor Analysis at Appendix A.
[213] U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 32.
[214] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 59, Table 2.6.
[215] Compare values used for flue gas volumetric flow rate factors in Draft Washington Regional Haze Plan, Appendix P, in Appendix A of Tesoro's Four-Factor Analyses to Table 2.6 of EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction.

control efficiency of 75%.[216] No justification was provided for assuming a much lower than typical NOx removal rate across the SCR.

8. With respect to the cost evaluations for ULNB for the heaters and boilers, Tesoro only assumed a 20-year life of controls in determining the amortizing the capital costs of control.[217] There was no basis provided for only assuming a 20-year life of ULNB.[218] If ULNB only have a life of 20-years, then the State should not exempt any boiler or heater from a four-factor analysis if it has installed controls by 2005 as claimed by Tesoro,[219] because the low NOx burners installed at Crude Heater 1 (F-101), Crude Heater 3 (F-103), CGS Column C-113 Reboiler (F-104), BenSat Column C-6601 Reboiler (F-6602), and Carbon Monoxide Boiler 1 (F-302)[220] will be at the end of their useful lives during the second planning period. Ultra-low NOx burners should have a useful life 25-30 years or more. In evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[221] In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR.[222] Thus, the State should not allow the use of a useful life of an ULNB any less than 25 years for the Tesoro units.

9. Tesoro did not provide justification for the NOx emission rate for the ULNBs. For most units, Tesoro assumed a 0.04 lb/MMBtu achievable NOx rate with ULNB.[223] Yet, the CGH Heater F-104, which has ULNBs,[224] is subject to a NOx limit of 0.035 lb/MMBtu.[225] The State should thus require an evaluation of ULNBs to meet a similar 0.035 lb/MMBtu NOx rate. For Units F-751 and F-752 which are boilers, a much higher NOx rate of 0.11 lb/MMBtu was assumed for ULNB.[226] Yet, Unit F-753 which is also a boiler of similar size to Units F-751 and F-752 but which has been retrofitted with low NOx burners and internal flue gas recirculation (IFGR),[227] Tesoro assumed a NOx rate of 0.04 lb/MMBtu in its evaluation of SCR cost effectiveness[228] which presumably reflects its current emission rate. Thus, Tesoro's evaluation of ULNBs for Units F-751 and F-752

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[216] WDOE, Public Review Draft, Second Regional Haze Plan, Appendix P, Tesoro Four Factor Analysis, Appendix A, SCR spreadsheet printouts.
[217] *Id.* at P-284 to P-291.
[218] *Id.* at P-219.
[219] *Id.* at P-207.
[220] *Id.*
[221] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).
[222] WDOE, Public Review Draft, Second Regional Haze Plan, Appendix P, at P-15 (BP Cherry Point Four-Factor Analysis).
[223] *Id.,* Appendix P at P-284 to P-291 (Tesoro Four-Factor Analyses).
[224] *Id.* at P-207 to P-208.
[225] January 26, 2010 Air Operating Permit #013R1 for Tesoro Refining and Marketing Company at 72 (Permit Term 5.2.13).
[226] WDOE, Public Review Draft, Second Regional Haze Plan, Appendix P at P-287 to P-288 (Tesoro Four-Factor Analyses).
[227] *Id.* at P-211.
[228] *Id.*at P-262.

should have evaluated cost effectiveness to meet a similar NOx rate as has been achieved at Unit F-753 with a similar control.

10. Tesoro did not evaluate the cost effectiveness of the most effective control – ULNB plus SCR.

In its public review draft regional haze plan, Ecology presented SCR cost effectiveness evaluations for seven emission units at the Anacortes refinery (FCCU, F102 Crude Heater, F201 Vacuum Flasher Heater, F6650 CAT Reformer Heater, F751 Main Boiler, and F752 Main Boiler).[229] Ecology's cost effectiveness analyses were based on EPA's SCR cost spreadsheet, and it appears Ecology relied on the default cost assumptions of the EPA spreadsheet (such as the cost of ammonia and catalyst replacement cost).[230] Ecology assumed 90% NOx reduction with SCR, and Ecology assumed a 25 year life and a 3.25% interest rate in amortizing capital costs of control. The cost differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and Tesoro's are very significant, as shown in the tables below. Note that Ecology refers to the cost estimates as "MPC" cost estimates, but the cost estimates are from Tesoro's April 20, 2020 Four-Factor Analysis of controls, which is in Appendix P of Ecology's draft regional haze plan.

Table 6 shows the differences in Tesoro's and Ecology's calculated capital costs and annual maintenance costs for SCRs at the FCCU and at the F102 Crude Heater, to show how significant the cost differences are between Tesoro and Ecology. This information was provided in and discussed in Ecology's draft regional haze plan.[231] Note that Ecology states that Tesoro's (MPC's) cost is based on SNCR controls at 60% NOx removal efficiency.[232] However, that appears to be in error. A review of Tesoro's four-factor analysis shows that the Tesoro cost numbers (labeled as MPC cost numbers in the draft plan) are reflective of SCR costs (not SNCR) to achieve 89.7% NOx control (not 60% control) and 833.10 tons per year of NOx reduction.[233]

Table 7 further below shows the difference in cost of SCR per ton of NOx removed between Tesoro and Ecology's cost analyses for all other units for which Ecology evaluated SCR costs. The differences in capital costs and maintenance costs of the units other than the FCCU and the F102 Crude Heater were not discussed in the narrative section of Ecology's draft plan but are provided in Appendix P of Ecology's draft second regional haze plan.[234] The differences in calculated SCR costs/ton of NOx removed make clear that Tesoro's costs are significantly higher than the costs calculated by Ecology using the EPA SCR cost spreadsheet provided with EPA's Control Cost Manual.

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[229] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 199.
[230] Based on a review of the tables with heading "EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020, Refineries Regional Haze Review – Tesoro" in Appendix P of the WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at P-347 to P-354.
[231] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021 at 199-200.
[232] *Id.* at 200.
[233] *Id.*, Appendix P at P-223.
[234] Ecology's specific cost data in Appendix P is difficult to ascertain from what appear to be printed tables from a spreadsheet that span several pages.

**Table 6. Summary from Draft Washington Regional Haze SIP, SCR Cost Analysis for the FCCU and the F102 Crude Heater at the Anacortes Refinery – Comparison of Tesoro's (MPC's) Cost Analysis to Ecology's Cost Analysis**[235]

| Tesoro's Capital Cost | Tesoro's Maintenance Costs ($/yr) | Tesoro's Cost Effectiveness, $/ton | WDOE's Capital Cost | WDOE's Maintenance Costs ($/yr) | WDOE's Cost Effectiveness | NOx Reduced, tpy |
|---|---|---|---|---|---|---|
| **FCCU** | | | | | | |
| $114,030,975 | $570,155 | $14,381/ton | $10,286,436 | $51,432 | $1,159/ton | 843.3 tpy |
| **F102 Crude Heater** | | | | | | |
| $20,876,000 | $104,380 | $16,086/ton | $5,084,927 | $25,425 | $2,962/ton | 147.6 tpy |

**Table 7. Comparison of SCR Cost Effectiveness as Calculated by Tesoro to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Anacortes Refinery**[236]

| Anacortes Refinery Emission Unit | Tesoro's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| FCCU | $14,381/ton | $1,159/ton | 843.3 tpy |
| F102 Crude Heater | $16,086/ton | $2,962/ton | 147.6 tpy |
| F201 Vacuum Heater | $35,276/ton | $7,589/ton | 57.6 tpy |
| F6650 CAT Reformer Heater | $21,196/ton | $3,736/ton | 117 tpy |
| F6651 CAT Reformer Heater | $21,196/ton | $3,520/ton | 124.2 tpy |
| F751 Main Boiler | $10,060/ton | $2,159/ton | 202.5 tpy |
| F752 Main Boiler | $10,513/ton | $2,570/ton | 170.1 tpy |

For SCR at the FCCU, Tesoro's cost estimates are roughly ten times as high as the SCR cost estimates for the same units calculated by Ecology with EPA's SCR cost spreadsheet. Ecology's analysis clearly shows that SCR at the FCCU would be cost effective at $1,159/ton and would reduce NOx emissions by 843 tons per year. For the F102 Crude heater, Ecology states that MPC (Tesoro) "incorrectly changed the default value for the $Ft^3$/min-MMBtu/hr input to the EPA Control Cost manual for all their determinations other than the FCCU."[237] That issue is discussed in Comment 6 above. Thus, Ecology has found Tesoro (MPC) did not adequately support its SCR cost calculations. Ecology's SCR cost estimates are much lower than Tesoro's (MPC's) for all of the emission units listed in Table 6 above. Assuming Ecology is using a $6,300/ton cost effectiveness threshold for refineries as it has proposed for the pulp and paper

[235] Data from WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189-190 (Tables 7-8, 7-9, and 7-10).
[236] *Id.* at 199.
[237] *Id.* at 200.

industry,[238] SCR must be considered a cost effective control for all units listed in Table 6 above except the F201 Vacuum Heater. Those cost effective SCR installations could collectively reduce NOx emissions from the Anacortes Refinery by 1,604.7 tons per year.

Ecology did not find that the energy and non-air quality impacts of compliance with SCR should be an impediment to implementation of SCR, because the costs for the additional power needed to drive exhaust fans is included in the EPA Control Cost Manual SCR cost estimate.[239] Ecology also states that MPC (Tesoro) did not indicate that any equipment had a limited lifetime.[240] Ecology did state that the time necessary for compliance needed to accommodate installation during a planned shutdown to ensure reasonable costs, and Ecology states that installation of controls would likely occur in the next implementation period.[241] However, if Ecology met the requirements of EPA's regional haze regulations and included final determinations to require SCR in this regional haze plan for the second implementation period, many of these SCR installations could occur during the second implementation period and be coordinated with maintenance outages at the Anacortes refinery.

Ecology points out in its draft plan that the Federal Land Managers have "made comments regarding the impacts to the Olympic [National Park] Class I area" in the context of commenting on a PSD permit for the Tesoro Anacortes Refinery.[242] Indeed, the National Park Service's 2017 comments stated that Tesoro Anacortes refinery contributed significantly to visibility impairment at North Cascades National Park and at Olympic National Park, and the Park Service noted that the refinery should be considered for controls in the next regional haze plan.[243] It is not clear whether these comments constituted a determination of reasonably attributable visibility impairment. Nonetheless, Ecology should prioritize regional haze controls at the MPC Anacortes refinery to not only address regional haze but also to address visibility impairment at Olympic National Park attributable to the refinery. Ecology has found that SCR is cost effective for the FCCU, CAT reformer heaters, main boilers, and the F102 crude heater. Ecology should include these control requirements in its regional haze plan for the second implementation period.

#### 4. Shell Puget Sound Refinery

The Shell Puget Sound Refinery is another refinery located near Anacortes, Washington. Ecology calculated a Q/d value for the BP Cherry Point facility of 24.5.[244] NPCA data shows that the facility can potentially impact regional haze at 8 Class I areas.[245] Shell submitted a four-factor analysis evaluating NOx controls for its FCCU and boilers and heaters greater than 40

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[238] *Id.* at 182.
[239] *Id.* at 201.
[240] *Id.*
[241] *Id.*
[242] *Id.* at 198.
[243] April 27, 2017 Letter from the National Park Service to the Washington Department of Ecology at 4, attached as Ex. 11.
[244] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
[245] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.

MMBtu/hr. The company stated that Ecology only requested evaluations of LNB/ULNB and SCR.[246] The units that Shell evaluated NOx controls for include the following:

- Vacuum Pipe Still (VPS) Charge Heater 1
- VPS Charge Heater 2
- Vacuum Tower Heater
- Delayed Coking Unit (DCU) Charge Heater
- Hydrotreater Unit 1 (HTU1) Charge Heater
- HTU1 Fractionator Reboiler
- HTU2 Stripper Reboiler
- Hydrotreater Unit 2 (HTU2) Fractionator Reboiler
- Catalytic Reforming Unit #2 (CRU2) Charge Heater
- CRU2 Interheater #1
- CRU2 Stabilizer Reboiler
- Erie City Boiler #1
- Cogen Gas Turbine Generator (GTG) Heat Recover Steam Generator (HRSG) with duct burners (GTG1, GTG2, and GTG3)

Shell states that Ecology narrowed the request to only LNB/ ULNB and SCR. Shell analyzed the cost effectiveness of LNB/ULNB and SCR for these units.

Shell concludes that SCR is not a cost-effective control for NOx emissions at the refinery.[247] Shell indicates that the cost-effectiveness of LNB is much lower than those of SCR. However, Shell argues that a more thorough, unit-specific evaluation by vendors will be required to determine if the installation of low-NOx is technically feasible and cost-effective.[248] It must be noted that several of the units listed above already have LNBs installed, as do some additional units at the Shell refinery which were not evaluated in the four-factor analysis. The following provides comments on Shell's cost effectiveness analyses in its Four-Factor submittals.

*Issues with Four-Factor Analyses for Shell Puget Sound Refinery*

1. Shell used 2019 emissions as baseline and stated that 2019 "is representative of the anticipated actual emissions in the near future."[249] Shell identifies the 2019 baseline emissions for NOx as 592.6 tons per year for "all applicable units."[250] It is not clear whether this includes all NOx emissions at the source, but emissions data provided in Ecology's draft second regional haze implementation plan for the years 2011 through 2018 show much higher NOx emissions, ranging from 1,054 tons per year to 1,409 tons per year.[251] EPA states that generally, baseline emissions for pollution control analyses should be based on a recent period of historical emissions. If a company is proposing that 2028 emissions will be significantly lower than past historical emissions, there must be a documented basis for that assumption such as enforceable requirements or a

[246] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-138 (Shell Puget Sound Refinery Four-Factor Analysis).
[247] *Id.* at P-148.
[248] *Id.*
[249] *Id.* at P-142.
[250] *Id.*
[251] *Id.* at 84 (Table 4-8).

documented commitment to participate in energy efficiency or renewable energy programs.[252] Ecology has indicated that 2014 emissions of 1,230 tons per year are the representative baseline NOx emissions and the expected 2028 emissions for the Shell refinery.[253] Given that Shell has not provided documentation to indicate that the much lower NOx baseline of 592.6 tons per year that it relied on as reflective of 2028 emissions is based on enforceable limits or other documented and verifiable commitments, the state is justified in assuming 2014 NOx emissions are reflective of 2028 emissions for the Shell Puget Sound Refinery.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Shell used an unreasonably high interest rate of 7%.[254] In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units except the Erie City Boiler, the Shell cost effectiveness analyses assumed a 20-year life of controls.[255] No justification has been included in Shell's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[256] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years.[257] In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR.[258] Thus, the State should not allow the use of a 20-year useful life of a LNB or an SCR to be assumed in the cost effectiveness analyses for any of the Shell units, with one possible exception being the Erie City Boiler 1 (ECB1).

4. With respect to the remaining useful life of the Erie City Boiler 1, Shell provided brief information for this boiler that "substantial upgrades will be required to replace the boiler's refractory and the boiler skin" and that "the remaining useful life of the unit is

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[252] *See* U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 29.

[253] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 84 (Table 4-8).

[254] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-146.

[255] *Id.* at P-196.

[256] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).

[257] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.

[257] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 80.

[258] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P4, P-15, and Attachment B of the BP Cherry Point Four-Factor Analysis.

expected to be less than 10 years."[259] The company assumed 8 years in its four-factor analysis for the Erie City Boiler.[260] Importantly, Shell did not indicate that it would be retiring Erie City Boiler 1. If Shell plans on these substantial upgrades to the boiler, then Ecology should not consider this boiler as having a shortened remaining useful life in the NOx control cost effectiveness analyses. If the company is planning to retire and replace the boiler within the next 8 years, then Ecology should impose an enforceable retirement date for the boiler.[261] Ecology should also require that any replacement boiler should, at the very least, be equipped with state-of-the-art NOx controls. The Erie City Boiler 1 currently has no controls and, at 182.4 tons per year, has the highest emissions of NOx of any of the units evaluated in Shell's four-factor analysis. Ecology should not allow this unit or its replacement to avoid controls because it is either going to be reconstructed or removed from service in the next 8-10 years.

5. In its four-factor analysis, Shell assumed that LNB would only achieve a NOx emission rate of 0.06 lb/MMBtu. Shell provided no justification for assuming such a high NOx emission rate with LNB. As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[262] In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control.[263] It is also worth noting that Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[264]

6. For SCR, Shell used the EPA SCR cost spreadsheet made available with EPA's recent update to its SCR chapter of the Control Cost Manual. However, Shell applied a very high retrofit factor of 1.5 to each SCR evaluation, without providing any justification for any retrofit factor much less a retrofit factor that increases SCR costs by 50%. The cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology must scrutinize the use of any retrofit factor. EPA's SCR cost spreadsheet already adds a retrofit factor of 20% compared to the cost of SCR installation at a new unit for SCR retrofits at existing units.[265] EPA's Control Cost Manual states that higher retrofit factors than 1 can be used "provided the reasons for using a higher retrofit factor are appropriate <u>and fully documented</u>."[266] No unit-specific documentation of the justification for higher SCR retrofit factors was included in Shell's four-factor submittal.

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[259] *Id.* at P-148 (Shell Four-Factor Analyses).
[260] *Id.*
[261] *See* EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 20, which states that a state "may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028."
[262] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144. (Ex. 10.)
[263] May 5, 2015 Air Operating Permit AOP 014R1M1 for Shell Puget Sound Refinery at 13 and 127.
[264] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-222 to P-291 (Appendix A of Tesoro Four-Factor Analysis).
[265] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 66.
[266] *Id.* (emphasis added)

7. Shell appears to have assumed that that the gas stream of each heater/boiler would need to be reheated to accommodate SCR.[267] However, Shell did not provide any data on each of the units for which these costs were included in the SCR cost effectiveness to indicate that reheating the gas stream to accommodate SCR operation is necessary. Ecology must request further information before it can justify the inclusion of these costs for reheating the gas stream for each of the emission units at the Shell refinery.

In its public review draft regional haze plan, Ecology presented SCR cost effectiveness evaluations for three emission units at Shell Puget Sound Refinery (Boiler #1 Erie City- 31G-F1, FCCU Regenerator Unit, and CRU2 Heater and Interheaters).[268] Ecology's cost effectiveness analyses were based on EPA's SCR cost spreadsheet, and it appears Ecology relied on the default cost assumptions of the EPA spreadsheet (such as the cost of ammonia and catalyst replacement cost).[269] Ecology assumed 90% NOx reduction with SCR, and Ecology assumed a 25 year life and a 3.25% interest rate in amortizing capital costs of control. The cost differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and Shell's are significant, as shown in the table below.

Table 8 shows the differences in Shell's and Ecology's calculated capital costs and annual maintenance costs for SCRs at the Boiler #1 Erie City, FCCU Regenerator Unit, and the CRU2 Heater, to show how significant the cost differences are between Shell and Ecology. This information was provided in and discussed in Ecology's draft regional haze plan.[270]

**Table 8. Comparison of SCR Cost Effectiveness as Calculated by Shell to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Shell Puget Sound Refinery[271]**

| Puget Sound Refinery Emission Unit | Shell's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| Erie City Boiler 1 | $12,511/ton | $2,441/ton | 179 tpy |
| FCCU Regenerator Unit | Not Evaluated | $1,948/ton | 521 tpy |
| CRU2 Charge Heater/Interheaters | $10,813/ton | $6,346/ton | 69 tpy |

For SCR at Erie City Boiler 1, Shell's cost estimates are more than five times as high as the SCR cost estimates for the same units calculated by Ecology with EPA's SCR cost spreadsheet.

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267 WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P Shell Four-Factor Analysis at Appendix B.
268 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 195.
269 Based on a review of the tables with heading "EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020, Refineries Regional Haze Review – Tesoro" in Appendix P of the WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at P-347 to P-354.
270 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021 at 195-196.
271 *Id.* at 195.

Ecology did not take into account a shortened remaining useful life of the boiler in its SCR cost effectiveness analysis, as Shell did. Ecology states "With an eight-year lifetime, a requirement for the boiler to be retired after this period would be justified and the boiler should be required to decommission. Any new boiler brought in to replace it would need to go through the permitting process as a new source."[272] Ecology stated in the draft regional haze plan that it will work with the Northwest Clean Air Agency "to have a regulatory order on the boiler to shut down by January of 2028."[273] It is not clear why such a regulatory order has not been established and included as part of this regional haze plan. Ecology should not allow the Erie City boiler to avoid regional haze controls without making the decommissioning and the requirement to obtain a permit for any replacement boiler as a new source (meaning not allowing a replacement boiler to "net out" of permitting review) enforceable requirements.

Shell did not evaluate controls for the FCCU regenerator unit, but Ecology did and found that SCR at that unit would be cost effective at $1,948/ton and would reduce NOx by 521 tpy. Ecology's analysis clearly shows that SCR at the FCCU would be cost effective. Ecology's analysis of SCR cost effectiveness at the CRU#2 heater and interheaters also shows that the cost effectiveness is reasonable.

Ecology did not find that the energy and non-air quality impacts of compliance with SCR should be an impediment to implementation of SCR, because the costs for the additional power needed to drive exhaust fans is included in the EPA Control Cost Manual SCR cost estimate.[274] Ecology did not indicate that Shell had stated that any equipment had a limited lifetime other than Erie City Boiler 1.[275] Ecology did state that the time necessary for compliance needed to accommodate installation during a planned shutdown to ensure reasonable costs, and Ecology states that installation of controls would likely occur in the next implementation period.[276] However, if Ecology met the requirements of EPA's regional haze regulations and included final determinations to require SCR in this regional haze plan for the second implementation period, these SCR installations could occur during the second implementation period and be coordinated with maintenance outages at the Shell Puget Sound refinery. Ecology found that the Shell Puget Sound Refinery had the second highest NOx emissions per 1,000 bpd production of all of the eighty-four refineries nationwide that it evaluated.[277] Ecology has found that SCR is cost effective for Erie City Boiler 1, the FCCU, regenerator unit, and the CRU #2 heater and interheaters. Ecology should include these control requirements (or, for Eric City Boiler 1, a requirement to be decommissioned by 2028) in its regional haze plan for the second implementation period.

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[272] *Id.* at 195-196.
[273] *Id.* at 197.
[274] *Id.* at 197.
[275] *Id.*
[276] *Id.*
[277] *Id.* at 185.

### 5. Phillips 66 Ferndale Refinery

Ecology calculated a Q/d value for the BP Cherry Point facility of 10.9.[278] NPCA data shows that the facility impacts regional haze at 5 Class I areas.[279] Phillips 66 provided four-factor analyses of NOx controls for the following emission units at its Ferndale Refinery:[280]

- Crude Heater
- Crude Heater
- Alky Heater
- Reformer - Pretreater heater
- Reformer heater
- Reformer heater
- Reformer heater
- Reformer heater
- #1 Boiler
- #2 Boiler
- #3 Boiler
- DHT Heater
- S-Zorb Heater.

Phillips 66 states that Ecology narrowed the request to only LNB/ ULNB and SCR.[281] Phillips 66 analyzed the cost effectiveness of LNB/ULNB and SCR for these units and concluded that neither SCR nor LNB are cost-effective control for NOx emissions reductions at the refinery.[282] The following provides comments on the four-factor analyses submitted by Phillips 66.

*Deficiencies and shortcomings in the Phillips 66 Analyses are as follows:*

1. Phillips 66 used a five-year average of annual emissions from 2014-2018 as baseline emissions.[283] EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions. Ecology has indicated that 2014 emissions of 723 tons per year are the representative baseline NOx emissions and the expected 2028 emissions for the Phillips 66 Ferndale

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[278] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
[279] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[280] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P37 to P-85 (Phillips 66 June 2020 Four-Factor Analysis). Note that Phillips 66 originally submitted its four-factor analysis in April of 2020 (also in Appendix P), but it revised the analysis in June 2020 because it claimed that "the burners currently in operation for the alkylation heater (17F-1) and the DHT heater (33F-1) are considered low-NOx burners," and thus Phillips 66 excluded LNBs as a control to be evaluated for these units. *See* June 29, 2020 cover letter to Phillips 66 June 2020 Four-Factor Analysis.
[281] *Id.* at P-43.
[282] *Id.*
[283] *Id.* at P-49.

refinery.[284] The state should ensure that the emission assumptions are reasonable projections of emissions in 2028.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Phillips 66 used an unreasonably high interest rate of 7%. In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units, the Phillips 66 cost effectiveness analyses assumed a 20-year life of controls.[285] No justification has been included in Phillip 66's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[286] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years. In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR. Thus, the State should not consider a useful life of a LNB or an SCR to be less than 25 years in the cost effectiveness analyses for any of the Phillips 66 units.

4. Phillips 66 assumed high NOx rates with LNB in the range of 0.09 to 0.23 lb/MMBtu.[287] As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[288] In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control.[289] It is also worth noting that Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[290] Moreover, the #1 boiler, the DHT Heater, and the S-Zorb heater at the Phillips 66 refinery, which all have LNB, have baseline NOx emission rates in the range of 0.031 to 0.042 lb/MMBtu, per Phillips 66 SCR cost effectiveness analysis.[291]

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[284] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 84 (Table 4-8).
[285] *Id.* at P-78 (Appendix B of Phillips 66 June 2020 Four-Factor Analysis).
[286] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natural gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944, 18953, 18960 (Apr. 8, 2015).
[287] *Id.*
[288] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144. (Ex. 10).
[289] May 5, 2015 Air Operating Permit AOP 014R1M1 for Shell Puget Sound Refinery at 13 and 127, available at https://nwcleanairwa.gov/?wpdmdl=6716.
[290] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-222 to P-291 (Appendix A of Tesoro Four-Factor Analysis).
[291] *Id.* at P-78 to P-84.

5. Phillips 66 assumed continual operation every hour of the year (i.e., 8,760 hours per year – 100% capacity factor) in assessing reagent and other operational expenses of SCR.[292] Unless the company demonstrates that its emitting units operated 8,760 hours per year during the baseline period, this assumption results in overstated operational costs.

6. Phillips 66 included the same dollar amount for construction and management costs, contingencies, and escalation for every SCR cost analysis. Specifically, the company included costs of $3,841,150 for construction and management, $1,323,000 for contingencies, and $168,300 for escalation for each SCR cost analysis.[293] These were all identified as "indirect capital costs."[294] Such costs are typically scaled to the size of the unit, but these costs clearly have not been scaled. For many units, these costs exceed the costs of the SCR and the direct installation costs. In addition, to the extent these costs include owner's costs, such as the costs for owner activities to oversee the project regarding engineering, management, and procurement, or to fund the project, such costs must be excluded from the cost effectiveness analysis. EPA does not allow owner's costs to be included in cost effectiveness analyses under the Control Cost Manual.[295]

In its public review draft regional haze plan, Ecology presented SCR cost effectiveness evaluations for two emission units at Phillips 66 Refinery (Crude Heater 1F-1 and the FCCU/CO Boiler).[296] Ecology's cost effectiveness analyses were based on EPA's SCR cost spreadsheet, and it appears Ecology relied on the default cost assumptions of the EPA spreadsheet (such as the cost of ammonia and catalyst replacement cost).[297] Ecology assumed 90% NOx reduction with SCR, and Ecology assumed a 25 year life and a 3.25% interest rate in amortizing capital costs of control. The cost differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and Phillips 66's cost estimates are significant, as shown in the table below.

Table 9 shows the differences in Phillip 66's and Ecology's calculated capital costs and annual maintenance costs for SCRs at the Crude Heater 1F-1, demonstrating how significant the cost differences are between Shell and Ecology. Table 9 also shows Ecology's cost effectiveness for SCR at the FCCU/CO Boiler. Phillips 66 did not evaluate any additional controls for the FCCU because in 2006, the company modified the unit to install enhanced selective noncatalytic reduction (ESNCR).[298] Ecology evaluated SCR for the FCCU because "FCC units are a large

[292] *Id.* at P-78 to P-84.
[293] *Id.* at P-81.
[294] *Id.*
[295] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 65.
[296] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 192-193.
[297] Based on a review of the tables with heading "EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020, Refineries Regional Haze Review – Phillips 66" in Appendix P of the WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at P-369 to P-375.
[298] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 193

source of NOx emissions at refineries that have them."[299] Further, the addition of a catalytic reactor would work in concert with the ammonia injection system of the existing SNCR, and thus SCR would not be incompatible with the existing ESNCR system.

**Table 9. Comparison of SCR Cost Effectiveness as Calculated by Phillips 66 to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Phillips 66 Refinery[300]**

| Phillips 66 Refinery Emission Unit | Phillips 66's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| Crude Heater 1F-1 | $12,225/ton | $2,640/ton | 166 tpy |
| FCCU/CO Boiler | Not Evaluated | $3,954/ton | 247 tpy |

For SCR at Crude Heater 1F-1, Phillips 66's cost estimates are more than five times as high as the SCR cost estimate for the same unit calculated by Ecology with EPA's SCR cost spreadsheet. Ecology commented that Phillips 66 did not supply the data they used to scale the SCR cost data.[301] Thus, Ecology has found BP did not adequately support its SCR cost calculations.

Phillips 66 did not evaluate controls for the FCCU/CO Boiler, but Ecology did and found that SCR at that unit would be cost effective at $3,954/ton and would reduce NOx by 247 tpy. Ecology's analysis of SCR cost effectiveness at the Crude Heater 1F-1 also shows that the control is cost effective.

Ecology did not find that the energy and non-air quality impacts of compliance with SCR should be an impediment to implementation of SCR, because the costs for the additional power needed to drive exhaust fans is included in the EPA Control Cost Manual SCR cost estimate.[302] Ecology did not indicate that Phillips 66 had stated that any equipment had a limited lifetime.[303] Ecology did state that the time necessary for compliance needed to accommodate installation during a planned shutdown to ensure reasonable costs, and Ecology states that installation of controls would likely occur in the next implementation period.[304] However, if Ecology met the requirements of EPA's regional haze regulations and included final determinations to require SCR in this regional haze plan for the second implementation period, these SCR installations could occur during the second implementation period and be coordinated with maintenance outages at the Phillips 66 refinery. Ecology found that the Phillips 66 Refinery had the fifth highest NOx emissions per 1,000 bpd production of all of the eighty-four refineries nationwide that it evaluated.[305] Ecology has found that SCR is cost effective for Crude Heater 1F1 and the

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[299] *Id.*
[300] *Id.* at 192-193.
[301] *Id.* at 193.
[302] *Id.* at 193.
[303] *Id.*
[304] *Id.*
[305] *Id.* at 185.

FCCU/CO boiler. Ecology should include these control requirements in its regional haze plan for the second implementation period.

### 6. U.S. Oil & Refining Company – Tacoma Refinery

U.S. Oil & Refining (U.S. Oil) owns a refinery in Tacoma. According to Ecology, the facility has a Q/d value of 3.2.[306] U.S. Oil submitted a four-factor analysis of NOx controls for the following emission units:[307]

- Package Steam Boiler B-4
- Package Steam Boiler B-5
- Process Heater H-11.

U.S. Oil states that Ecology narrowed the request to only LNB/ ULNB and SCR.[308] U.S. Oil analyzed the cost effectiveness of LNB/ULNB and SCR for these units and concluded that neither SCR nor LNB are cost-effective control for NOx emissions reductions at the refinery.[309]

*Deficiencies and shortcomings in the U.S. Oil Four-Factor Analyses are as follows:*

1. Rather than using a level of baseline emissions based on historical emissions at the emission units of the Tacoma refinery, U.S. Oil states that it is "implementing changes during the refinery's upcoming turnaround in early 2021 that will add significantly to heat recovery, thereby reducing the fired duties of these sources."[310] Specifically, the baseline NOx emissions assumed for the three emission units evaluated are as follows:

| | |
|---|---|
| Unit B-4 (Package Steam Boiler) | 24.96 tpy NOx |
| Unit B-5 (Package Steam Boiler) | 10.39 tpy NOx |
| Unit H-11 (Process Heater) | 31.56 tpy NOx[311] |

Ecology should request or make public how U.S. Oil's projection of future NOx emissions from these units compares to recent annual NOx emissions from these emission units.

EPA's regional haze guidance states with respect to the baseline control scenario for the control analysis that:

> Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one

[306] *Id.* at 162 (Table 7-1).
[307] *Id.*, Appendix P at P-292 to P-339 (U.S. Oil Four-Factor Analysis).
[308] *Id.* at P-297.
[309] *Id.* at P-297 to P-298.
[310] *Id.* at P-303.
[311] *Id.*

> reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another.[312]

Ecology should thus require that U.S. Oil identify the details of its changes, including providing verifiable information to quantify its projection of the future NOx emissions of these units. Further, Ecology must evaluate whether the changes at the refinery should be made into enforceable requirements, so as to ensure the refinery's continued operation at these emission rates throughout the second planning period and beyond.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. U.S. Oil used an unreasonably high interest rate of 7%.[313] In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units, the U.S. Oil cost effectiveness analyses assumed a 20-year life of controls.[314] No justification has been included in U.S. Oil's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[315] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years. In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR. Thus, the State should not allow the use of a useful life of a LNB or an SCR to be assumed in the cost effectiveness analyses for any of the U.S. Oil units.

4. U.S. Oil assumed NOx rates with LNB in the range of 0.060 to 0.072 lb/MMBtu. As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower. In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control. It is also worth noting that Tesoro evaluated

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[312] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[313] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P at P-337.
[314] *Id.* at P-308.
[315] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).

LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.

5. U.S. Oil applied a 1.5 retrofit factor to the costs for both ULNB and for SCR.[316] This is a very high retrofit factor which essentially increases the capital costs of controls by 50%. Yet, U.S. Oil did not provide unit-specific information to justify the 1.5 retrofit factor applied to each ULNB and each SCR evaluation. With respect to SCR, it must be noted that the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology must scrutinize the use of any retrofit factor in U.S. Oil's SCR cost estimates using EPA's SCR cost spreadsheet. EPA's SCR cost spreadsheet already adds a retrofit factor of 20% compared to the cost of SCR installation at a new unit for SCR retrofits at existing units. EPA's Control Cost Manual states that higher retrofit factors than 1 can be used "provided the reasons for using a higher retrofit factor are appropriate and fully documented." No unit-specific documentation of the justification for higher SCR retrofit factors was included in U.S. Oil's four-factor submittal. With respect to the 1.5 retrofit factor applied to the cost effectiveness evaluation of ULNBs, U.S. Oil states this factor was included "to account for the additional challenges of retrofitting a low-NOx burner in an existing heater."[317] This is not sufficient documentation to justify a retrofit factor, especially such a high retrofit factor.

6. U.S. Oil states that SCR will require flue gas reheating.[318] However, U.S. Oil did not provide any data on each of the units for which these costs were included in the SCR cost effectiveness to indicate that the current exhaust gas stream would necessitate reheating to accommodate effective SCR operation. Ecology must request further information to justify the inclusion of these costs for reheating the gas stream for each of the emission units at the Tacoma refinery before it takes such costs into consideration.

As it did with the other refineries, Ecology evaluated SCR cost effectiveness using EPA's SCR cost calculation spreadsheet made available with its Control Cost Manual for the Heater H-11. Ecology found that cost effectiveness of SCR would be $15,612/ton, which was lower than U.S Oil's calculated cost effectiveness of $18,649/ton, but Ecology still found that SCR was not cost effective for this heater.[319] However, as discussed in Comment 1 above, U.S. Oil assumed a lower baseline for its cost analysis because it is "implementing changes during the refinery's upcoming turnaround in early 2021 that will add significantly to heat recovery, thereby reducing the fired duties of these sources."[320] Ecology should require that U.S. Oil identify and verify the details of its changes, and Ecology should determine if it is necessary to make such changes in emissions into enforceable requirements.

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[316] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P at P-307 and at P-337 (Table B-2).
[317] *Id.* at P-337 (Table B-2).
[318] *Id.* at P-308.
[319] *Id.* at 202.
[320] *Id.* at P-303.

## B. Four-Factor Analyses for the Pulp and Paper Mills

Ecology requested four-factor controls analyses for seven pulp and paper mills. The Northwest Pulp & Paper Association (NWPPA) submitted four-factor analyses for several emission units associated the following six pulp and paper mills:

- Nippon Dynawave Packaging Company Longview
- Georgia-Pacific Consumer Operations, LLC (GP Camas)
- WestRock Longview, LLC
- WestRock PC, LLC Tacoma
- Port Townsend Paper Corporation
- Packaging Corporation of America (PCA) Wallula.[321]

Cosmo Specialty Fibers submitted a separate four-factor analysis of controls.[322]

It appears that Ecology did not request or conduct a four-factor analysis for the McKinley Paper Plant which is a pulp and paper plant and for which it identified a Q/d value of 83.1, which was the second highest Q/d value of all facilities evaluated by Ecology.[323] Ecology must conduct a four-factor analysis of controls for this facility, as it greatly exceeded Ecology's Q/d threshold of 10.

Ecology states in its draft regional haze plant that the pulp and paper mills are a lower priority than refineries because they "are not located as close to each other as the refineries so they do not have as great of a cumulative effect."[324] Ecology also states that the potential reduction in regional haze emissions from pulp and paper mills is "vastly less than the potential refinery emission reductions."[325] However, the McKinley Paper Company (for which Ecology inexplicably did not conduct a four-factor analysis of controls) has the second highest Q/d value (83.1) of any facility for which Ecology requested four-factor analyses.[326] Three other pulp and paper mills are in the top ten highest Q/d values as calculated by Ecology – the WestRock Tacoma facility, the Nippon Dynawave Packaging Company in Longview, and the Pt Townshend Paper Corporation.[327] While these facilities may not all be located nearby each other, these four facilities along with Cosmo Specialty Fibers, WestRock Longview, and Georgia Pacific Consumer Operations all have Q/d values that are greater than or equal to the Q/d

[321] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, Appendix O at O1 through O-190 (Reasonably Available Control Technology Analysis for Washington Pulp and Paper Mills, December 2019, Northwest Pulp & Paper Association).
[322] *Id.* At O-282 to O-311 (Cosmo Specialty Fibers Four-Factor Analysis, December 2019).
[323] *Id.* at 162.
[324] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 166.
[325] *Id.* at 167.
[326] *Id.* at 161.
[327] *Id.* at 160-161.

threshold of 10 that Ecology set for selecting sources for review. Thus, the decision to defer controls on any of these pulp and paper mills must be based on a four-factor analysis of controls, not a determination that the facilities might not have as great of a cumulative effect on regional haze as the refineries.

### 1. Comments on Ecology's Determination of Cost Effective Controls for the Pulp and Paper Mills

The pulp and paper mill four-factor analyses submitted by NWPPA and by Cosmo Specialty Fibers did not propose to find that any controls were cost effective. Ecology "evaluated and adjusted" these companies' cost information and provided a summary of its revised costs/ton in Appendix J of the draft regional haze SIP. Ecology's adjustments primarily included using a 3.25% interest rate for amortizing capital costs, adjusting the useful life of controls for some sources, and adjusting SNCR NOx control efficiency to 35% for some sources.[328] As will be discussed further below, further adjustments should have been made to the control cost assessments, but even with these changes, Ecology found the following controls would be cost effective based on Ecology's reasonableness cost thresholds. Ecology is assuming a NOx cost reasonableness threshold of $6,300/ton and a PM10 cost reasonableness threshold of $7,800/ton.[329] Ecology must provide justification for its cost reasonableness thresholds. Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton.[330] Colorado is also using a reasonableness cost threshold of $10,000/ton.[331] New Mexico is using a reasonableness cost effectiveness threshold of $7,000/ton.[332]

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[328] *Id.*, Appendix J at J-1 to J-3.
[329] *Id.* at 182-183.
[330] *See* Oregon Regional Haze State Implementation Plan for the Period 2018-2028, Aug. 27, 2021 Public Notice Draft, at 35, 45.
[331] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, available at https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v.
[332] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.

**Table 9. Ecology's Identification of Cost Effective Regional Haze Controls at Pulp and Paper Mills**[333]

| Plant | Emission Unit | Control | Cost Effectiveness, $/ton | RH Pollution Reduced, tons per year |
|---|---|---|---|---|
| Nippon Dynawave | Hog Fuel Boiler #11 | SCR | $5,466/ton | NOx -1,025 tpy |
| Nippon Dynawave | Hog Fuel Boiler #11 | SNCR | $5,413/ton | NOx - 500 tpy |
| Nippon Dynawave | Boiler #9 | SCR | $6,041/ton | NOx - 175 tpy |
| Nippon Dynawave | Boiler #9 | LNB | $2,754/ton | NOx - 97 tpy |
| Packaging Corp. of America (PCA) | Boiler #1 | LNB | $5,893/ton | NOx - 26 tpy |
| PCA | Boiler #2 | LNB | $4,834/ton | NOx - 30 tpy |
| West Rock Longview | Hog Fuel Boiler 20 | SNCR | $6,245/ton | NOx – 115 tpy |
| WestRock Tacoma | Lime Kiln #1 | Wet ESP | $6,964/ton | PM10 – 33 tpy |

All of the above-listed emission units and controls were identified as cost effective controls in Ecology's draft SIP narrative except SNCR at WestRock Longview's Hog Fuel Boiler 20 at a cost effectiveness of $6,245/ton based on a 20-year life (which was provided in the Appendix J "snapshot summary" of Ecology's revised cost calculations of the draft regional haze plan). However, based on Ecology's $6,300/ton NOx cost effectiveness reasonable threshold, SNCR at West Rock Longview's Hog Fuel Boiler 20 should also have been listed as a cost effective control. Assuming, as Ecology has, that SNCR would only reduce NOx emissions by 35%, SNCR at the West Rock Longview Hog Fuel Boiler 20 would reduce NOx by 115 tons per year.[334]

A longer life than the 20-year life Ecology assumed for LNBs, SNCR, and wet ESPs should have been used in its revised cost effectiveness analysis. For example, in its proposed regional haze review for SO2, NOx, and PM controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls (including LNB), SNCR, WESPs, and wet scrubbers in the cost effectiveness evaluation for these controls.[335]

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[333] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, at 183 and Appendix J at J-1.
[334] Based on a 35% NOx reduction from reported 2017 emissions of 328 tons per year, as identified in WDOE, Public Review Draft, Regional Haze Plan for the Second Implementation Period, Appendix O at O-190.
[335] 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).

With respect to SNCR, there is also ample support for assuming a useful life of 25-30 years. While EPA states in the SNCR Control Cost Manual chapter that it is assumed than an SNCR would have a life of 20 years, EPA also states that "[a]s mentioned earlier in this chapter, SNCR control systems began to be installed in Japan the late 1980's. Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993. In responses to another ICR, petroleum refiners estimated SNCR life at between 15 and 25 years."[336] Therefore, based on a 1993 SNCR installation date, these SCNR systems that EPA refers to are at least 28 years old which, all other considerations aside, strongly argues for a 30-year equipment life. Furthermore, an SNCR system is much less complicated than a SCR system, for which EPA clearly indicates the life should be 25 years for industrial units. In an SNCR system, the only parts exposed to the exhaust stream are lances with replaceable nozzles. The injection lances must be regularly checked and serviced, but this can be done relatively quickly, if necessary, is relatively inexpensive, and should be considered a maintenance item. In this regard, the lances are analogous to SCR catalyst, which is not considered when estimating equipment life. All other items, which comprise the vast majority of the SNCR system capital costs, are outside the exhaust stream and should be considered to last the life of the facility or longer. For all of these reasons, Ecology should not have assumed a life of SNCR of any shorter than 25 years, similar to what it assumed for SCR, and a similar lifetime of LNBs should also have been assumed.

In addition, Ecology states that it evaluated SNCR at a removal efficiency of 35% at the Cosmo hog fuel boiler to be consistent with what was assumed for SNCR at the other pulp and paper mills.[337] However, EPA's Control Cost Manual indicates NOx removal efficiencies for SNCR used at boilers in the pulp and paper industry can achieve a median NOx removal efficiency of 50% with urea used as the reagent with a range of 20-62%, and EPA states that the median NOx removal efficiencies with ammonia-based systems at such boilers range from 61-65%.[338] Ecology should not have assumed any lower NOx removal efficiency than 50% with SNCR, assuming use of urea as a reagent. Assuming only 35% NOx removal with SNCR understates the emission reductions achievable with SNCR at boilers used in the pulp and paper industry.

Had Ecology assumed a 25-year life for SNCR and a NOx removal efficiency 50%, it is very likely that SNCR would be cost effective at the West Rock Tacoma Boiler #6, West Rock Tacoma Hog Fuel Boiler 7, PCA's Hog Fuel Boiler, and at the Cosmo Hog Fuel Boiler, based on how close Ecology's SNCR cost effectiveness numbers for these units were to Ecology's $6,300/ton reasonableness threshold. Thus, Ecology should revise the SNCR cost effectiveness

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336 EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-54, available at https://www.epa.gov/sites/default/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf.
337 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, Appendix J at J-1.
338 EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-1 to 1-2, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

analyses for these units to take into account a higher NOx removal efficiency and a longer life of the controls.

With respect to the WestRock Tacoma Hog Fuel Boiler 7, Ecology calculated cost effectiveness of SCR for this boiler at $6,508/ton and SNCR at $6,634/ton which is very close to Ecology's $6,300/ton cost threshold.[339] Ecology stated in its Statement of Basis for the 2011 Air Operating Permit for the facility that the owner of the Tacoma plant requested an increase in the 0.20 lb/MMBtu NOx limit for the boiler and stated that "the 0.20 lb/MMBtu limit was established based on the usage of proper combustion control and previously approved overfire air improvement (OFA) to the power boiler, but the assumptions about the degree of NOx reduction from OFA were wrong."[340] The Statement of Basis further states that the boiler could not meet both the carbon monoxide limit and the NOx limit. The owner of the plant at that time apparently requested a higher NOx limit of 0.30 lb/MMBtu and a higher annual NOx limit of 782 tons per year, which would be a significant increase above the 0.20 lb/MMBtu and 522 ton per 12-month NOx limits that currently apply to the unit.[341] If NOx emissions are going to be allowed to be higher in a subsequent permit action, then both SCR and SNCR would readily be under Ecology's $6,300/ton NOx threshold using Ecology's assumed 20-year life. Further, just changing the SNCR equipment life to 25 years and the interest rate to 3.25% brings the cost effectiveness of SNCR at 35% control at Hog Fuel Boiler 7 to $6,269/ton, which is under Ecology's $6,300/ton cost threshold. For these reasons, Ecology should include the WestRock Tacoma Hog Fuel Boiler 7 in its list of emission units with cost effective NOx controls for at least SNCR. Also, Ecology should disclose the details of the Agreed Order 7688 that was apparently entered into for resolution of the NOx noncompliance issues.[342]

With respect to the Georgia Pacific (GP) Camas plant, Ecology states the plant is "no longer operating as a chemical pulp mill and the emissions will change."[343] According to NWPPA's four-factor report, the GP Camas facility still has some units that are operating , such as the No. 5 Power Boiler and the No. 11 Paper Machine, but it has shut down the Kraft mill, bleach plant, No. 4 Lime Kiln and the No. 4 Recovery Furnace.[344] To the extent that these changes impact Ecology's review of controls for the facility, Ecology must make these changes into enforceable requirements (which could be accomplished by no longer including the units in the facility's operating permit and making clear that any restart of these units would be permitted as new emission units).

Despite Ecology finding that NOx controls at five units and PM10 controls at one unit would be cost effective, Ecology has not proposed any controls for these facilities. Ecology states that "[a]fter we complete the reasonability analysis and determination for the refinery facilities, we

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339 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, Appendix J at J-1.
340 *See* WDOE, Statement of Basis, Air Operating Permit 000085-0, December 12, 2011, at 24, available at https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Industrial-facilities-permits/WestRock-Tacoma.
341 *Id.* at 7-8.
342 *Id.* at 24.
343 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, at 183.
344 *Id.*, Appendix O at page O-14.

plan to conduct a reasonability analysis at pulp and paper facilities. This will be included in a SIP revision or the next implementation period, depending on the timing."[345] Ecology states that it decided that pulp and paper mills are not their first priority for implementation because the pulp and paper mills do not have as much of a cumulative effect on Class I areas as the refineries, because the pulp and paper mills are not in close proximity.[346] Unless the close proximity of the refineries makes regional haze controls more cost effective (for example, if emission units might share pollution controls) or otherwise justifies controls under a four-factor analysis, Ecology's proposed approach is not consistent with the regional haze rules or guidance.

Ecology also lists two other reasons for prioritizing the oil refineries for controls over the pulp and paper mills for controls, including that the potential reduction in regional haze emissions from the pulp and paper mills is much lower than the potential reduction in refinery emissions from controls and that the PCA Wallula mill is generally downwind from the nearest Class I areas.[347] However, the four-factor analysis of the regional haze does not include visibility impacts of a source or source category. For the pulp and paper mills, Ecology is essentially using visibility impacts to reject otherwise cost effective emission controls, by claiming a lower cumulative impact from the pulp and paper industry and/or by claiming the emission reductions (and thus regional haze improvement) won't be as significant as it could be with controls at the refineries. Yet, Ecology decided to evaluate regional haze controls for all sources with a Q/d value greater than or equal to 10. All of the pulp and paper mills evaluated by Ecology have Q/d values that range between 15.6 (West Rock Longview) to 27.9 (WestRock Tacoma),[348] thus the facilities all have Q/d values well over Ecology's threshold level. Further, according to NPCA's analysis, the Nippon Dynawave facility likely affects regional haze in 21 Class I areas, the West Rock Tacoma and West Rock Longview facilities each potentially affect regional haze in 10 Class I areas, and the Port Townshend facility and Cosmo Specialty Fibers facility each likely affect regional haze in 5 Class I areas.[349] Thus, from a regional haze perspective, the decision to evaluate controls for these pulp and paper mills is justified and warranted.

Ecology did not evaluate the other three factors of the four-factor analysis for the sources and emission units for which it found cost effective controls, and thus that analysis is presented here. In terms of energy and non-air environmental impacts, the main issue raised by NWPPA is the cost of power to run the controls,[350] which is taken into account in the cost effectiveness analysis (including for SNCR and SCR) and thus has been addressed. NWPPA stated that all boilers and lime kilns have a remaining useful life of 20 years or more,[351] so the remaining life would not be reason to exclude controls from the regional haze plan. In terms of the time necessary for compliance, NWPPA states that it would take at least four years for compliance if additional

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345 *Id.* at 184.
346 *Id.*
347 *Id.*
348 *Id.* at 161.
349 NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
350 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, Appendix O-58 to O-62.
351 *Id.* at O-63.

controls were ultimately required.[352] NWPPA discusses the need to stagger installation of controls if multiple units at a facility required controls,[353] but that does not need to be considered an impediment to for implementing the controls that Ecology has found to be cost effective for the pulp and paper mills. Ecology has found that SCR is cost effective at Hog Fuel Boiler #11 and at Boiler #9 of the Nippon Dynawave facility,[354] LNB is cost effective at PCA Boilers #1 and #2, and that a wet ESP is cost effective at West Rock Tacoma Lime Kiln #1. In addition, Ecology also should have identified SNCR as cost effective WestRock Longview's Hog Fuel Boiler 20, for which it calculated revised cost effectiveness of $6,245/ton. At the minimum, Ecology should include these emission units control requirements in its regional haze plan for the second implementation period. Ecology should also re-evaluate costs of SNCR to take into account at least a 50% NOx removal efficiency and a 25-year life, which more realistically reflects the useful life of an SNCR system and which reflects the capabilities of an SNCR system at a pulp and paper mill unit. That analysis will likely result in SNCR being cost effective at additional emission units.

In the following sections, more specific comments on the four-factor analyses submitted for each pulp and paper mill are provided.

### 2. *Deficiencies that Appear in All of the NWPPA Pulp and Paper Mill Four-Factor Analyses*

The following provides general comments on the control evaluations and cost-effectiveness analyses that appear to apply to all of the NWPPA four-factor analyses.

NWPPA used an interest rate of 4.8% in amortizing capital costs of most of the controls evaluated.[355] For the evaluation of low NOx burners at the power boilers, NWPPA assumed a much higher interest rate of 7%.[356] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[357] The current bank prime rate is 3.25%.[358] In a cost effectiveness analyses being done today, interest rates in the range of 4.8% to 7% are unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

1. NWPPA assumed too short of a life of pollution controls in amortizing capital costs of controls. For example. NWPPA assumed 20 years for the life of particulate matter (PM) and NOx controls, such as a WESP, improvements to existing ESPSs, and combustion

[352] *Id.* at O262.
[353] *Id.* at O-62 to O-63.
[354] Ecology also found that SNCR is cost effective at these emission units, but SCR will result in much greater NOx reductions and has a similar cost effectiveness value as SNCR. See Table 9 above.
[355] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-86 to O-116 (Tables B-1 through Table B-31).
[356] *Id.*, Appendix O at O-159 to O-163 (Tables B-57 through Table B-61).
[357] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[358] https://fred.stlouisfed.org/series/DPRIME.

control upgrades. Further, NWPPA only assumed a 15-year life for the SO2 control of the addition of a caustic scrubber at lime kilns and for the addition of a wet scrubber to boilers. NWPPA only assumed a 10-year life for LNBs. ESPs, WESPs, scrubbers, LNBs and other combustion controls should all be considered to have a life of at least 25 years. For example, in its proposed regional haze review for SO2, NOx, and PM controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls, SNCR, WESPs, and wet scrubbers in the cost effectiveness evaluation for these controls.[359] One just needs to evaluate how long existing controls have been in place at some of the emission units at the pulp and paper mills to know that a 25-30 year life (or more) is a much more reasonable assumption than a 15-20 year life. For example, in the Statement of Basis for the WestRock Longview Tacoma Mill, Ecology states as a description of a 2007 permitting action for replacement of a wet scrubber that the "[e]xisting scrubber is 30 years old and nearing end of service life."[360] As another example, Recovery Furnace 22 at the WestRock Longview Tacoma Mill was constructed in approximately 1990 and equipped with an ESP, which was about 30 years ago.[361] In addition, the Georgia Pacific Camas Mill installed an ESP at Power Boiler #3 in 1992, approximately 29 years ago,[362] which is still in operation although NWPPA has indicated that the Camas Mill "does not plan to operate Boiler No. 3 going forward."[363] Thus, there are several examples of pollution controls having useful lives in the range of 25-30 years at pulp and paper mills. It is important for Ecology to require use of a realistic cost of pollution controls in amortizing capital costs of controls because the life of controls assumed has a significant impact on the annualized costs of controls, as does the interest rate.

2. NWPPA appears to use a $3,400/ton threshold to define whether pollution controls were cost-effective.[364] However, no justification has been provided for use of this cost threshold or any cost threshold for defining measures necessary to make reasonable progress, other than that NWPPA cites to the $3,400/ton cost threshold used in the Cross State Air Pollution Rule (CSAPR) for non-electrical generating units.[365] For any cost threshold selected by a state, EPA's regional haze guidance requires that the State Implementation Plan (SIP) "explain why the selected threshold is appropriate for that purpose and consistent with the requirements to make reasonable progress."[366] With respect to determining whether a pollution control is cost effective for a recovery furnace,

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359 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).
360 *See* Washington Department of Ecology, Statement of Basis, Air Operating Permit 0000078, WestRock Longview, LLN, December 15, 2020, at 12, available at https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Industrial-facilities-permits/WestRock-Longview.
361 *Id.* at 10.
362 *See* Southwest Clean Air Agency, Title V Basis Statement, SW20-24-R0-A, Georgia-Pacific Consumer Operations LLC, December 17, 2020, at 7, available at https://www.swcleanair.gov/docs/permits/TitleV/SW20-24-R0-ABAS.PDF.
363 *See* December 2019 NWPPA Report at 1-5.
364 *Id.* at 2-12 and at 3-16.
365 *Id.*
366 EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 39.

lime kiln, or power boiler, it is important to consider the costs that similar sources have had to bear to meet Clean Air Act requirements.

The NWPPA Four-Factor Report identifies several examples of pollution controls being installed at the pulp and paper mills evaluated in its report. For example, the burner at the lime kiln at Nippon Dynawave Packaging Company was replaced with a staged combustion natural gas burner in 2017 and the kiln no long fires fuel oil.[367] As another example, an SNCR system was installed at Power Boiler No. 20 of the WestRock Longview Mill in 2012.[368] At the WestRock Tacoma Mill, Power Boiler No. 7 has a spray tower wet scrubber installed on Power Boiler No. 7 in 2017 and low-NOx burners were installed on Power Boiler No. 6 in 2018.[369] The package boiler at Pt Townshend Paper was converted to fire only natural gas using a low-NOx burner in 2016.[370] The hogged fuel boiler at the PCA Wallula Mill had an overfire air system and a WESP installed in 2016.[371] Regardless of the reasons that these controls were installed, the fact that the controls were installed by the companies is indicative of the cost-effectiveness of the controls.

3. NWPPA estimated costs for certain controls based on a report from 2003. Specifically, NWPPA used cost information from the May 1, 2003 report from the National Economic Research Associates (NERA) entitled "Evaluation of Air Pollution Control Costs for the Pulp and Paper Industry."[372] NWPPA used the cost estimates from this report to develop scaled capital cost estimates for WESPs, upgrades to ESPs, and for wet scrubbers.[373] NWPPA escalated costs from the 2003 cost basis of the NERA report to 2018 dollars using the Chemical Engineering Plant Index (CEPCI).[374] However, EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis.[375] EPA states that "[e]scalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate."[376] Further, the cost of an air pollution control does not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

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367 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-12 to O-13.
368 *Id.* at O-13.
369 *Id.*
370 *Id.*
371 *Id.* at O-14.
372 *Id.* at O-164 through O-189.
373 *Id.*
374 *Id.*, at O-86 through O-90, O-110 through O-113, O-116 (Appendix B at Tables B-1 through B-5, B-8, B-25 through B-28, and B-31).
375 EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
376 *Id.*

4. NWPPA included costs for sales taxes, property taxes and insurance in its capital costs of controls for several controls evaluated.[377] Yet, in many cases, property taxes do not apply to capital improvements made such as air pollutant controls, and pollution controls are not necessarily considered as increasing risks to necessitate higher insurance costs.[378] In addition, it appears that air pollution controls would be exempt from Washington sales taxes.[379] Ecology must not allow NWPPA to artificially inflate costs by items that likely would not apply to pollution control installations and upgrades.

5. NWPPA somewhat readily dismissed switching/converting to less polluting fuels, stating such fuel switches were too costly without providing sufficient detail for the assumptions of its cost analyses. Specifically, for SO2 control at recovery furnaces, NWPPA stated that the cost of switching to low sulfur No. 2 fuel oil was $12,000/ton based on a 10% capacity factor.[380] It is not clear why the assumption of only a 10% capacity factor is justified for all recovery furnaces that could switch to lower polluting fuels. NWPPA did state that "some recovery furnaces are limited by their air permit to an annual heat input of less than 10% fossil fuel…for avoidance of additional NSPS requirements."[381] However, NWPPA did not identify which of those recovery furnaces had capacity factor limitations, nor did NWPPA explain how those NSPS requirements that the facilities were avoiding with capacity factor limitations might differ if the units utilized a less polluting fuel. Yet, several units have switched from No. 6 fuel oil to No. 2 fuel or from fuel oil to natural gas, as discussed in the NWPPA report in Section 1.2.1 "Summary of Recent Emissions Reductions." Switching to lower sulfur fuel provides the least capital-intensive approach to significantly lowering SO2 emissions, and thus Ecology should not allow such fuel switches to be so readily dismissed as not cost effective without adequate documentation and justification. Indeed, other benefits of switching to less polluting fuels should also be considered in the four-factor analysis. For example, burning of natural gas requires less maintenance than the burning of fuel oil. Thus, Ecology must require that switching to less polluting fuels be more thoroughly evaluated and that any cost effectiveness evaluations be documented with data specific to each furnace or boiler for which this control is evaluated.

In addition to these general concerns that apply to NWPPA's cost effectiveness analyses, the following provides more specific comments to the cost effectiveness evaluations for lime kilns and for power boilers.

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377 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-86 to O-116 (Appendix B at Table B-1 through B-31).
378 *See*, e.g., EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80 (Equation 2.69). See also EPA Control Cost Manual, Section 4, Chapter 1 (SNCR), at 1-54.
379 WAC 458-20-242A.
380 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-23.
381 *Id.*

### 3. Comments on SO2 Controls for Lime Kilns

NWPPA states that all lime kiln SO2 emissions are low, "meaning that installing additional SO2 controls would not be cost effective."[382] The emissions presented to make this argument for each facility's lime kilns are from 2017, but NWPPA has not provided any analysis to indicate that operations and SO2 emissions from the lime kilns in 2017 are indicative of typical operating emissions. EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions.[383] Ecology should obtain more information to ensure that these emissions are reflective of typical operations.

EPA stated in a 2014 document that nearly 70% of lime kilns in the pulp and paper industry are equipped with wet scrubbers.[384] Of the lime kilns that NWPPA evaluated, the WestRock Longview Mill Lime Kiln 5 had the highest SO2 emissions in 2017 and is not equipped with a wet scrubber, according to NWPPA's Four-Factor Report. Ecology should evaluate whether this lime kiln's emissions are properly characterized by 2017 data and consider evaluating the addition of a wet scrubber for SO2 control and also PM control.

### 4. Comments on of NOx Controls Evaluations for Power Boilers

NWPPA evaluated NOx controls for several power boilers at the six pulp and paper mills. The controls to be evaluated differed based on the fuel utilized and presumably the boiler type and existing controls. Generally, SNCR and SCR were evaluated for all boilers, and LNB were evaluated for several boilers. The following provides comments on deficiencies noted in NWPPA's NOx cost effectiveness analyses.

1. For SNCR cost evaluations, NWPPA assumed 35% control of NOx, regardless of the NOx inlet rate to the SNCR system.[385] NWPPPA did not provide any justification for that assumption. EPA's Control Cost Manual indicates NOx removal efficiencies for SNCR used at boilers in the pulp and paper industry as achieving a median NOx removal efficiency of 50% with urea used as the reagent with a range of 20-62%.[386] EPA also stated that median NOx reductions with ammonia-based SNCR systems are 61-65% and that most boilers with ammonia-based SNCR systems that are solid fuel-fired are fired

[382] *Id.* at O-24.
[383] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[384] U.S. EPA, Universal Industrial Sectors Integrated Solutions Model for Pulp and Paper Manufacturing Industry – Universal ISIS-PNP, November 2014, at 2-40, available at https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=311359.
[385] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-43 and O-45.
[386] EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-2, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

with wood or municipal solid waste.[387] Thus, NWPPA has greatly underestimated the NOx reduction capabilities and cost effectiveness of SNCR by only assuming 35% NOx control. Ecology should consider SNCR to achieve at least 50% NOx control at power boilers used in the pulp and paper industry if urea is the reagent.

2. NWPPA used EPA's SNCR cost calculation spreadsheet made available with its Control Cost Manual.[388] For the SNCR control evaluations, NWPPA assumed a 1.5 retrofit factor, which essentially increases capital costs by a factor of 1.5. NWPPA states that "the costs algorithms [of EPA's cost spreadsheet] were developed based on project costs for large coal-fired utility boilers" and assumed, without providing any further justification that EPA's cost algorithms "likely underestimate costs for smaller industrial boilers." Thus, NWPPA applied a retrofit factor of 1.5 "to account for the need to add multiple levels of injectors and perform additional tuning of the system across loads."[389] This was not a justified cost increase. EPA's Control Cost Manual chapter on SNCR costs states there is very little difference in the costs to retrofit SNCR to existing boilers compared to new boilers.[390] EPA's SCNR cost spreadsheet states that it can be used for industrial boilers with maximum heat input capacities of 250 MMBtu/hour or greater and, while EPA has acknowledged that capital costs increase for smaller boilers, the costs do not increase by 50% except for very small boilers.[391] Thus, Ecology should not allow use of any retrofit factor for SNCR costs at any of the power boilers without sufficient documentation from NWPPA or the facility owners to justify the use of a retrofit factor.

3. NWPPA used EPA's SCR cost calculation spreadsheet made available with its Control Cost Manual.[392] EPA's SCR cost spreadsheet already provides a 20% retrofit factor for SCR retrofits as compared to SCR installation costs on a new facility.[393] In addition, the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs, especially due to the large sizes of the SCR reactors and the need for specialized cranes to maneuver large SCR reactors into tight or elevated spaces. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. NWPPA did not provide adequate justification for its application of a 1.5 retrofit factor to SCR cost analyses for power boilers. NWPPA simply said "[a] retrofit factor of 1.5 was applied to all industrial boilers since the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, and the likelihood of needing a

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387 *Id.* at 1-1.
388 Available at [https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution](https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution).
389 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-55.
390 EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-6.
391 *Id.* at 1-7 (Figure 1.2).
392 Available at [https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution](https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution).
393 This is evident by the fact that if one enters in the Data Inputs tab that the SCR is for a new boiler, the retrofit factor drops from 1 to 0.8.

new ID fan to account for increased pressure drop."[394] Ecology must not allow use of retrofit factors in the SCR cost analyses unless justified based on the specific situation for a particular power boiler.

4. NWPPA did not provide data on the assumptions that went into the cost effectiveness of SCR or SNCR for the power boilers. For example, NWPPA's four-factor submittal does not identify the baseline NOx emissions and emission rates of each boiler in tons per year and lb/MMBtu. It also did not identify the operating hours and/or operating capacity factor of each power boiler used in estimating the operational expenses of these controls. In addition, NWPPA did not identify specific costs assumed for the SNCR and SCR reagent (including what type of reagent was assumed) or the electricity costs. It also is not clear what unit characteristics and fuel characteristics were assumed in the cost spreadsheets for each boiler. Had NWPPA provided a printout of all pages of EPA's SNCR and SCR spreadsheets in its four-factor report, this information could be evaluated. Ecology must ask NWPPA to make all of the pages of the SNCR and SCR spreadsheets available for review for the power boilers.

   It must be noted that the calculated NOx emission reductions for SNCR and SCR seem inconsistent with the baseline emissions assumed for the boilers evaluated for LNB control. Specifically, one can back-calculate the assumed uncontrolled emissions for a boiler by dividing the NOx reductions presented in the spreadsheet printouts for SNCR and SCR by the assumed 35% (for SNCR) and 90% (for SCR) NOx removal efficiency. When we back-calculated those uncontrolled NOx emission rates for the five power boilers that were evaluated for LNB controls (i.e., Nippon Dynawave Boilers 6, 7, and 9 and PCA Wallula Boilers 1 and 2), we found the resulting "uncontrolled NOx emissions" assumed in the SNCR and SCR analyses for these boilers were about 55% higher than the uncontrolled NOx emissions assumed for these units in the LNB cost analyses.[395] Ecology should further evaluate these emission calculations to ensure consistency across all analyses, and to ensure that the baseline NOx emissions truly reflect actual baseline emissions for the power boilers. Having NWPPA submit the entire spreadsheets for these cost calculations would greatly help in ensuring consistency and accuracy of the cost effectiveness calculations.

5. For the analysis of LNBs, NWPPA used a John Zink cost analysis from 2016 for a 99 MMBtu/hr gas-fired boiler.[396] For this analysis, NWPPA inexplicably assumed a 7% interest rate rather than the 4.7% interest rate it assumed for its other cost analyses.[397] As discussed above, there is no justification for such a high interest rate, and Ecology should make sure the current prime rate be used in cost analyses, to be consistent with EPA's

[394] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-57.
[395] *Id.*, Appendix O at O-159 to O-163 (Tables B-57 through Table B-61). The LNB cost analyses for these power boilers identify baseline NOx emissions.
[396] *Id.* at O-57.
[397] *Id.* At O-159 to O-163 (Tables B-57 through Table B-61).

Control Cost Manual. In addition, NWPPA's cost effectiveness analyses of LNB for power boilers assumed LNBs would only have a life of 10 years.[398] Low NOx burners should have a useful life of 25-30 years or more. In evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[399] Thus, NWPPA was not justified in assuming such a short lifetime of LNB and such a high interest rate, and these invalid assumptions improperly made LNB appear to be less cost effective.

It is also questionable whether NWPPA's assumption of only 50% NOx reductions with LNB is a reasonable estimate of achievable emission reductions with LNB. EPA states that NOx emission reductions of 40 to 85% are achievable with low NOx burners.[400] In addition, NWPPA did not evaluate flue gas recirculation (FGR) in combination with LNB. EPA states that these controls are normally used together to reduce NOx, and emission reductions of 60 to 90% are achievable.[401] Indeed, the No. 5 Power Boiler at the Georgia Pacific Camas Mill is equipped with these controls.[402] Ecology must ensure that NWPPA evaluates the most effective combustion controls for the power boilers.

It is important to note that just revising the annualized capital costs of LNBs using NWPPA's cost numbers but using a capital recovery factor reflective of a 3.25% interest rate and a 25-year life makes a significant difference in the cost effectiveness of LNBs at the power boilers, as the table below demonstrates.

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398 *Id.*

399 *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).

400 EPA, AP-42 Emission Factor Documentations, Section 1.4 Natural Gas Combustion, at Section 1.4.4, available at https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.

401 *Id.*

402 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-48.

**Table 10. Revisions to NWPAA's Cost Effectiveness of LNBs at Power Boilers to Use a Lower Interest Rate and a More Realistic Life of LNB Controls (3.25% Interest Rate, 25-Year Life of LNB)**

| Plant-Unit | Total Annualized Costs (at 3.25% Interest and 25 Year Life) | NOx reductions (per NWPPA), tpy | Revised Cost Effectiveness (at 3.25% Interest Rate and 25-Year Life) | NWPPA's Cost Effectiveness (at 7% Interest Rate and 10-Year Life) |
|---|---|---|---|---|
| Nippon Dynawave Boiler 6 | $141,708 | 18.55 | $7,639 | $12,093 |
| Nippon Dynawave Boiler 7 | $168,795 | 28 | $6,028 | $9,543 |
| Nippon Dynawave Boiler 9 | $250,813 | 97.3 | $2,578 | $4,081 |
| PCA Wallula Boiler 1 | $142,579 | 25.85 | $5,516 | $8,732 |
| PCA Wallula Boiler 2 | $136,856 | 30.3 | $4,517 | $7,162 |

As the Table 10 demonstrates, the use of an unreasonably high interest rate and an unreasonably low useful life of controls can greatly distort the cost effectiveness of controls. Not only do revisions to the cost effectiveness analyses to reflect appropriate interest rates and life of controls improve the cost effectiveness of LNB, but such revisions would also improve the cost effectiveness of SNCR and SCR for the power boilers. Moreover, if more realistic levels of NOx reduction were assumed with LNB and also with SNCR, those controls would likely be more cost effective. Further, as previously stated, no retrofit factor was justified to the SNCR costs or the SCR costs and revising the costs to eliminate the retrofit factor applied would also make those controls more cost effective. Indeed, with these revisions made, it is likely that LNB and/or SNCR would be considered very cost effective for several of the power boilers at the pulp and paper mills. Further, a review of the cost inputs used in the SCR cost analyses is imperative to ensure that costs for items such as reagent, electricity, or catalysts were not overstated in those analyses.

### 5. Comments on Four-Factor Analyses for the Cosmo Specialty Fibers Mill

Cosmo Specialty Fibers (Cosmo) operates a sulfite pulp mill located in Cosmopolis, Washington. A four-factor analysis was submitted for controls at one emissions unit at the plant: the hog fuel boiler at the facility.[403] Cosmo did not provide four-factor analyses for the recovery boilers at the facility (Recovery Boiler 1, 2, and 3), nor did Cosmo provide four-factor analyses for the hogged fuel dryer at the facility.

Cosmo relied on Ecology's 2016 analysis entitled "Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills" dated November 2016 to justify no additional regional haze controls for its recovery boilers.[404] However, the November 2016 Ecology RACT analyses was focused on whether the visibility benefits of pollution controls evaluated justified the costs of the pollution controls. As previously discussed, the visibility benefits of controls are not part of the Clean Air Act's four-factor analysis; thus, Ecology's determination should not add an additional factor to the four statutory factors. It must also be pointed out that Ecology's 2016 RACT analysis was based on emission inventories between 2003 to 2011 and, as noted in the 2016 RACT analysis, Cosmo did not operate from 2007-2010.[405] In fact, a support document for a Title V permit for the Cosmo facility states that when the Cosmo mill restarted in 2011, it had eliminated two processes (cellophane and paper grade production) and only produced dissolving pulp.[406] That basis statement also stated that "[p]roduction varies upon market demand."[407] Thus, Ecology's 2016 report did not have much emissions data reflective of the new operations at the Cosmo facility to base a cost effectiveness analysis of pollution controls on, and a revised analysis of pollution controls must be done for these emission units reflective of current emissions that reflect expected operations in 2028. For these reasons, Ecology's 2016 RACT analysis must not exempt a facility from evaluating pollution controls for any part of its facility.

Cosmo evaluated SCR and SNCR for NOx controls at the hog fuel boiler and evaluated use of an ESP to reduce PM emissions from the hog fuel boiler. Cosmo determined that no additional controls are required at the hog fuel boiler to address regional haze requirements.[408]

*Deficiencies in Cosmo's cost effectiveness analyses*

1. Cosmo assumed a 4.75% interest rate in amortizing capital costs of the controls evaluated.[409] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[410] The current bank prime

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[403] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-278 to O-312 (December 2019 Four-Factor Analysis for Cosmo Specialty Fibers).
[404] *Id.* At O-288.
[405] Washington Department of Ecology, Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills, November 2016, at 34.
[406] Support Document for the Air Operating Permit issued to Cosmo Specialty Fibers, [undated], at 4, available at https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Industrial-facilities-permits/Cosmo-Specialty-Fibers.
[407] *Id.*
[408] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-285.
[409] *Id.* at O-306 to O-308 (Appendix B, Tables 1b, 2b, and 3b).
[410] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

rate is 3.25%.[411] I n a cost effectiveness analyses being done today, an interest rate of 4.75% is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

2. Cosmo assumed too short of a life of pollution controls in amortizing capital costs of controls. Cosmo only assumed a 20-year life in its cost effectiveness evaluations for SCR, SNCR, and ESP.[412] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years.[413] As stated above in the comments on the NWPPA facilities, a simple review of pollution controls at existing boilers and furnaces in the pulp and paper industry shows that pollution controls like ESPs are in place for 25 to 30 years or more. For example, Recovery Furnace 22 at the WestRock Longview Tacoma Mill was constructed in approximately 1990 and equipped with an ESP, which was about 30 years ago.[414] Further, the Georgia Pacific Camas Mill installed an ESP at Power Boiler #3 in 1992, approximately 29 years ago.[415] Thus, a 25-30 year life is likely a more appropriate life of controls to use in amortizing capital costs of a pollution control for the hog fuel boiler. In its proposed regional haze review for SO2, NOx, and PM controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls, SNCR, WESPs and wet scrubbers.[416] It is important for Ecology to use of a realistic life of pollution controls in amortizing capital costs of controls, because the life of controls assumed has a significant impact on the annualized costs of controls, as does the interest rate.

3. In the evaluation of SNCR for NOx control, Cosmo only assumed 25% NOx control would be achieved.[417] Cosmo stated this lower NOx control efficiency was applied due to the "load-swing nature of the Hog Fuel Boiler as well as low NOx concentration…."[418] Ecology should request more information from Cosmo on the load-swing nature of the boiler and how that could impact NOx removal efficiency with SNCR. The hog fuel boiler does appear to run throughout the year, as Cosmo stated the typical operating level of the unit was 357 days per year at 24 hours per day.[419]

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[411] https://fred.stlouisfed.org/series/DPRIME.
[412] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-306 to O-308 (Appendix B, Tables 1b, 2b, and 3b).
[413] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[413] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 80.
[414] *Id.* at 10.
[415] *See* Southwest Clean Air Agency, Title V Basis Statement, SW20-24-R0-A, Georgia-Pacific Consumer Operations LLC, December 17, 2020, at 7, available at https://www.swcleanair.gov/docs/permits/TitleV/SW20-24-R0-ABAS.PDF.
[416] 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).
[417] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-295.
[418] *Id.*
[419] *Id.* at O-295 (Table 4-2).

4. In the evaluation of SCR for the hog fuel boiler, Cosmo assumed that the flue gas would need to be reheated and Cosmo took into account estimated costs to reheat the flue gas in the SCR cost effectiveness analysis.[420] The cost for reheating the flue gas reflects 85 to 88% of Cosmo's total annual costs of SCR.[421] Cosmo did not provide the detailed calculations to verify the costs for reheating the flue gas stream, and Ecology must request that data.

5. Cosmo did not evaluate the cost effectiveness of a high dust SCR system which would eliminate any need for flue gas reheating, thus reducing Cosmo's annual cost estimates of SCR significantly. Cosmo's justification for not evaluating a high dust SCR was concerns about particulate emissions poisoning the SCR catalyst.[422] However, there are options to reduce or slow down catalyst deactivation that should have been considered. One study on this issue states that SCR catalyst deactivation in biomass fired plants is mostly due to high potassium content in biomass and that one method to deal with that is potassium removal by adsorption.[423] This paper states that addition of alumino silicates, in the form of coal fly ash, is an "industry proven method of removing [potassium] aerosols from flue gases."[424] Other options to address this concern (aside from tail-end SCR that requires reheating of the flue gas) include the coating SCR monoliths with a protective layer and the use of potassium tolerant SCR catalysts.[425] Ecology must evaluate these other options to accommodate a high dust SCR configuration, which could ultimately end up being a very cost effective and highly effective NOx control.

6. For the ESP evaluated by Cosmo for the hog fuel boiler, Cosmo included costs for property taxes and insurance.[426] Yet, as discussed above, in many cases, property taxes do not apply to capital improvements made such as air pollutant controls, and pollution controls are not necessarily considered as increasing risks to necessitate higher insurance costs.[427] Ecology must not allow NWPPA to artificially inflate costs by items that likely would not apply to pollution control installations and upgrades.

There are examples of similar emission units in the pulp and paper industry in Washington that have installed both NOx and PM controls. For example, the hogged fuel boiler at the PCA

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[420] *Id.* at O-295.
[421] *Id.*
[422] *Id.*
[423] *See* Schill, Leonhard and Rasmus Fehrmann, Strategies of Coping with Deactivation of NH3-SCR Catalysts Due to Biomass Firing, March 30, 2018, available at https://www.mdpi.com/2073-4344/8/4/135/htm and attached as Ex. 12.
[424] *Id.*
[425] *Id.*
[426] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-310 (Appendix B, Table 3a).
[427] *See*, e.g., EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80 (Equation 2.69). *See also* EPA Control Cost Manual, Section 4, Chapter 1 (SNCR), at 1-54.

Wallula Mill had a WESP installed in 2016.[428] In addition, an SNCR was installed at the WestRock Longview Power Boiler 20,[429] which appears to be a similar boiler to the hog fuel boiler at the Cosmo plant, in that the WestRock Longview Power Boiler 20 burns wood fuels (hog fuel, forest biomass, urban wood) and oil (including reprocessed fuel oil), as well as burning paper recycling residuals, primary/secondary sludge from the process wastewater treatment plant, and natural gas.[430] WestRock Power Boiler 20 is described as a "hybrid suspension grate boiler designed to fire wet biomass…."[431] Ecology should further evaluate the SNCR installed at the WestRock Longview Power Boiler 20 to determine the percent NOx removal being achieved at that unit to assess SNCR NOx removal capabilities for the hog fuel boiler at the Cosmo facility. Because a similar source has found it cost effective to install SNCR to reduce NOx emissions, that provides a strong basis to consider SNCR as a cost-effective control for the Cosmo hog fuel boiler. Note that the Title V statement of basis for the WestRock Longview plant indicates that the SNCR was installed at the WestRock Longview Power Boiler 20 to reduce NOx emissions as part of Order 8429 which allowed for higher solid fuel firing rate.[432] Thus, the SNCR was likely installed to allow the increased solid fuel firing rate at WestRock Longview Boiler 20 to "net out" of major source permitting requirements. Controls installed to net out of major source permitting requirements should be considered controls required under the Clean Air Act. Such controls provide a relevant example of a source determining it was cost-effective to install the pollution control, even if the reasoning was to avoid a more substantive Clean Air Act requirement.

# IV. Additional Facility that Ecology Should Evaluate for Regional Haze Controls

One additional facility that Ecology should evaluate for regional haze controls is the Ardagh Glass plant in Seattle, Washington. According to NPCA analysis, the Ardagh Glass facility potentially affects regional haze in 2 Class I areas.[433] NPCA previously submitted to Ecology a four-factor analysis of regional haze controls for the Ardagh Glass Plant with its February 16, 2021 comment letter to Ecology for the informal comment period,[434] but Ecology has not responded to those comments in the public review draft regional haze plan for the second implementation period.

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[428] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-14.

[429] *Id.*

[430] Washington Department of Ecology, Statement of Basis for Air Operating Permit 0000078, WestRock Longview, December 15, 2020, at 42, available at https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Industrial-facilities-permits/WestRock-Longview.

[431] *Id.*

[432] *Id.* at 43.

[433] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.

[434] *See* NPCA, Comments Submitted for Informal comment period: Regional Haze SIP Revision - 2nd 10-Year Plan, February 16, 2021, at 11.

Ecology's air emissions inventory for the Ardagh Glass Plant identifies the following emissions for 2014-2019 at the plant.

**Table 11. Ardagh Glass Plant Emissions, 2014 to 2019**[435]

| Year | NOx, tpy | SO2, tpy | PM10, tpy |
|---|---|---|---|
| 2014 | 172.1 | 105.9 | 73.2 |
| 2015 | Not reported | Not Reported | Not Reported |
| 2016 | 153.7 | 98.7 | 95.3 |
| 2017 | 153.3 | 98.7 | 88.2 |
| 2018 | 167.6 | 89.9 | 82.2 |
| 2019 | 172.7 | 56.7 | 66.5 |

The largest sources of emissions at a glass plant are the fossil fuel-fired furnaces which melt glass. At the Ardagh plant, there are five furnaces. No. 1 is an all-electric furnace; No. 2, No. 3 and No. 5 furnaces are oxy-fuel fired; and No. 4 is an end-port regenerative furnace. The Furnace No. 1 does not have reported emissions. Furnaces Nos. 2, 3 and 5 are oxy-fuel fired. This combustion technique should reduce the formation of NOx. Furnace No. 5 is equipped with a Tri-Mer Cloud Mist Scrubber, which should capture the SO2 and PM emissions.

At the request of NPCA, Steve Klafka of Wingra Engineering, evaluated the use of ceramic catalytic filtration systems at Furnaces 2, 3, 4, and 5 of the Ardagh Glass Plant.[436] This is the same pollutant control technology discussed in Section II.C. above for the Ash Grove Cement Plant. The Klafka Report discusses how ceramic catalytic filtration systems have been used at existing glass plants as a highly effective multi-pollutant control technology.[437] The Klafka Report included a cost analysis for ceramic catalytic filtration systems at the Ardagh Glass Plant furnaces to reduce NOx and also SO2 and PM10. Table 12 below summarizes the results of his analysis.

[435] Data from Ecology's Point Source Emissions Inventory available at https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Air-emissions-inventory.
[436] *See* January 27, 2021 Four-Factor Reasonable Progress Analysis for the Ardagh Glass plant in Seattle, Washington, done by Wingra Engineering, S.C., attached as Ex. 9.
[437] *Id.* at 9.

**Table 12 - Cost Effectiveness for a Catalytic Ceramic Filter System to Control Actual and Potential Emissions from the Ardagh Glass Plant Furnaces**[438]

| Basis | Based on 2014 Actual Emissions | Based on Potential Emissions |
|---|---|---|
| Capital Costs | $11,866,967 | $16,468,204 |
| Annual Operating Costs | $330,980 | $700,622 |
| Annual Capital and Operating Costs | $1,451,222 | $2,255,220 |
| NOx Removed (tpy) | 155 | 618 |
| SO2 Removed (tpy) | 79 | 217 |
| PM Removed (tpy) | 70 | 173 |
| Total NOx, SO2 and PM Removed (tpy) | 304 | 1,008 |
| Cost Effectiveness ($ per Total Tons Removed) | $4,766 | $2,238 |

The Klafka Report indicated that it would take twelve months to construct and install a ceramic catalytic filtration system at Ardagh Glass.[439] The Klafka Report did not identify issues with energy or non-air environmental impacts of the control because the cost analysis took into account the costs of electricity, assumed use of aqueous ammonia, and the cost for 100% of the dust due to the use of hydrated lime for SO2 control.[440] The Klafka report did discuss how glass furnaces need to be rebuilt every 10-20 years, but it did not find such a rebuilding of the furnace would limit the remaining useful life of the glass plant because it has been in that location since 1931.[441] The Klafka Report concluded that it is technically feasible to add a catalytic ceramic filtration system to the glass furnaces at Ardagh Glass and that it would be very cost effective to do so, at a cost per total tons of pollutant removed of $4,766/ton based on emission reductions from 2014 actual emissions and at a cost of $2,238/ton based on emission reductions from potential emissions.[442]

Thus, a ceramic catalytic filtration system is a very cost effective control that can significantly reduce emissions from the Ardagh Glass Plant, and Ecology should strongly consider this control at Ardagh Glass as part of its regional haze control strategy.

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[438] *Id.* at 11.
[439] *Id.* at 10.
[440] *Id*. at 11.
[441] *Id.* at 11-12.
[442] *Id.* at 12. Note that the narrative discussion of the Klafka report indicates lower cost effectiveness numbers of $3,768/ton for reductions from 2014 emissions and $1,819/ton from reductions in potential emissions, but Table 5 of the report indicates a higher cost per ton of pollutants removed. The Table 5 data of the Klafka Report is included in Table 12 of this report as the data are assumed to be the more accurate numbers.

# Review and Comments on
# Washington Department of Ecology's
# Draft Regional Haze Plan for the Second Implementation Period:
# Long Term Strategy and Four-Factor Analysis of Controls

By Victoria Stamper

November 19, 2021

Prepared for
National Parks Conservation Association

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The Clean Air Act's regional haze provisions require states to adopt periodic, comprehensive revisions to their implementation plans for regional haze on 10-year increments to achieve reasonable progress towards the national visibility goal. The plan revision for the second implementation period was due to be submitted to EPA by July 31, 2021.[1] As part of the comprehensive revisions to their regional haze plan, states must submit a long-term strategy that includes enforceable emission limits and other measures as may be necessary to make reasonable progress towards the national visibility goal.[2]

To that end, in October of 2021, the Washington Department of Ecology (Ecology or WDOE) made available its plan for addressing reasonable progress toward the national visibility goal for Class I areas.[3] Ecology has proposed to include requirements for five facilities in its regional haze plan: the TransAlta Centralia Plant, the Ash Grove Cement Plant, the Cardinal FG Winlock Glass Plan, the Intalco Aluminum Plant, and the Alcoa Wenatchee Plant. However, the Agreed Orders, Consent Decree, and Permits that it has included in its proposed Long Term Strategy primarily rely on control requirements the owners already planned to meet under other Clean Air Act requirements (including under the first round regional haze plan) or reflect a commitment to conduct a four factor analysis of controls if/when a currently shutdown plant begins operations. In other words, Ecology's draft regional haze plan for the second implementation period does not include any additional regional haze control requirements for industrial sources of regional haze pollution beyond what was already required and on the books.

There are several other facilities that met Ecology's criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period for which Ecology is not currently proposing to adopt any new controls as part of its second round regional haze plan. Yet, there are pollution controls (primarily for nitrogen oxides (NOx)) that Ecology found could be cost effectively installed at these sources to significantly reduce emissions of the visibility-impairing pollutants. Ecology has indicated that it will address these sources in a subsequent revision to its regional haze plan. In other words, Ecology's regional haze plan for the second implementation period is not complete.

The four factors that must be considered in determining appropriate emissions controls for the second implementation period are as follows: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any source being evaluated for controls.[4] EPA states that it anticipates the cost of controls being the predominant factor in the evaluation of reasonable

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[1] 40 C.F.R. §51.308(f).
[2] 40 C.F.R. §51.308(f)(2)(i); 42 U.S.C. § 7491(b)(2). Under the Clean Air Act, state implementation plans must include "include enforceable emission limitations and other control measures, means, or techniques . . . , as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter." 42 U.S.C. § 7491(a)(2)(A). An emission limitation is a "requirement" that "limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." *Id*. § 7602(k).
[3] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021.
[4] 40 C.F.R. §51.308(f)(2)(i).

progress controls and that the other factors will either be considered in the cost analysis or not be a major consideration.[5] Such is the case with the add-on controls evaluated in this report. Specifically, the remaining useful life of a source is taken into account in assessing the length of time the pollution control will be in service to determine the annualized costs of controls. If there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution controls is generally considered the remaining life of the source.[6] In addition, costs of energy for selective noncatalytic reduction (SNCR), selective catalytic reduction (SCR), and other controls at a particular source are considered in determining the annual costs of these controls, which means that the bulk of the non-air quality and energy impacts are generally taken into account in the cost effectiveness analyses as is the remaining useful life of a unit. With respect to the length of time to install controls, that is not generally an issue for SCR or SNCR which can and have been installed within three to five years of promulgation of a requirement to install such controls.[7] In any event, EPA's August 20, 2019 regional haze guidance states that, with respect to controls needed to make reasonable progress, the "time necessary for compliance" factor does not limit the ability of EPA or the states to impose controls that might not be able to be fully implemented within the planning period; more specifically, when considering the time necessary for compliance, a state may not reject a control measure because it cannot be installed and become operational until after the end of the implementation period."[8]

This report comments on the proposed Long Term Strategy and on Ecology's review of the four-factor analyses of pollution controls that were submitted for facilities in Washington.

## I. Background.

Ecology used 2014 emissions data and Q/d (i.e., the ratio of a source's visibility-impairing emissions in tons per year (Q) divided by the source's distance from the nearest Class I area (d)) to identify sources to prioritize for evaluation of regional haze controls for its plan for the second implementation period. Ecology based on their review only on major sources. Ecology did not explain whether it focused on major sources based on the actual emissions of each source or based on the potential emissions of each source, and that should be clarified. Ecology used a

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[5] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 37.

[6] *Id.* at 33. While we are aware that some EGUs evaluated in this report have planned decommission dates, we are not aware that any of those dates are enforceable. Thus, for all of the EGUs evaluated for add-on NOx controls in this report, we assumed that the expected useful life of the pollution control being evaluated was the remaining useful life of the source, as directed to by EPA in its August 2019 guidance.

[7] For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan.

[8] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 41 (it would be inconsistent with the regional haze regulations to discount an otherwise reasonable control "simply because the time frame for implementing it falls outside the regulatory established implementation period.").

Q/d value of 10 or higher as a cutoff for selecting major sources and included two other facilities with a lower than 10 Q/d value because they were in a selected source category. Based on this analysis, Ecology came up with the following list of sources to evaluate for controls.

**Table 1. WDOE's List of Sources to Conduct a Four-Factor Analysis of Controls**[9]

| Facility Site Name | Q (tons of NOx, PM10, SO2, and NH3) | D (km) to nearest Class I area | Q/d | Nearest Class I Area | Number of Class I Areas Impacted (NPCA Analysis)[10] | Source Category |
|---|---|---|---|---|---|---|
| TransAlta Centralia Generation LLC | 10,749.4 | 71.8 | 149.8 | Mount Rainier NP | | Coal-powered electric |
| McKinley Paper Company | 367.2 | 4.4 | 83.1 | Olympic NP | 1 | Pulp and Paper Plant |
| Alcoa Primary Metals Wenatchee Works | 3,461.7 | 42.8 | 80.9 | Alpine Lakes WA | | Alumina Refining and Aluminum Production |
| Alcoa Primary Metals Intalco Works | 5,658.5 | 78.9 | 71.7 | North Cascades NP | 38 | Alumina Refining and Aluminum Production |
| BP Cherry Point Refinery | 2,945.1 | 80.8 | 36.4 | North Cascades NP | 14 | Petroleum refineries |
| Tesoro Northwest Company | 2,312.3 | 75.4 | 30.7 | Olympic NP | 10 | Petroleum refineries |
| WestRock Tacoma | 1,353.7 | 48.4 | 27.9 | Mount Rainier NP | 10 | Pulp, Paper, and Paperboard Mills |

[9] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 161-162.

[10] Based on NPCA's Regional Haze Fact Sheet for Washington, Sources of Visibility Impairing Pollution in Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view. Note that neither the TransAlta Centralia power plant nor the Alcoa Wenatchee plant were included in NPCA's evaluation, presumably because of TransAlta's prior requirement to decommission the Centralia coal-fired power plant by 2025 and because the Alcoa Wenatchee plant has been shut down since 2015. Note that in the NPCA fact sheet, the Weyerhauser NR Company plant is now the Nippon Dynawave plant, and the Boise Paper facility is now the Packaging Corp. of America plant. Note that the U.S. Oil refinery in Tacoma is not in NPCA's Fact Sheet.

| Facility Site Name | Q (tons of NOx, PM10, SO2, and NH3) | D (km) to nearest Class I area | Q/d | Nearest Class I Area | Number of Class I Areas Impacted (NPCA Analysis)[10] | Source Category |
|---|---|---|---|---|---|---|
| Nippon Dynawave Packaging Company | 2,656.0 | 104.8 | 25.3 | Mount Adams WA | 21 | Paperboard Mills |
| Puget Sound Refining Co. (Shell) | 1,793.1 | 73.0 | 24.5 | Olympic NP | 8 | Petroleum Refineries |
| Pt Townsend Paper Corp. | 848.0 | 35.0 | 24.2 | Olympic NP | 5 | Paper (not Newsprint) Mills |
| Ash Grove Cement Co., E Marginal | 1,243.6 | 53.8 | 23.1 | Alpine Lakes WA | 9 | Cement Manufacturing |
| Cosmo Specialty Fibers, Inc. | 973.8 | 58.2 | 16.7 | Olympic NP | 5 | Paperboard Mills |
| WestRock Longview, LLC | 1,574.2 | 100.7 | 15.6 | Mount Adams WA | 10 | Paperboard Mills |
| Georgia-Pacific Consumer Operations LLC | 653.0 | 45.4 | 14.4 | Mount Hood WA | 5 | Paper (except Newsprint) Mills |
| Phillips 66 | 840.6 | 77.2 | 10.9 | North Cascades NP | 5 | Petroleum Refineries |
| Cardinal FG Winlock | 859.8 | 80.1 | 10.7 | Mount Rainier NP | 6 | Flat Glass Manufacture |
| Packaging Corp. of America (PCA), Wallowa | 1,048.3 | 111.5 | 9.4 | Eagle Cap WA | 16 | Paperboard Mills |
| U.S. Oil & Refining Co. | 149.2 | 46.4 | 3.2 | Mount Rainier NP | | Oil Refinery |

Of the above list, there were a few sources for which Ecology did not request a four-factor analysis of controls for, because "[s]ome of these facilities had existing legal requirements or pending permit actions to reduce emissions."[11] Those facilities were the TransAlta Centralia power plant, the Cardinal FG Winlock glass plant, and the Ash Grove Cement Plant.[12] Ecology also will only request a four-factor analysis of controls for the Intalco Aluminum Plant and the Alcoa Wenatchee Aluminum Plant if the plants restart operations.[13] In addition, it appears that Ecology did not request a four-factor analysis of controls for the McKinley Paper Company located near Port Angeles, and Ecology's draft regional haze plan does not mention this facility other than to show its Q/d value of 83.1 (making it the facility with the second highest Q/d value).[14]

Its Long Term Strategy addresses the Centralia Power Plant, Intalco and Alcoa Wenatchee Aluminum plants, the Ash Grove Cement Plant, and the Cardinal FG Winlock Glass Plant, although it does not require additional pollution control measures other than what was already required for these facilities. This is discussed in Section II below.

For the remaining facilities for which Ecology requested four-factor analyses of controls, Ecology selected the refineries as the first priority of sources to focus on for regional haze controls. Ecology's reasons for prioritizing the refineries included the following:

- Four of the five refinery facilities are located in the Puget trough, west of several Class 1 Areas. Their cumulative regional haze causing emissions influence the same Class 1 Areas.

- Predominant winds direct the emissions from the refineries toward several Class 1 Areas.

- The refineries' potential emission reductions of 4,200 tons per year account for the vast amount of potential emission reductions.

WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 166.

Ecology prioritized pulp and paper mills lower than refineries because they "are not located as close to each other as the refineries so they do not have as great of a cumulative effect."[15] Ecology also states that the potential reduction in regional haze emissions from pulp and paper mills is "vastly less than the potential refinery emission reductions."[16]

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[11] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 163.
[12] *Id.* at 212.
[13] *Id.* at 178, 180-181.
[14] Note that the Technical Support Document for the current operating permit for the McKinley Plant states that the McKinley facility was purchased from Nippon Paper Industries USA Co. in 2017. *See* https://www.orcaa.org/wp-content/uploads/TSD_McKinley_Final_17August2021.pdf. This is a different facility than the Nippon Dynawave facility that is located in Longview, Washington.
[15] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 166.
[16] *Id.* at 167.

The regional haze plan regulations require states to include a description of the criteria that it used to determine the sources or groups of sources that it evaluated for controls,[17] which Ecology has done in its draft regional haze plan. As stated above, it selected sources with a Q/d value equal to or greater than 10. EPA's July 8, 2021 guidance memo states that "[u]nder the [regional haze rule], each state has an obligation to submit a long-term strategy that addresses the regional haze visibility impairment resulting from emissions from within that state."[18] While states have the discretion to select any reasonable source selection methodology, the source selection methodology must "produce a reasonable outcome."[19] In the case of Ecology's source selection process and four factor analyses, the outcome of its approach as proposed in the draft regional haze plan is a long term strategy that does not include any control measures other than those control measures that were either previously imposed to meet best available retrofit technology (BART), i.e., at the TransAlta Centralia Plant, that were already required under other requirements, i.e., Ash Grove Cement Plant, that were voluntarily proposed by the source due to an increase in capacity (i.e., Cardinal FG Winlock Glass Plant), or that simply require the submittal of a four-factor analysis of controls if the currently "curtailed" plants start operating again (Intalco Aluminum and Alcoa Wenatchee). Ecology's selection of sources to include in its long term strategy ignored the fact that Ecology has found cost effective control options for several sources identified in Table 1 above. Ecology states that it must follow its reasonably available control technology (RACT) rule requirements before it can establish legally establish control requirements.[20] Given that the regional haze pollution controls are required to be part of the regional haze plan pursuant to 40 C.F.R. 51.308(f)(2)(i), Ecology's regional haze plan for the second implementation period is not yet complete or it otherwise fails to meet the requirements for regional haze plans. Given that Ecology's Public Review Draft is stated to be its State Implementation Plan (SIP) revision for the second regional haze plan implementation period of 2018 to 2028, it will be assumed for the purpose of these comments that the Public Review Draft is the complete plan to be submitted to EPA for approval. This report provides comments and analyses on the source-specific requirements of Ecology's proposed Long Term Strategy of the Public Review Draft and also on the other sources evaluated for control by Ecology in the context of its regional haze plan for the second implementation period.

[17] 40 C.F.R. 51.308(f)(2)(i).
[18] July 8, 2021 EPA RHR Clarifications Memo at 3. See also 40 C.F.R. 51.308(f)(2).
[19] *Id.*
[20] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 163.

## II. Review and Comments on Ecology's Proposed Long Term Strategy Source-Specific Control Measures

Ecology lists the following source-specific emission limits and shutdowns of its long term strategy:

- TransAlta Centralia Generation BART order revision, which ceased coal-fired operation of one boiler in December 2020 and will cease coal-fired operation of the other boiler by the end of 2025.

- Cardinal FG Winlock Glass Plant, which voluntarily requested a permit to install selective catalytic reduction (SCR) on its glass furnace in conjunction with an increase in glass production capacity. A permit was issued authorizing these actions on February 11, 2001, and Ecology states that the SCR should be installed and operating by 2022.

- Ash Grove Cement Company, which entered into a Consent Decree in 2013 with EPA, Ecology, and other state agencies that required optimization of the Seattle Kiln to reduce NOx emissions and is currently subject to a NOx limit of 5.1 pounds per ton ("lb/ton") of clinker.

- Alcoa Wenatchee and Intalco Aluminum, which are both currently in "curtailment due to market conditions," for which ECOLOGY has proposed Agreed Orders to require the plants to conduct and submit a four-factor analysis of controls if they decide to restart operations.[21]

### A. TransAlta Centralia Generation

The TransAlta Centralia Generating Station is a coal-fired power plant located near Centralia, Washington. In its 2010 Regional Haze SIP, Ecology indicated that the Centralia plant significantly impacts regional haze in twelve Class I areas in Washington and Oregon.[22] The Centralia power plant was subject to BART in Washington's regional haze plan. In 2003, EPA approved requirements applicable to the Centralia units' SO2 and PM emissions as meeting BART.[23] In 2012, EPA approved a NOx BART determination in First Revised BART Order 6426 for the Centralia power plant, which included the following control requirements: an initial NOx emission limitation of 0.21 lb/MMBtu for each unit based on the installation of SNCR on both coal-fired units plus Flex Fuel followed by an optimization study and lowering of the

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[21] *Id.* at 212.

[22] WDOE, Regional Haze Plan, December 2010, at 11-13 (Table 11-11), available at https://apps.ecology.wa.gov/publications/documents/1002041.pdf.

[23] *See* 68 Fed. Reg. 34821 (June 11, 2003).

emission limits based on the study results.[24] In addition, the BART order required each of the two Centralia units to cease burning coal and be "decommissioned" by December 31, 2020 for one unit and by December 31, 2025 for the other unit, unless Ecology determined that state or federal law requires selective catalytic reduction (SCR) to be installed on either unit.[25] In 2021, EPA approved a revision to the BART requirements for the Centralia power plant.[26] Specifically, TransAlta had installed a Combustion Optimization System with Neural Network program (Neural Net) to decrease ammonia slip from the SNCR, and such Neural Net controls also help to reduce NOx emissions among other things. Ecology reduced the NOx limit applicable to one unit from to 0.18 lb/MMBtu and changed other requirements pertaining to use and monitoring of ammonia and analyzing coal sulfur and nitrogen content.[27] Ecology also eliminated the requirement in the BART Order 6426 that required that the units be "decommissioned" once they stopped burning coal, based on 2017 changes to a Memorandum of Agreement between TransAlta and the state of Washington.[28] As EPA states "[t]he 2017 MOA makes clear that TransAlta is not precluded from the possibility of retrofitting the facility to natural gas, or other non-coal energy source, as long as it meets the statutory requirements of Chapter 80.80 RCW."[29] This state statute addresses greenhouse gas emissions from baseload electric generating plants.[30]

Ecology's Technical Support Document for its 2020 BART SIP revision states that "Ecology is aware that if TransAlta repowers the units on natural gas the visibility improvements anticipated by the current BART order and state implementation plan limits would not be met. Repowering would change the emission reduction used in determining the 2028 further progress goals for the nearby Class I Areas (Mt. Rainier and Olympic National Parks, and the Goat Rocks and Alpine Lakes Wilderness Areas) under the 2021 Regional Haze State Implementation Plan." It would also change the emission reductions used in determining the 2028 reasonable progress goals for several Oregon Class I areas. In its 2010 Regional Haze SIP, Washington identified twelve Class I areas where the Centralia Power Plant had an impact greater than or equal to 0.5 deciviews (dvs). Thus, if the Centralia units repowered to natural gas, it could significantly affect the reasonable progress goals for all of those Class I areas, which are listed in Table 2.

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[24] *See* 77 Fed. Reg. 72742(12/6/2012). *See also* First Revised BART Order 6426, attached as Ex. 1.
[25] *See* 77 Fed. Reg. 72742(12/6/2012). *See also* First Revised BART Order 6426, available at Ex. 1.
[26] 86 Fed. Reg. 24502 (May 7, 2021).
[27] Ecology, Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision, July 2020, at i (attached as Ex. 2).
[28] As discussed in 86 Fed. Reg. 13256 at 13258 (Mar. 8, 2021)
[29] 86 Fed. Reg. 13258 (Mar. 8, 2021).
[30] See Chapter 80.80 RCW, available at https://app.leg.wa.gov/rcw/default.aspx?cite=80.80.

**Table 2. Washington and Oregon Class I Areas Where Ecology Modeled Significant Visibility Impacts from the Centralia Power Plant in its 2010 Regional Haze SIP**.[31]

| |
|---|
| Alpine Lakes Wilderness (WA) |
| Glacier Peak Wilderness (WA) |
| Goat Rocks Wilderness (WA) |
| Mt. Adams Wilderness (WA) |
| Mt. Hood Wilderness (OR) |
| Mt. Jefferson Wilderness (OR) |
| Mt. Rainier National Park (WA) |
| Mt. Washington Wilderness (OR) |
| North Cascades National Park (WA) |
| Olympic National Park (WA) |
| Pasayten Wilderness (WA) |
| Three Sisters Wilderness (OR) |

In its Technical Support Document for its 2020 BART SIP revision, Ecology states "[i]f TransAlta decides to switch to non-coal power generation, a Notice of Construction application would need to be submitted to Southwest Clean Air Agency by the company. Ecology would require the company to do, at a minimum, emissions modeling that would be required under the BART process to quantify the visibility impacts resulting from the operation as a natural gas boiler plant (EGU)."[32] It appears that Ecology may have been stating that it would evaluate whether the Centralia plant, powered with a fuel other than coal, would be subject to BART or subject to additional control requirements, by evaluating what the impacts of the plant would be on visibility in Class I areas. But the Centralia plant was already determined to be subject to BART.[33] Applicability to BART would not change if either or both units were repowered to natural gas or some other fuel.[34]

Ecology's draft regional haze plan for the second implementation period does not address the possibility that one or both the Centralia units could be allowed to repower with a fuel other than coal under the revised 2020 BART Order. In fact, Ecology states that the 2028 "on the books" emissions of SO2 and NOx will decrease significantly when coal-fired power production ceases at TransAlta.[35] Ecology also makes clear in its draft regional haze plan that it set Centralia's 2028 emissions to zero based on the facility ceasing coal-fired energy production by 2020 for one unit and by 2025 for the other unit.[36] Ecology identifies the cessation of coal-firing at the

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[31] 2010 Washington Regional Haze State Implementation Plan at 11-13 (Table 11-11), available at https://apps.ecology.wa.gov/publications/documents/1002041.pdf.
[32] Ecology, Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision, July 2020, at 3 (Ex. 2).
[33] 2010 Washington Regional Haze State Implementation Plan at 11-13 (Table 11-9), available at https://apps.ecology.wa.gov/publications/documents/1002041.pdf.
[34] *See*, e.g., 77 Fed. Reg. 39425 at 39429 (July 3, 2012).
[35] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 77-78.
[36] *Id.* at 82 and at 176.

Centralia units as a "shutdown schedule" control and as part of its Long Term Strategy.[37] Yet, if the Centralia units could lawfully be repowered with natural gas or another fuel, which Ecology has made clear in its 2020 Technical Support Document for its BART order revision could occur, then its assumption of zero emissions in 2028 from the Centralia Power Plant is significantly flawed. EPA has said if a state is going to rely on a source shutdown in its regional haze plan, the shutdown needs to be federally enforceable.[38] Thus, Ecology needs to make federally enforceable the decommissioning of the Centralia Generating Station's coal-fired units in its SIP and issue a revised Order, as was required in the Order prior to the 2020 revisions.

In its 2020 Technical Support Document for the 2020 BART Revision, Ecology explains some of the requirements that would apply if the Centralia units repowered to natural gas or another fuel. For example, Ecology states that under Chapter 80.80 RCW that sets greenhouse gas emission limits reflective of combined cycle combustion turbines, TransAlta would need to take an enforceable limit to keep operations annually below a 60% capacity factor to avoid being classified as a baseload power plant under Chapter 80.80 RCW which would require that the facility meet GHG emission limits.[39] Ecology ignores the possibility that the units could be repowered to a natural gas-fired combined cycle power plant by retaining the steam turbine but replacing the coal boiler with a gas-fired combustion turbine and a heat recovery steam generator, in which case it could likely meet the GHG emission limit of Chapter 80.80 RCW and thus be allowed to operate at higher capacity factors.

Ecology also states that if TransAlta decided to switch to non-coal fired power generation, they would have to submit a Notice of Construction application to the Southwest Clean Air Agency and that Ecology would "require the company to do, at a minimum, emissions modeling that would be required under the BART process to quantify the visibility impacts resulting from the operation as a natural gas boiler plant (EGU)."[40] Neither the modeling nor the requirement to obtain a construction permit would guarantee that any specified level of emissions reduction would be required if the units were repowered with another fuel such as natural gas because it depends on how applicability to emissions control requirements such as best available control technology (BACT) would be determined.

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[37] *Id.* at 212.

[38] *See* U.S. EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period, July 8, 2021, at 10 ("[O]n the way measures, including anticipated shutdowns that are relied on to forgo a four-factor analysis or shorten the remaining useful life of a source, are necessary to make reasonable progress and must be included in a SIP."). *See also*, e.g., 11/1/2021 EPA letter to Wyoming Department of Environmental Quality, Comments on Draft Wyoming State Implementation Plan Regional Haze Round Two, at 5 ("If the State is relying on the source shutdowns as part of its long-term strategy for making reasonable progress, Wyoming must make these planned retirements enforceable in the SIP. Similarly, if the State is relying on the source shutdowns to forgo conducting a four-factor analysis because a shutdown is effectively the most stringent control available, the shutdown must be in the SIP.)

[39] Ecology, Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision, July 2020, at 6-7 (Ex. 2).

[40] *Id.* at 3.

An estimate of what the NOx emissions could be assuming a conversion of the existing boilers from coal to natural gas can be made based on the following assumptions:

- Assume same generating capacity with gas of 670 MW
- Assume slightly higher hourly heat input with natural gas, based on Energy Information Administration data that shows the average heat rate of a natural gas-fired steam generation is 10,416 Btu/kW-hr as compared to the average heat rate of a coal-fired steam generator of 10,142 Btu/kW-hr[41] (meaning the heat input per hour would be 2.7% higher for natural gas firing, assuming the same generating capacity could be achieved with natural gas). Thus, assuming a coal-fired heat rate of 10,142 Btu/kW-hr, the hourly heat input to each boiler with coal would be approximately 6,795 MMBtu/hour, and the maximum hourly heat input to each boiler with natural gas would be 2.7% higher or 6,979 MMBtu/hour.

Using AP-42 emission factors and assuming that the burners would continue to be low NOx burners, the NOx emission factor for the boilers would be 140 lb per MMscf, which equates to approximately 0.14 lb/MMBtu.[42] If the units had to be limited to 60% capacity factor to avoid the GHG emission limits of Chapter 80.80 RCW, the potential NOx emissions of each Centralia unit repowered to natural gas would be 2,568 tons per year per unit or 5,135 tons per year total. In comparison, the NOx emissions from the two Centralia units per 2018-2020 averaged about 3,300 tons per year per unit or 6,600 tons per year when both units were operating. Thus, while repowering the Centralia units from coal to gas would reduce emissions from the units, it would not by any means eliminate the regional haze pollutants from the units as was required in the first planning period SIP and was assumed for the plant in the reasonable progress goals determination and in the modeling of the Long Term Strategy for this second planning period SIP.

It appears that TransAlta has been pursuing a coal-to-gas conversion program at some of its other units in Canada.[43] Thus, Ecology cannot just dismiss the possibility of repowering the Centralia units as unlikely. For these reasons, Ecology needs to specifically require the decommissioning of the Centralia Generating Station's coal-fired units to be consistent with its proposed Long Term Strategy and its determination of reasonable progress goals. Failing that, Ecology must include the expected emissions from a re-powered Centralia Power Plant in its 2028 modeling and determination of reasonable progress goals and advise nearby states of the changes in 2028 emissions from the facility so that they also revise their Class I area reasonable progress goals.

### B. Alcoa Primary Metals Intalco Works and Alcoa Wenatchee

The Alcoa Primary Metals Intalco Works Plant (Intalco Plant) is an aluminum smelter located in Ferndale, Washington. In its 2010 Regional Haze SIP, Ecology indicated that the Intalco plant

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[41] *See* https://www.eia.gov/electricity/annual/html/epa_08_02.html.
[42] EPA, AP-42, table 1.4-1.
[43] https://www.nsenergybusiness.com/features/coal-gas-conversion-us-canada/.

significantly impacted regional haze in seven Class I areas in Washington.[44] NPCA has found that the Alcoa Intalco plant potentially impacts up to 42 Class I areas and that it is the most significant industrial contributor to regional haze at North Cascades National Park.[45] Ecology states that the Intalco Plant has been under curtailment since 2020.[46]

The Alcoa Wenatchee Plant is an aluminum smelter located in Wenatchee, Washington. As shown in Table 1 above, the Wenatchee plant has a Q/d value of 80.9 based on 2014 emissions. According to NPCA's analysis, emissions from the Wenatchee plant potentially impact 34 Class I areas, including the Alpine Lakes Wilderness area,[47] located approximately 28 miles west of the facility, and also North Cascades National Park to the northwest and Mount Rainier National Park to the southwest.[48] Ecology states that the Wenatchee plant has been in curtailment since 2015.[49]

Washington's 5-year regional haze progress report acknowledged that the SO2 emissions from Intalco and, to a lesser extent the Wenatchee facility, create a challenge to additional visibility improvement in North Cascades and Olympic National Park.[50] Thus, Ecology is including the Intalco plant and the Wenatchee plant as part of its Long Term Strategy for the regional haze plan for the second implementation period.[51] These plants have the third and fourth highest Q/d values based on 2014 emissions, and Ecology has acknowledged that the plants would contribute to regional haze if the plants restarted operations.[52] However, Ecology's Long Term Strategy does not specify any controls to be installed at these plants if operations resume.

Ecology has developed Agreed Orders 18100 and 18216 that require these plants to complete a four-factor analysis of controls prior to startup, if either plant decides to restart.[53] The Agreed Orders require that Alcoa submit four-factor analyses at least 180 days before restarting any of the facilities' potlines, and the analyses must be based on permitted emission limits (not the recent past years of zero to very low emissions). Compliance with any controls identified in the four-factor analyses would not be required until three years after Ecology's approval of the four-factor analyses. However, the Agreed Orders do not set any deadline for Ecology to approve the four-factor analyses, nor do they define the process that would be followed for Ecology to grant approval. The Agreed Orders also do not spell out what the public review and input process would be. Moreover, the Agreed Orders allow Alcoa or Ecology "to request a change to the

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[44] WDOE, Regional Haze Plan, December 2010, at 11-10 (Table 11-6), available at https://apps.ecology.wa.gov/publications/documents/1002041.pdf.
[45] NPCA, Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), at 3.
[46] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 82.
[47] 78 Fed. Reg. 79344, 79348-79349. (Dec. 30, 2013).
[48] NPCA, Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), at 3.
[49] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 82.
[50] WDOE, "Washington State Regional Haze 5-Year Progress Report," at 213, (Sept. 2017), https://www.regulations.gov/document?D=EPA-R10-OAR-2018-0001-0004. (Progress Report)
[51] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 212.
[52] *Id.* at 82.
[53] *Id.*

conditions" of each Order by submitting a written request to the other party.[54] Thus, these requirements of the Agreed Orders, which do not in and of themselves require implementation of any control measures, could be modified via a written request by Alcoa. These Agreed Orders cannot be considered to suffice for the four-factor analyses and control measures that Ecology states are needed in the event the plants start up again. Instead, Ecology must conduct four-factor analyses for these plants now based on permitted emission rates, so Alcoa is on notice as to the control requirements it must meet before it decides whether to restart either plant. Alternatively, Ecology should revoke the plants' operating permits and require each plant to go through major source new source review permitting before restarting operations.

Ecology states that if it conducted a four-factor analysis on the Intalco planta and the Wenatchee plant now, controls would not be cost effective because the plants have extremely low emissions due to being "in curtailment."[55] However, Ecology has not revoked either plants' permits, and Ecology states the plants could restart at any time.[56] Further, Ecology has included both plants' emissions in its 2028 emissions inventory, and both plants' emissions are reflected in the reasonable progress goals.[57] Thus, Ecology is without justification to claim that it can delay conducting a four-factor analysis and imposing control requirements because controls based on current emissions would not be cost effective. Just as EPA requires forthcoming source shutdowns to be enforceable in order for a state to take into account a shortened remaining useful life in a four-factor control analysis, states cannot take into account significantly reduced emissions to determine no controls are cost effective without making such assumptions enforceable.[58] This is particularly true for the two aluminum plants, for which Ecology states could restart at any time under their existing permits and for which Ecology claims controls would be needed to address regional haze impacts if these sources restart.

With respect to the Intalco Plant, Alcoa had previously agreed to complete a Notice of Construction application for the installation of a wet scrubber.[59] That wet scrubber was required to address the area's noncompliance with the 1-hour SO2 National Ambient Air Quality Standard (NAAQS). However, according to Ecology, once Alcoa decided to curtail operations of the Intalco plant, the requirement to install a scrubber became null and void.[60]

Since the Intalco plant has curtailed operations and emissions have essentially been close to nil, the 1-hour SO2 ambient air concentrations in the area have decreased considerably. The table below presents the 99$^{th}$ percentile 1-hour average SO2 values from the two ambient air SO2 monitors in Whatcom County: One that is located at the same address as the Intalco Plant (4050 Mountain View Road, Ferndale) and the other that is located 0.5 miles away from the Intalco

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[54] *See* Section V Agreed Order Nos. 18100 and 18216 in Appendix Q of WDOE Public Review Draft, Second Regional Haze Plan, October 2021.
[55] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 177-180.
[56] *Id.*
[57] *Id.* at 82, 84-86, and 176.
[58] *See* U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 17, 20. *See also* U.S. EPA, Clarification Regarding Regional Haze Plans for the Second Implementation Period, July 8, 2021, at 12.
[59] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 179. *See also* Agreed Order 16449.
[60] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 179.

Plant (6036 Kickerville Road, Ferndale). EPA has indicated that both of these monitoring sites were established to characterize air quality around the Intalco plant.[61] For comparison, compliance with the 1-hour SO2 NAAQS of 75 parts per billion (ppb) is based on the three-year average of the 99$^{th}$ percentile of the daily maximum 1-hour average SO2 concentration.[62]

**Table 3. 99$^{th}$ Percentile 1-hour SO2 Concentrations in Whatcom County, 2017 to 2021**[63]

| Year | Monitor Location | 99$^{th}$ Percentile 1-hour SO2 Concentration, ppb | Observations, 1-hour |
|---|---|---|---|
| 2017 | 6036 Kickerville Road, Ferndale, WA | 70 | 7884 |
| 2018 | | 74 | 8087 |
| 2019 | | 70 | 7688 |
| 2020 | | 59 | 8133 |
| 2021 | | 2 | 4083 |
| 2017 | 4050 Mountain View Rd, Ferndale, WA | 114 | 8469 |
| 2018 | | 101 | 8542 |
| 2019 | | 105 | 8535 |
| 2020 | | 62 | 8541 |
| 2021 | | 3 | 4239 |

According to Ecology, the Intalco facility began curtailing production in April 2020. The SO2 monitors around the plant showed a dramatic decrease in hourly SO2 concentrations in 2020 and 2021, compared to the three years prior. EPA designated part of Whatcom County as nonattainment for the 1-hour SO2 NAAQS effective April 3, 2021.[64] Ecology must develop and submit a nonattainment plan to EPA by October 30, 2022, which is less than a year from now.[65] Given that the SO2 emissions from the Intalco plant also are the primary contributor to regional haze, Ecology should coordinate the development of regional haze measures and 1-hour SO2 measures.

The EPA has previously found that the cost effectiveness of a lime spray forced oxidation (LSFO) scrubber at the Intalco plant would cost \$3,875/ton to \$4,363/ton in a 2012 proposed rulemaking.[66] That would equate to roughly \$4,530/ton at most in 2019 dollars.[67] Not only would those SO2 controls be cost effective at the Intalco Plant, but such controls would presumably be required in order for the Intalco Plant to restart since the area must demonstrate attainment with the 1-hour SO2 NAAQS as expeditiously as practicable and no later than April

[61] *See*, e.g., 85 Fed. Reg. 45146 at 45150 (Table 6) (July 27, 2020).
[62] 40 C.F.R. 50.17
[63] Data from EPA's Air Data Monitor Values Report for Whatcom County SO2 Monitors available at https://www.epa.gov/outdoor-air-quality-data/monitor-values-report.
[64] 86 Fed. Reg. 16055 at 16073 (Mar. 26, 2021); 40 C.F.R. 81.348.
[65] 86 Fed. Reg. 16055 at 16057, 16059 (Mar. 26, 2021). (Nonattainment plans are due within 18 months of the effective date of the nonattainment designation).
[66] 77 Fed. Reg. 76174 at 76191 (Dec. 26, 2012).
[67] Based on changes in the Chemical Engineering Plant Cost Indices (CEPCI).

2026 (i.e., five years after the effective date of the SO2 nonattainment designation).[68] Ecology states it generally takes two to three years for the design and installation of SO2 controls,[69] and it is commonly assumed that a 180 day shakedown period is needed after installation of a pollution control. Thus, to attain the SO2 NAAQS by April 2026, the permit to install the scrubber should be approved by no later than October 2023, which is less than one year away. Based on that timeframe, Ecology should require the submittal of a construction permit application to install an LSFO scrubber at the Intalco Plant now, so that the permit authorizing such controls can be issued no later than October 2023.

It has recently been reported that negotiations are underway to potentially restart the Intalco aluminum plant (possibly under a different owner) or to build a steel mill on the site.[70] Thus, with the possibility of aluminum plant operations resuming and the fact that an SO2 nonattainment plan is required for the Intalco plant area, Ecology has no reasonable justification to allow Alcoa to wait to submit its regional haze control analysis. If the Intalco plant resumes operation, the level of SO2 control that needs to be met is known and the most effective way to meet that level of control is the installation of an LSFO wet scrubber, based on the analysis EPA previously conducted for the BART evaluation and based on analyses that presumably was done by Alcoa and Ecology in the process of developing Agreed Order 16449.[71] Thus, Ecology should re-impose the requirement in Agreed Order 16449 for Alcoa to apply for a permit to construct a new scrubber at the Intalco Plant, which presumably was necessary for the Intalco plant to comply with the SO2 NAAQS. And Ecology should issue the permit for the new scrubber no later than October 2022.

For the Intalco Wenatchee plant, Ecology should not wait to decide what controls to require to address regional haze until Alcoa decides to restart the plant. Ecology must require the submittal of a four-factor analysis of regional haze controls now and propose appropriate controls as part of its regional haze plan that would apply should the plant restart. Alternatively, Ecology should revoke the permit for the Alcoa Wenatchee plant and require the facility to obtain a new source review permit as a new source if it decides to restart.

If Ecology is going to claim that controls at these two aluminum plants are necessary as part of its Long Term Strategy for the second implementation period, then the state's plan must include the requirements that would be imposed if either of the plants resume operation. Such evaluations of the emission reduction measures necessary to make reasonable progress is required to be included in the long term strategy pursuant to 40 C.F.R. 51.308(f)(2)(i). Further, it would also give Alcoa notice as to the control requirements it must meet before it decides whether to restart either plant which would ensure expeditious limitations emissions should either plant restart.

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[68] 86 Fed. Reg. 16055 at 16057 (Mar. 26. 2021).
[69] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 170.
[70] *See*, e.g., Gallagher, Dave, Two front-runners in reopening the Intalco facility offer jobs, cleaner operation, Bellingham Herald, October 20, 2021, available at https://www.bellinghamherald.com/news/business/article255135332.html.
[71] 77 Fed. Reg. 76174 at 76191 (Dec. 26, 2012).

## C. Ash Grove Cement Plant

The Ash Grove Cement plant is a dry process cement kiln in the Duwamish Industrial area of Seattle. The cement plant has a Q/d value based on 2014 emissions of 23.1. The plant is located only 53.8 kilometers from Alpine Lakes Wilderness Area[72] and, according to NPCA, impacts 9 Class I areas in total.[73] According to Ecology, the primary regional haze pollution from the plant come from the cement kiln and the associated clinker cooler baghouses.[74] The plant is capable of burning coal, natural gas, and tire-derived fuels.[75] The plant is equipped with a Dustex 10-module pulse jet baghouse which it installed in 2019.[76]

Ecology identifies a 5.1 pound NOx per ton of clinker on a 30-day rolling average as an emission limit for the Ash Grove cement plant that is part of its long term strategy.[77] However, Ecology has not included any evidence in its draft SIP that the 5.1 lb NOx/ton clinker emission limit is an enforceable requirement of any permit or rule, or that there is an enforceable requirement to install SNCR which Ecology also states must be installed (or perhaps is currently installed). Ecology did include in the draft SIP a 2013 Consent Decree between EPA, Ash Grove Cement Company, and other parties including Ecology and Puget Sound Clean Air Agency (PSCAA) in Appendix E of its draft regional haze SIP. That Consent Decree did not set any specific NOx emission limit or NOx control requirement for the Seattle Ash Grove cement plant, although it did set specific limits for other Ash Grove cement plants located in other states. For example, for the Ash Grove cement plants in Foreman, Arkansas and in Chanute, Kansas, the 2013 Consent Decree required installation of SNCR and imposed a NOx limit of 1.5 lb/ton of clinker, applicable on a 30-day rolling average, to be met by 12/31/2015.[78] For the Ash Grove cement plant in Seattle, the 2013 Consent Decree required Ash Grove to submit an optimization protocol in accordance with Appendix A of the Consent Decree "for the purpose of optimizing the operation of the Seattle Kiln to reduce NOx emissions to the maximum extent practicable from that Kiln."[79] The Consent Decree requires that the "Seattle Kiln NOx Emission Reduction Report shall conform to the applicable procedures set forth in Appendix A [of the Consent Decree] for the establishment of a 30-Day Rolling Average Emission Limit for NOx at the Seattle Kiln" and that Ash Grove must demonstrate compliance with that emission limit "consistent with the requirements and deadlines specified in Appendix A" of the Consent Decree.[80] While the Consent Decree outlined the process for establishing and complying with a

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[72] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 162.
[73] Based on NPCA's Regional Haze Fact Sheet for Washington, Sources of Visibility Impairing Pollution in Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[74] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 167.
[75] *Id.*
[76] *Id.* at 169.
[77] *Id.* at 212.
[78] *See* 2013 Consent Decree, *United States et al. v. Ash Grove Cement Company*, (No. 2:13-cv-02299-JTM-DJW) at 22-23 (¶¶13 and 15), in Appendix E of the Public Review Draft, Second Regional Haze Plan, October 2021.
[79] 2013 Consent Decree, *United States et al. v. Ash Grove Cement Company*, (No. 2:13-cv-02299-JTM-DJW) at 25 (¶¶21), in Appendix E of the Public Review Draft, Second Regional Haze Plan, October 2021.
[80] *Id.*

NOx emission limit with EPA and PSCAA,[81] it does not specify a specific emission limit to be complied with. Ecology has not adequately explained or provided any documents that show how the 5.1 lb/ton of clinker NOx limit has been made into an enforceable requirement[82] or that it is being complied with. It does not appear that requirements that Ecology states have been established under the 2013 Consent Decree have been incorporated into the Ash Grove operating permit yet either, as the current operating permit in place for the Ash Grove cement plant does not require the use of SNCR and does not specify a NOx emission limit of 5.1 lb/ton of clinker.[83]

While it is assumed that the 5.1 lb/ton of clinker limit is enforceable by the PSCAA and Ecology through the mechanism established under 2013 Consent Decree, for the purpose of taking credit for the NOx emission limit as part of its Long Term Strategy and Regional Haze SIP, Ecology is required to provide evidence that it has adopted any requirement of its Long Term Strategy in final form.[84] Such evidence would include the submittal of the actual regulation or document to be incorporated into the SIP as an enforceable requirement.[85] However, the Draft SIP does not cite to any documents which include the 5.1 lb/ton of clinker NOx limit at the Ash Grove Cement Plant. Any measure included in the Long Term Strategy is required to have enforceable emission limitations pursuant to 40 C.F.R. 51.308(f)(2), and Ecology thus needs to provide evidence that the 5.1 lb/ton of clinker NOx limit is an enforceable emission limit.

In its discussion of the facility-specific four factor analyses for the Ash Grove Cement Plant, Ecology states that the 2013 Consent Decree required the Seattle Ash Grove Cement Plant to optimize an SNCR system.[86] However, the Consent Decree does not specifically refer to an SNCR system at the Seattle Ash Grove plant, and the current operating permit for the Seattle Ash Grove plant does not even mention an SNCR system. Ecology acknowledges that Ash Grove submitted a permit application in 2016 for installation of an SNCR system, but a permit has not been issued yet "because of unresolved technical issues."[87] Ecology describes the main technical issue as that the "permit application requested to be operated the SNCR process on an 'as needed' basis" to achieve the 5.1 lb/ton of clinker NOx limit.[88] The facility, which has a capacity of 750,000 tons of clinker per year,[89] is currently subject to a NOx limit of 1,846 tons

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[81] *Id.* at ¶22.
[82] Appendix M of the WDOE Draft Regional Haze Plan does include an August 26, 2016 letter from EPA to Ash Grove Cement Company that approves the limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average, but it is not clear that the EPA letter is an enforceable document. Further, the EPA letter does not mention an SNCR system.
[83] Air Operating Permit No. 11339 issued to Ash Grove Cement Company, last amended June 13, 2018, available at https://pscleanair.gov/DocumentCenter/View/214/Air-Operating-Permit-PDF?bidId=.
[84] This is required by EPA's SIP submittal completeness guidelines in 40 C.F.R. Part 51, Appendix V, Sections 2.1.b and d.
[85] 40 C.F.R. Part 51, Appendix V, Section 2.1.d.
[86] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 169.
[87] *Id.* at 169.
[88] *Id.*
[89] PSCAA Statement of Basis for Ash Grove Cement Company, Air Operating Permit Administrative Amendment 4 issued 6/13/18, at 1, 47, available at https://pscleanair.gov/DocumentCenter/View/216/Statement-of-Basis-PDF?bidId=.

per 12-month period,[90] which equates to an annual limit of 4.92 lb/ton of clinker when the plant is operating at maximum capacity. Unless the Ash Grove plant is not currently complying with the 5.1 lb/ton of clinker NOx limit, it is not clear that SNCR would be required to meet the 5.1 lb/ton clinker NOx limit. Ecology must disclose the current compliance status of the Ash Grove plant with the 5.1 lb/ton limit on NOx which Ecology is claiming is part of its Long Term Strategy.

Further, Ecology has failed to provide an adequate four-factor analysis of controls for the Ash Grove Cement Plant. It appears that Ecology may be finding that SNCR is a cost effective control for the Ash Grove plant that it will require as part of its regional haze plan, but it is unclear. Ecology states "PSCAA and Ash Grove are working on resolving the technical issues in the [SNCR] application with the goal of issuing a permit for the SNCR system. This permit will form the basis for emission standards that will apply to the SNCR system. Ecology intends to supplement the RHR SIP once the permit is issued."[91] Ecology has selected the Ash Grove Cement Plant as a facility to be included in its Long Term Strategy in its regional haze plan for the second implementation period. Thus, Ecology is required to perform a four-factor analysis of controls for the facility and to establish the enforceable requirements for the facility in the context of this current regional haze SIP revision. Considering that Ash Grove has requested to operate the SNCR on an "as needed" basis to achieve the NOx limit of 5.1 lb/ton of clinker, it is clear that the 5.1 lb/ton of clinker NOx limit is not reflective of the NOx removal capabilities of SNCR at the Ash Grove Cement Kiln. As stated above, the 2013 Consent Decree required at least two cement kilns to meet a much lower 1.5 lb/ton of clinker NOx limit with SNCR and .

Rather than determine the appropriate limit with SNCR at the Ash Grove cement kiln or address other methods of reducing NOx at the plant, Ecology states that it "has determined the EPA Consent Decree limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average is adequate for reasonable progress at this time until a final permit for the SNCR system is issued by Puget Sound Clean Air Agency."[92] Ecology's approach does not meet the regional haze requirement that the emission reduction measures necessary to make reasonable progress be included in the long term strategy pursuant to 40 C.F.R. 51.308(f)(2)(i). Ecology must conduct a four-factor analysis now as part of its regional haze plan for the Ash Grove cement plant to fully evaluate all cost-effective controls and to impose an emission limit reflective of the efficacy of the control required.

Ecology briefly evaluated the top NOx control technology, SCR, for the Ash Grove plant, but discounted the control due to SCR operational problems that could occur if it was installed upstream of the baghouse (because the high particulate could foul the catalyst) or if it was installed downstream of the baghouse (because the exhaust temperature would be too low for effective operation of the SCR and require installation of a heat exchanger).[93] However, another top control that Ecology failed to evaluate is the control option of installing catalytic ceramic

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[90] Air Operating Permit No. 11339, issued to Ash Grove Cement Company by PSCAA, last amended June 13, 2018, at 10, available at https://pscleanair.gov/DocumentCenter/View/214/Air-Operating-Permit-PDF?bidId=.
[91] *Id.*
[92] *Id.*
[93] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 168.

filters in the existing main baghouse at the cement kiln. Several vendors are offering catalytic ceramic filter systems for baghouses that can remove NOx through embedded catalysts in the filter, particulate matter, and SO2 with the use of dry sorbent injection, such as Tri-Mer UltraCat and Haldor Topsoe CataFlex™ catalytic filter bags that can be installed in place of or inside a standard filter bag at an existing baghouse. Such vendors claim that catalytic filters can achieve 90% or greater NOx removal.[94] Notably, the catalytic ceramic filters have been geared towards cement kilns, among other facilities, to help meet the Portland cement maximum achievable control technology (MACT) standards.[95]

Recently, a cost assessment for the use of a ceramic catalytic filtration system was done for the GCC Pueblo Cement Plant in Colorado.[96] That information can be used to estimate the costs of using a catalytic ceramic filtration system at the Ash Grove plant. The GCC plant is somewhat similar to the Ash Grove Seattle plant in that both cement kilns use the dry kiln process and use a preheater and precalciner.[97] The GCC Pueblo Plant has a higher cement production rate at 3,750 tons/day compared to 2,200 tons per day at the Seattle Ash Grove cement plant.[98] Thus, the cost estimate of the use of a ceramic catalytic filtration system would be higher than the costs of such a system at the Ash Grove plant in Seattle.

There are a few options for using a ceramic catalytic filtration system at the Ash Grove Plant: 1) install a stand-alone catalytic ceramic filtration system that would be used after the existing baghouse, 2) replace an existing baghouse with a stand-alone catalytic ceramic filter system, and 3) install catalytic filter bags within the existing baghouse. Given that a new baghouse was recently installed at the Ash Grove plant, the third option would be the most cost effective option.

Tri-Mer provided a cost estimate to replace the existing bags of the baghouse at the GCC Pueblo cement plant with catalytic ceramic filter elements. As discussed in the attached report on GCC Pueblo, Tri-Mer's costs take into account the addition of an ammonia injection system and that the exhaust flue gas of the cement kiln would no longer need to be cooled to a temperature required by the existing fabric filter bags.[99] Tri-Mer determined that the cost for a bag-to-ceramic filter retrofit would cost $800/ton of NOx removed at the GCC Pueblo Plant and would reduce NOx by 90%, as well as continuing to remove PM10 and PM2.5 at very high efficiencies (greater than 99.9%).[100] Tri-Mer's cost effectiveness value reflects a capital cost of $8,999,200

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[94] *See*, e.g., https://tri-mer.com/hot-gas-treatment/hot-gas-filtration.html. *See also* Exhibit 3, Haldor Topsoe CataFlex™ brochure; and GEA BisCat – Ceramic catalyst filter information available at https://www.gea.com/en/news/trade-press/2019/biscat-ceramic-catalyst-filter.jsp.

[95] *See* Air & Waste Management Association, The Magazine for Environmental Managers, Sponsored Content, "Catalytic Filter Technology Provides Important Flexibility for Controlling PM, NOx, SOx, O-HAPS," October 2018, attached as Ex. 4 and available at https://pubs.awma.org/flip/EM-Oct-2018/sponsoredcontent_trimer.pdf.

[96] Klafka, Steve, Wingra Engineering, GCC Rio Grande – Pueblo Cement Plant, Four-Factor Reasonable Progress Analysis, September 23, 2021, hereinafter GCC Pueblo Four Factor Analysis, attached as Ex. 5.

[97] *See* GCC Pueblo Four Factor Analysis, Appendix B at 2 (Ex. 5); *see also* PSCAA Statement of Basis for Ash Grove Cement Company, Air Operating Permit Administrative Amendment 4 issued 6/13/18 at 3 (Ex. 6).

[98] *See* GCC Pueblo Four Factor Analysis, Appendix B at 2; *see also* PSCAA Statement of Basis for Ash Grove Cement Company Air Operating Permit at 1.

[99] GCC Pueblo Four Factor Analysis at 12.

[100] *Id.,* Appendix F at 5-6.

for bag replacement with catalytic ceramic filters and an annual operating expense cost for the control system of $1,620,000/year.[101] The annual operating costs take into account power costs, use of aqueous ammonia (19% by weight), maintenance, and replacement of the filters every 10 years.[102] The use of aqueous ammonia is safer than using anhydrous ammonia, and there is not a federal requirement for an accidental release plan.

Tri-Mer states that some of the added benefits of using a ceramic catalytic filtration system for control of NOx, as well as particulate, include that there is minimal catalyst plugging, reduced ammonia slip (well below 10 parts per million), and negligible catalyst deactivation.[103] Tri-Mer states that "a ceramic filter has no deactivation of the catalyst in a continuous operation for 10 years+."[104] In addition, with the use of sorbent injection, the catalytic ceramic filtration system could also be used to reduce SO2 emissions by 90% or more.[105]

The Seattle Ash Grove Cement facility had NOx emissions of 1,144 tons per year in 2014,[106] thus a 90% reduction would equate to 1,030 tons per year of NOx reduced from 2014 levels. Based on the allowable NOx emission rate of 1,846 tons per 12-month period and the annual capacity of the Ash Grove plant of 750,000 tons of clinker production, the use of catalytic ceramic baghouse filters would allow for a NOx emission limit of approximately 0.5 lb/ton of clinker.[107] This is significantly lower than the 5.1 lb/ton clinker NOx limit that Ecology is proposing to be part of the state's Long Term Strategy. Thus, Ecology must fully evaluate the use of catalytic ceramic filter bags at the Ash Grove cement plant as a top regional haze control.

SNCR should be considered a second tier control compared to catalytic ceramic baghouse filters. However, SNCR can most assuredly reduce NOx to lower emission rates than the 5.1 lb/ton of clinker emission rate that Ash Grove is apparently negotiating with PSCAA for its SNCR system.[108] There are several cement kilns with SNCR with lower NOx limits than 5.1 lb/ton of clinker. Indeed, the 2013 Consent Decree requires a NOx limit of 1.5 lb/ton of clinker, applicable on a 30-day rolling average, to be met by 12/31/2015 at several cement kilns.[109] In any evaluation of SNCR as a regional haze control for the Seattle Ash Grove plant, Ecology must evaluate the maximum emission reduction capabilities of the control and not simply allow

[101] *Id.*, Appendix F at 6. Note that the annual operating expense was calculated by subtracting the estimated Capital Investment of $8,999,200 from estimated lifetime cost (Capital expense plus 20 years of operating expenses) of $41,399,200 provided for the GCC Pueblo plant by Tri-Mer.
[102] *Id.*, Appendix F at 6.
[103] *Id.,* Appendix F at 7.
[104] *Id.*
[105] *Id.,* Appendix F at 5.
[106] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 84.
[107] *See* PSCAA Statement of Basis for Ash Grove Cement Company, Air Operating Permit Administrative Amendment 4 issued 6/13/18, at 1 (Ex. 6); and Air Operating Permit No. 11339, issued to Ash Grove Cement Company by PSCAA, last amended June 13, 2018, at 10 (Ex. 7). Assuming 90% NOx control from the 1,846 tons NOx per 12-month period limit equates to 0.5 lb/ton of clinker at maximum production capacity of 750,000 tons of clinker per year.
[108] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 168.
[109] *See* 2013 Consent Decree, *United States et al. v. Ash Grove Cement Company*, (No. 2:13-cv-02299-JTM-DJW) at 22-23 (¶¶13, 15, 25, 30), in Appendix E of the Public Review Draft, Second Regional Haze Plan, October 2021.

periodic implementation of an SNCR system at the Ash Grove cement plant to meet an unreasonably high NOx emission limit.

With respect to SO2 emissions from the Ash Grove Plant, Ecology states the following about the cement plant:

> SO2 emissions at the plant come from burning sulfur containing fuels. The plant is capable of burning coal, natural gas, and tire-derived fuels. The plant has not been using coal for the last couple of years, but still has the ability to use it. As the facility can still use coal, SO2 emissions from the 2014 EI (with coal combustion) were included in the modeling to determine progress. The alkaline cement clinker removes some SO2 from the combustion gases. The facility uses this as a primary method of SO2 control.

WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 167.

If the plant has not been using coal in the past couple of years then, assuming that fuel change has reduced SO2 emissions, an emission control requirement of at least no longer burning coal at the Seattle Ash Grove plant should be imposed as a minimum regional haze control for SO2 emissions from the cement plant. However, the use of catalytic ceramic filter with sorbent injection should also be evaluated as an available SO2 control for the cement plant.

In summary, if Ecology is going to include the Ash Grove cement plant as part of its Long Term Strategy, the state's plan must evaluate controls for the facility in a four-factor analysis and impose appropriate emission limits and control requirements. Ecology admits that the 5.1 lb/ton of clinker emission rate is not reflective of even full-time operation of an SNCR system, and yet it is proposing a 5.1 lb/ton NOx limit that purportedly requires SNCR for the facility in its Long Term Strategy with a plan to revise the regional haze plan once a permit for the SNCR system is issued by PSCAA. Ecology has not even provided evidence that the 5.1 lb/ton clinker NOx limit has been adopted in a final enforceable form such that it can be incorporated into the federally enforceable SIP. Ecology's approach does not meet the regional haze requirement that the emission reduction measures necessary to make reasonable progress be included in the long term strategy pursuant to 40 C.F.R. 51.308(f)(2)(i). Ecology must conduct a four-factor analysis now as part of its regional haze plan for the Ash Grove cement plant to fully evaluate all cost-effective controls and to impose an emission limit reflective of the efficacy of the control required.

### D. Cardinal FG Winlock Glass Plant

The Cardinal FG Winlock plant is a flat glass manufacturing plant in Winlock, WA. According to Ecology, its 2014 NOx emissions were 791 tons per year based on 2014 emissions.[110] Thus, the facility is a large source of NOx. Ecology calculated a Q/d value for this facility of 10.7,

[110] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 84.

which exceeded its threshold of 10 that it used to select sources for four-factor analyses of controls.[111] Therefore, the Cardinal Glass Plant is subject to the four-factor analysis.

Ecology did not request a four-factor analysis of pollution controls for the Cardinal Glass Plant. Instead, Ecology proposes to rely on the fact that the company recently submitted a permit application to install SCR controls, which it proposed concurrently with an increase in glass production capacity from 650 tons per day to 750 tons per day.[112] According to Ecology, the company is also requesting a much lower facility-wide NOx limit of 249.62 tons per year, which apparently is 583.05 tons per year lower than the facility's current emission limits.[113] According to Ecology, to ensure kiln exhaust gas temperatures are high enough for the successful operation of the SCR, the existing spray dryer and electrostatic precipitator (ESP) will have to operate at higher temperatures which will increase emissions of SO2, PM10, and PM2.5.[114] It also appears that the company is requesting lower NOx limits, as well as lower carbon monoxide limits, to allow the Cardinal Glass Plant to be considered a minor source (i.e., under 250 tons per year), so that the emission increases of SO2 and PM2.5 due not trigger prevention of significant permitting requirements as a major modification.

Ecology is relying on the Cardinal's plans to install SCR as part of its Long Term Strategy. Ecology has included a copy of SWCAA's Air Discharge Permit 20-3409, issued February 11, 2021, in Appendix H of its SIP and presumably will be including that permit as the enforceable requirement to incorporate into its regional haze SIP.

However, the issuance of the permit for the SCR and increase in capacity does not negate the need for Ecology to conduct its own four-factor analysis of controls and, particularly in this case, to establish appropriate emission limits as is required to be included in the Long Term Strategy pursuant to 40 C.F.R. 51.308(f)(2).

With respect to NOx, the facility-wide NOx emissions in 2014 were 791 tons per year, and the facility-wide potential to emit is 249.62 tons per year,[115] which only reflects a NOx reduction with SCR of 68%. That is much lower than the 90%+ control efficiency that SCR is capable of achieving. In addition, the prior permit for the Cardinal FG Winlock Glass Plant required use of the 3R Process for control of NOx emissions,[116] and it appears that process is no longer required in the 2021 permit. The Pilkington 3R Process is described as using "various hydrocarbon fuels, injected into the furnace waste gas stream, as the agent to reduce NOx to harmless nitrogen and water vapor."[117] If the company were required to add SCR along with using the existing 3R Process, it could achieve lower NOx emission rates. Ecology must explain why it is justifiable

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[111] *Id.* at 160 and 162.
[112] *Id.* at 171.
[113] *Id.* at 172.
[114] *Id.*
[115] *Id.*
[116] SWCAA Air Discharge Permit 04-2568R2, 12/16/2008, at 4, available at https://www.swcleanair.gov/docs/permits/TitleV/SW08-14-R1AOP.pdf and attached as Ex. 8.
[117] State of New Jersey, Department of Environmental Protection, State of the Art (SOTA) Manual for the Glass Industry, July 1997, at 3.15-22, available at https://p2infohouse.org/ref/14/13344.pdf.

for Cardinal FG Winlock to stop using the 3R Process to control NOx, when it could readily use additional NOx controls in addition to the 3R Process.

In addition, the use of low temperature catalysts should have been evaluated for the SCR, to avoid having to reheat the gas stream which will reduce the effectiveness of the PM and SO2 controls. Such low temperature catalysts would reduce if not eliminate the projected increases in SO2 and particulate matter with the SCR, which are claimed to be due to the need to achieve a higher temperature in the flue gas due to the SCR.

Another option Ecology should consider for the Cardinal Glass Plant is the use of ceramic catalyst filters along with the existing 3R process, which can reduce NOx at lower temperatures than conventional SCR and also capture particulate and SO2. This control method is discussed above in Section II.C above on the Ash Grove Cement Plant and it is also discussed in the January 27, 2021 Four-Factor Reasonable Progress Analysis for the Ardagh Glass plant in Seattle, Washington, done by Wingra Engineering, S.C. and attached as Exhibit 10.

Ecology states that RCS 70A.15.2220 "requires that when a source decides to modify or replace an existing emission control system, Ecology or the local air pollution control authority must assure that the modified ore replacement control system meets a reasonably available control technology (RACT) level of emissions control at a minimum."[118] RACT is defined under Washington State law as:

> *[T]he lowest emission limit* that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls. RACT requirements for a source or source category shall be adopted only after notice and opportunity for comment are afforded.

RWA 70A.15.1030(20) (emphasis added).

While SCR is a control technology capable of meeting the lowest emission limit, the proposed NOx emission limit does not appear to require the "lowest emission limit" that can be met with SCR. Further, with the decreases in SO2 and PM removal efficacy that will occur as a result of the SCR installation, it is questionable whether the SO2 and PM emission limits reflect RACT because the revised SO2 and PM emission limits do not reflect the lowest emission limit for the spray dryer and electrostatic precipitator that are installed at the glass furnace. Ecology must comply with the state law RCW 70A.15.2220 cited in its draft Long-Term Strategy as part of its review and determination of appropriate regional haze emission limitations for the Cardinal FG Winlock glass plant in its Regional Haze plan for the second implementation period. It has an obligation to ensure RACT level controls are met.

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[118] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 215.

The regional haze four-factor analysis applies to the Cardinal Glass Plant *in conjunction with* any other Clean Air Act requirements. The fact that the Cardinal Glass Plant has received a permit requiring the installation of SCR does not obviate the need for the state to comply with reasonable progress requirements  The emission limits of the permit, as described in the draft regional haze SIP, do not reflect the maximum capabilities of SCR, including the ability to use low temperature catalyst to avoid or eliminate the SO2 and particulate matter increases that were projected to occur with SCR. Ecology must conduct its own four-factor analysis of regional haze controls and impose emission limits that reflect the controls it determines are necessary to make reasonable progress towards the national visibility goal.

## III. Review and Comments on Other Sources Selected by Ecology for Review That Were Unjustifiably Deferred from Ecology's Proposed Long Term Strategy

As previously stated, Ecology used a Q/d analysis and selected a Q/d value of 10 or higher as a threshold for selecting sources to require a four-factor analysis of regional haze controls.[119] Ecology required four-factor analyses for five petroleum refineries and seven pulp and paper mills.[120] Ecology then selected the refineries as the first priority of sources to focus on for regional haze controls. Ecology prioritized pulp and paper mills lower than refineries because they "are not located as close to each other as the refineries so they do not have as great of a cumulative effect."[121] Ecology also states that the potential reduction in regional haze emissions from pulp and paper mills is "vastly less than the potential refinery emission reductions."[122]

Ecology states that it must follow its RACT rule requirements before it can legally establish control requirements.[123] However, Ecology has not conducted a RACT evaluation in this regional haze plan. Yet, the regional haze plan for the second implementation period is required to evaluate controls for selected sources and determine through a four-factor analysis what control measures are necessary to make reasonable progress towards the national visibility goal.[124] For a source that is found subject to the required reasonable progress four-factor analysis as a result of a state's reasonable progress screening process, the state must ensure the analysis is conducted as part of its regional haze plan. Neither the Act nor EPA's rules provide an "off-ramp" for a source in this situation. Ecology's Public Review Draft is stated to be its State Implementation Plan (SIP) revision for the second regional haze plan implementation period of

[119] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 160.
[120] These company four-factor analyses are provided at https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/RegionalHaze.htm.
[121] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 166.
[122] *Id.* at 167.
[123] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 163.
[124] *See* U.S. EPA, Guidance on Regional Haze Plans for the Second Implementation Period, August 20, 2019, at 28 (Step 4).

2018 to 2028, and thus it is assumed for the purpose of these comments that the Public Review Draft is the plan to be submitted to EPA for approval.

Comments are provided herein on the four-factor analyses and Ecology's analysis of controls for the five refineries and the seven pulp and paper mills.

## A. Four-Factor Analyses for the Oil Refineries

Ecology states in its draft regional haze plan that the refineries in Washington "are over 40 years old and the facilities have maintained the majority of the equipment in a manner that has not required updating emission controls to current standards."[125] Ecology did a nationwide comparison of 2014 facility-wide NOx emissions per barrel of production capacity for the five Washington refineries to 83 other refineries located in the U.S. and found that "Washington refineries represent four of the top five facilities in the nine states in terms of NOx emissions per 1,000 barrels produced per day."[126]

Ecology requested four-factor analyses from the five Washington refineries to address each fluid catalytic cracking unit (FCCU), each boiler with heat input greater than 40 MMBtu/hr, and each heater with heat input greater than 40 MMBtu/hr that has not been retrofitted with NOx controls since 2005.[127] None of the five refineries for which Ecology requested four-factor analyses found that low NOx burners or ultra low NOx burners (LNB/ULNB) or SCR were appropriate for regional haze reasonable progress controls. Either the companies claimed that a control, such as ULNB, was not technically feasible for a heater or boiler, or a company claimed that controls were not cost effective. Ecology conducted its own cost effectiveness analyses for the application of SCR to the refinery heaters and boilers. Ecology states that two refineries did not submit analyses for their FCCUs, and Ecology subsequently decided to evaluate SCR for those FCCUs "since they are a large source of NOx emissions."[128]

### 1. Comments on Ecology's Determination of Cost Effective Controls for the Petroleum Refineries

Ecology conducted SCR cost effectiveness analyses for several emissions units at the refineries using EPA's SCR cost calculation spreadsheet made available with its Control Cost Manual.[129] Ecology states in its discussion of the four-factor analyses of controls for the units at each refinery that it found SCR would be cost effective for the FCC units and for various heaters and boilers.[130] Ecology's draft SIP identifies a $6,300/ton reasonableness threshold for NOx controls

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[125] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 184.
[126] *Id.* at 185-186 (Table 7-6).
[127] *See*, e.g., BP Cherry Point Refinery Regional Haze Four Factor Analysis, April 2020 (hereinafter "BP Cherry Point Analysis") at 2, available at https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/RegionalHaze.htm.
[128] *Id.* at 187.
[129] *Id.* at 187.
[130] *Id.*

in its discussion of controls for the pulp and paper industry.[131] It appears, but is not entirely clear, that Ecology is using a similar reasonableness threshold for NOx controls at the refineries. For any cost threshold selected by a state, EPA's regional haze guidance requires that the State Implementation Plan (SIP) "explain why the selected threshold is appropriate for that purpose and consistent with the requirements to make reasonable progress."[132] It must be noted that other states have adopted higher cost effectiveness reasonableness thresholds. For example, Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton.[133] Colorado is also using a reasonableness cost threshold of $10,000/ton.[134] New Mexico is using a reasonableness cost effectiveness threshold of $7,000/ton.[135]

With respect to determining whether a NOx control is cost effective for a particular heater or boiler at a refinery, it is important to consider the costs that similar sources have had to bear to meet Clean Air Act requirements for NOx. For example, several Californian Air Districts as well as the states of Texas, Massachusetts, New York, and Georgia have set NOx emission limits for existing heaters and boilers that are reflective of the use of LNB/ULNB, SNCR, or SCR.[136] While these emission limits were often set to address ozone and/or PM2.5 nonattainment issues, the fact is that each of these controls can be quite cost effective. For example, a San Joaquin Valley Air Pollution Control District (SJVAPCD) cost analysis for ULNBs shows that the retrofitting of such controls to meet a NOx limit of 6 ppm would have cost effectiveness values ranging from $545/ton to $3,270/ton, with the higher cost effectiveness values being at smaller units (the smallest size unit evaluated was 30 MMBtu/hr) and/or lower capacity factors.[137] In addition, based on a SJVAPCD cost analysis for SCR to meet NOx emission rates of 2.5 ppm, SCR was found to have a cost effectiveness of $1,025/ton to $6,149/ton for heaters and boilers as small as 30 MMBtu/hr, with the lowest cost effectiveness values for the larger units and units that operate at higher capacity factors.[138]

We encourage Ecology to review Table 42 of the attached March 6, 2020 report of four-factor analyses for the oil and gas industry,[139] which includes a list of state and local air agency emission limits and rules applicable to existing natural gas-fired heaters and boilers. As that report indicates, the most stringent NOx limit for units greater than or equal to 75 MMBtu/hour required of existing sources in the listed state and local rules is 5 ppm, which most likely reflects

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[131] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 182.
[132] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 39.
[133] *See* Oregon Regional Haze State Implementation Plan for the Period 2018-2028, Aug. 27, 2021 Public Notice Draft, at 35, 45.
[134] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, available at https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v.
[135] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.
[136] Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 139-145, attached as Ex. 10.
[137] *Id.* at 125 (Table 36).
[138] *Id.* at 135 (Table 41).
[139] Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 139-145, attached as Ex. 10.

use of SCR. There are several examples of similar sources having to bear the costs of these controls to meet Clean Air Act requirements. Ecology would thus be justified in finding SCR for the heaters, boilers and FCCUs that it evaluated in its draft regional haze plan as cost effective.

Although Ecology states that SCR would be cost effective for several refinery emission units, Ecology also states it "will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates."[140] Presumably, Ecology states this because the Western States Petroleum Association (WSPA) has apparently contended that Ecology did not use the EPA SCR cost spreadsheet appropriately and that Ecology's application of the EPA's SCR cost spreadsheet is not appropriate for refineries.[141] However, as Ecology stated in its draft regional haze plan, the Washington refineries generally did not adequately document the basis for their SCR cost assessments. Ecology chose to use EPA's SCR cost spreadsheet which is based on the SCR chapter of the Control Cost Manual and which, in turn, has been very well documented and which also went through public notice and comment.

The EPA's SCR cost calculation spreadsheet was based on cost algorithms for utility boilers, but that fact does not make the SCR cost algorithms not applicable to other types of emission units such as those at refineries. Several of the refinery emission units that Ecology evaluated for SCR are boilers and process heaters. The emissions characteristics from those sources are similar or identical to the emission characteristics from boilers. In fact, EPA's AP-42 emission factors for petroleum refining refer to its emission factors for boilers (i.e., Section 1.3 "Fuel Oil Combustion" or Section 1.4 "Natural Gas Combustion") for determining emissions from boilers and process heaters used in the petroleum refining industry.[142]

The SCR cost spreadsheet algorithms were developed based on its Integrated Planning Model (IPM) version 6. The SCR cost documentation for the IPM written by Sargent & Lundy was in turn based on a wealth of design and cost information, including from the "Analysis of the [Midwest Ozone Group (MOG)] and [Lake Michigan Air Directors Consortium (Ladco) FGD and SCR Capacity and Cost Assumptions in the Evaluation of the Proposed EGU 1 and EGU 2 Emission Controls" and the J.E. Cichanowicz study "Current Capital Costs and Cost-effectiveness of Power Plant Emissions Control Technologies," as well as Sargent & Lundy's in-house database of recent SCR projects.[143] The costs generally reflect hot side, high dust SCRs, which also likely reflects the type of SCR that would be employed at refinery emission units including FCCUs.[144] While the cost algorithms are identified as providing the "average" costs with the "average" project,[145] the algorithms are also based on a significant amount of SCR

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[140] *Id.*
[141] *Id.* at 188, 192, and 194.
[142] *See* U.S. EPA, AP-42, Chapter 5.1, Table 5.5-1, available at https://www.epa.gov/sites/default/files/2020-09/documents/5.1_petroleum_refining.pdf. *See also* EPA, AP-42, Chapter 1 External Combustion Sources, Sections 1.3 and 1.4, available at https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.
[143] *See* Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, Final, January 2017, prepared by Sargent & Lundy, at 1, available at https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf.
[144] *Id.*
[145] *Id.*

installation and SCR retrofit data from the industry where such controls are probably the most widely used (i.e., the fossil fuel-fired electric utility industry).

EPA's August 20, 2019 regional haze guidance refers to its cost spreadsheets developed as part of its recommendation that states follow the EPA's Control Cost Manual "to facilitate apples-to-apples comparisons of different controls options for the same source, and comparisons across different sources."[146] EPA does not require vendor-generated cost assessments for making regional haze control decisions.[147] EPA also cautions against relying solely on vendor cost estimates that are not sufficiently documented and without verifying that the vendor followed the costing principles of the EPA's Control Cost Manual.[148] The Washington refineries relied on the EPA SCR cost calculation spreadsheet for SCR cost analyses for at least some refinery emission units, although the refineries did not generally document its decisions to use higher retrofit factors or higher costs for items such as ammonia reagent as is discussed further below.[149] Thus, Ecology should not discount its cost effectiveness analyses of SCR for refinery emission units as not sufficiently accurate to determine that SCR is cost effective for an emission unit at a refinery.

SCR systems have been retrofit to many refinery emission units over the years, including at fluid catalytic cracking units (FCCUs). A paper from 2002 discusses the success of SCR retrofit at an FCCU at the BP Whiting Refinery and refers to SCR installations at FCCUs dating back to 1986.[150] SCR has also been used on refinery boilers and heaters, including at some Washington refineries,[151] and can achieve in excess of 95% NOx control from the NOx emitted from the heaters.[152] Experience using SCRs in the refinery industry shows the controls are reliable and have low operational and maintenance costs.[153]

For all of these reasons, Ecology is justified to use the EPA SCR cost spreadsheet to determine cost effectiveness of SCR at the heaters, boilers and FCCUs for the five refineries it evaluated for controls for its regional haze plan.

In its draft regional haze plan, Ecology identified the emission units listed in Table 4 for which SCR would be a cost effective regional haze control. The cost effective controls identified by

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[146] *See* U.S. EPA, Guidance on Regional Haze Plans for the Second Implementation Period, August 20, 2019, at 31.
[147] *Id.* at 32.
[148] *Id.*
[149] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P at P-173 to P-194 (Shell Four-Factor Analysis), P-229 to P-283 (Tesoro Four-Factor Analysis), and P-334 to P-336 (U.S. Oil Four-Factor Analysis).
[150] *See* Bouziden, Gerald, K. Gentile and R.G. Kunz, Selective Catalytic Reduction of NOx from Fluid Catalytic Cracking Case Study: BP Whiting Refinery, National Environmental & Safety Conference, April 23-24, 2002, New Orleans, LA, at 1, available at https://www.cormetech.com/wp-content/uploads/2018/05/env-03-128-kunz-0-Whiting-Refinery-FCC.pdf.
[151] For example, BP Cherry Point has installed SCR on its #2 hydrogen plant SMR furnace, its #6 and #7 boilers, according to its August 26, 2014 Air Operating Permit #015R1M1 on the Northwest Clean Air Agency's (NWCAA's) website at https://nwcleanairwa.gov/?wpdmdl=981.
[152] *See*, e.g., Jensen-Holm, Hans et al., Haldor-Topsoe, Combating NOx from refinery sources using SCR, available at http://www.topsoe.com/sites/default/files/combating_nox_from_refinery_sources_using_scr.ashx_.pdf; LaPlante, Marie P. et al., How Low Can You Go? Catalytic NOx Reduction in Refineries, available at http://nawabi.de/project/hrsg/Topsoe.pdf.
[153] *Id.*

Ecology and listed in Table 4 below would reduce NOx emissions from the refineries by a total of 3,803 tons per year (based on Ecology's assumed NOx emissions reduced with SCR), reflecting a 64.5% reduction in the total 2014 annual NOx emissions from the five refineries

**Table 4. Ecology's Identification of Cost Effective SCR Determinations at the Petroleum Refineries**[154]

| **Plant** | **Emission Unit** | **Cost Effectiveness, $/ton** | **NOx Reduced, tons per year** |
|---|---|---|---|
| BP Cherry Point | #1 Reformer Heaters | $3,101/ton | 304 tpy |
| | Crude Heater | $2,051/ton | 393 tpy |
| | Reforming furnace #1 (N H2 Plant) | $6,161/ton | 262 tpy |
| | Reforming furnace #2 (S H2 Plant) | | |
| Phillips 66 Ferndale | Crude Heater 1F-1 | $2,640/ton | 166 tpy |
| | FCCU/CO Boiler/Wet Gas Scrubber 4F-101 | $3,954/ton | 247 tpy |
| Shell Puget Sound | Boiler #1 Erie City – 31G-F1 | $2,441/ton | 179 tpy |
| | FCCU Regenerator Unit | $1,948/ton | 521 tpy |
| | CRU #2 HTR, INTERHTR—10H-101, 102, 103 | $6,346/ton | 69 tpy |
| Marathon Petroleum Company (Tesoro) Anacortes Refinery | FCCU | $1,159/ton | 843.3 tpy |
| | F 102 Crude Heater | $2,962/ton | 147.6 tpy |
| | F 201 Vacuum Flasher Heater | $7,589/ton | 57.6 tpy |
| | F 6650 CAT Reformer Heater | $3,736/ton | 117 tpy |
| | F 6651 CAT Reformer Heater | $3,520/ton | 124.2 tpy |
| | F 751 Main Boiler | $2,159/ton | 202.5 tpy |
| | F 752 Main Boiler | $2,570/ton | 170.1 tpy |

Ecology evaluated SCR to achieve 90% NOx removal and assumed a 3.25% interest rate and a 25-year life in amortizing capital costs of control. Ecology's assumptions are defensible. EPA's Control Cost Manual states that, while in theory, SCR can achieve close to 100% NOx removal,

[154] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, at 188 (finding SCR at BP Cherry Point units was cost effective), at 192 (finding SCR at Phillips 66 units was cost effective), at 194 (finding SCR at Shell units was cost effective), and at 198 (fining SCR at Marathon Petroleum Company (Tesoro) units was cost effective). Appendix J at J-1.

in practice, SCRs are routinely designed to achieve 90% or greater NOx removal.[155] Ecology's use of a 3.25% interest rate is justified, as the Federal Reserve Prime Rate has been at 3.25% since March 2020.[156] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[157] A 25-year life of an SCR system is also justifiable as discussed in EPA's Control Cost Manual,[158] as long as the remaining useful life of the emission unit in question is not restricted to a shorter time period. None of the refineries indicated a restricted remaining useful life of any of the above units in the company four-factor analyses.

For those refinery units for which SCR was not determined to be cost effective, Ecology should evaluate SNCR as a NOx control. The McIlvaine Company indicates that urea-based SNCR used at refinery process units and boilers has generally achieved 50-70% NOx reduction.[159]

In addition, Ecology should not limit evaluation of LNB/ULNBs for units greater than 40 MMBtu/hour capacity, as such burners are available for smaller units.[160] The California Air Resources Board (CARB) determined as far back as 1991 that heaters and boilers as small as 5 MMBtu/hour or greater could meet NOx "best available retrofit control technology" (BARCT) limits of 30 ppmv (or about 0.036 lb/MMBtu).[161] However, more recently, California's South Coast Air Quality Management District (AQMD) concluded that even lower NOx limits, as low as 9 ppm, could be met with ULNB at boilers and process heaters as small as 2 MMBtu/hr.[162] This was based on actual ULNB retrofit experience at boilers and heaters in the San Joaquin Unified Air Pollution Control District (SJVAPCD).[163] The Ventura County Air Pollution Control District in California also found that boilers and process heaters as small as 2 MMBtu/hr could meet NOx limits of 9 ppm with ULNB.[164] Thus, Ecology should not limit the evaluation of reasonable progress controls to only heaters and boilers greater than 40 MMBtu/hr.

For companies demonstrating that the retrofit of ULNBs is not technically feasible and for which SNCR or SCR are truly not cost effective, Ecology should evaluate the costs of replacing an existing boiler or heater with a new unit equipped with state-of-the-art ULNBs. If a unit is near the end of its useful life, this could be a very cost effective and readily implementable approach to reducing NOx emissions.

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155 *See* U.S. EPA, Control Cost Manual, Section 4, Chapter 2, at pdf page 5, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
156 https://fred.stlouisfed.org/series/DPRIME.
157 U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
158 *See* U.S. EPA, Control Cost Manual, Section 4, Chapter 2, at pdf page 80, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
159 *See* http://www.mcilvainecompany.com/industryforecast/refineries/background1/text/Chapter%20X/Chapter%20X.htm.
160 *See*, e.g., BP Cherry Point Refinery Regional Haze Four Factor Analysis, April 2020, in Appendix P of Public Review Draft Regional Haze Plan, October 2021, at P-3.
161 As discussed in Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020 at 120 (attached as Ex. 10).
162 *Id.* at 121.
163 *Id.*
164 *Id.* at 121-122.

For those units listed in Table 4 above that Ecology found SCR to be a cost effective control, Ecology should adopt requirements for the companies to install SCR as part of its current regional haze action. Ecology has shown that SCR is cost effective for those units, and Ecology's review of the other three factors do not provide a reason to exclude any of the emission units in Table 4 above from requirement to install SCR requirement to achieve reasonable progress towards the national visibility goal.

Instead of adopting SCR control requirements for the emission units listed in Table 4 above, Ecology states that it will conduct a more extensive cost evaluation of SCR. Yet, the cost algorithms of the EPA SCR cost spreadsheet are already based on numerous SCR cost evaluations. Further, Ecology already requested four-factor analyses of potential regional haze controls from the refineries include for SCR, and Ecology determined that the company analyses were not well documented or justified.[165] In most cases, the cost analyses submitted by the refineries overstate costs and understate emissions reductions, and so the cost effectiveness numbers should not be relied upon by Ecology. In the sections that follow, more specific concerns with each company's four-factor analyses of NOx controls are provided along with a discussion of the four-factor analyses provided by Ecology in its current draft regional haze plan.

### 2. BP Cherry Point Refinery

Ecology calculated a Q/d value for the BP Cherry Point facility of 36.4, and it is ranked 5th highest Q/d on Ecology's list of sources it evaluated.[166] NPCA data shows that the facility impacts regional haze at 14 Class I areas.[167] BP Cherry Point submitted a four-factor analysis for nine emission units at the refinery:

- Crude Charge Heater;
- South Vacuum Heater;
- #1 Reformer Heaters;
- #2 Reformer Heaters;
- Naphtha HDS Charger Heater;
- Naphtha HDS Stripper Reboiler;
- Hydrocracker R-4 Heater;
- #1 Hydrogen Plant (North and South Furnaces);
- #5 Boiler.

[165] *Id.* at 190, 192, 195, 196, 199, and 202 (Ecology stating that the various refinery companies provided limited supporting data for their cost analyses).
[166] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
[167] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.

BP states that Ecology narrowed the request to only LNB/ ULNB and SCR. BP analyzed the cost effectiveness of LNB/ULNB and SCR for these units and found that no controls were cost-effective. The following provides comments on BP's cost effectiveness analyses in its Four-Factor submittal.

*Issues with Four-Factor Analyses for BP Cherry Point*

1. One of the deficiencies in BP Cherry Point's cost analyses is that it used a 5% interest rate in amortizing capital costs.[168] BP claimed that this interest rate was based on the past Federal Reserve Prime Rate, but the Federal Reserve Prime Rate has been at 3.25% since March 2020.[169] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[170] In a cost effectiveness analyses being done today, even a 5.0% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

2. For all of the units except the #5 boiler and the #3 reformer heater, BP used cost estimates that were previously done in 2010 and which reflected a 2007 dollar basis.[171] BP scaled those costs up from 2007 dollars to 2020 dollars using the Nelson Farrar Refinery Construction cost index, which increased capital costs by 41%.[172] EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis.[173] EPA states that "[e]scalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate."[174] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. Notably, for SCR, EPA's SCR cost effectiveness spreadsheet can be used to estimate costs of SCR, as was used by Ecology for the #1 reformer heaters, the crude heater, the reforming furnace #1 (N H2 Plant), and for the reforming furnace #2 (S H2 plant).[175]

3. BP Cherry Point stated that LNBs/ULNBs were not technically feasible on the crude charge heater, the naphtha HDS charge heater, the naphtha HDS stripper reboiler, and the

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[168] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-6.
[169] https://fred.stlouisfed.org/series/DPRIME.
[170] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[171] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses) at P-10 to P-13.
[172] *Id.* at P-13.
[173] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[174] *Id.*
[175] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189-191.

hydrocracker R-4 heater due to flame impingement and that they would need to rebuild the heater to accommodate the burner retrofit.[176] A review of the air operating permit for BP Cherry Point shows that most of these heaters and boilers were installed fifty years ago in 1970. Given the age of the heaters, it could be more economical to replace the heaters and boilers with new heaters equipped with state-of-the-art ultra-low NOx burners. The heaters could also be retrofitted with SCR, which Ecology found to be cost effective.[177]

4. BP Cherry Point Assumed that LNB and ULNB could only achieve NOx emission rates of 0.055 to 0.060 lb/MMBtu for forced and balanced draft heaters with air preheaters.[178] The company provided no citation or support for that statement. NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[179] Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[180]

5. BP applied retrofit factors to the costs of SCR which would increase the capital costs due to purported retrofit difficulty, but BP provided no justification for the use of retrofit factors. For the one unit for which BP utilized EPA's SCR cost spreadsheet, it must be noted that the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology must request justification and documentation for use of any SCR retrofit factors.

6. BP assumed a cost for ammonia reagent in the SCR systems of $0.33/lb, or $660/ton, which is unreasonably high.[181] No basis was cited for this cost. EPA's SCR Control Cost Manual chapter assumes a much lower cost for 29% aqueous ammonia of $0.293/gallon, based on the average cost for ammonia for 2016 from the U.S. Geological Survey's Minerals Commodities Summaries for which EPA provided a weblink.[182] The U.S. Geological Survey Minerals Commodities Report currently lists the 2020 average cost for ammonia at $220/ton.[183] Thus, BP's costs of ammonia reagent were greatly overstated. Use of anhydrous ammonia is the least expensive form of the reagent and is commonly

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[176] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses), at P16-P18.
[177] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189-191.
[178] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses), at P-8.
[179] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144, Attached as Ex. 10.
[180] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses), at P-20.
[181] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses) at Attachment B.
[182] See EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[183] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 116, available at https://www.usgs.gov/centers/nmic/mineral-commodity-summaries.

used at utility installations. The State must ensure that the most cost-effective approaches to controlling NOx emissions with SCR and also that wholly unjustified and unreasonably high costs for ammonia are not used. Notably, Ecology used EPA's default cost for 29% aqueous ammonia in its SCR cost calculations.[184]

7. BP assumed an SCR would operate 8,784 hours per year (i.e., the total number of hours in a leap year) in estimating the reagent costs for SCR at the South Vacuum Heater, which clearly is in error as that could only occur once every four years. BP also assumed 8,760 hours of operation for estimating reagent costs for SCR at the #1 Hydrogen Plant North and South Reforming Furnaces. Ecology must ensure that the assumed operating hours for estimating reagent costs are consistent with the baseline emissions and baseline capacity factor assumed in each SCR cost analysis.

8. With respect to non-air quality impacts of SCR controls, BP has indicated that spent catalyst will require off-site disposal or recycling.[185] However, EPA's Control Cost Manual states that use of rejuvenated and regenerated catalyst can both reduce catalyst replacement costs and eliminate catalyst disposal costs. Ecology must ensure that the SCR cost analyses assume the most cost-effective options for catalyst replacement.

9. BP assumed it would take 7 to 10 years to implement additional NOx control strategies.[186] The company states that it would need to follow the refinery maintenance turnaround (TAR) schedule, which is 5 to 6 years per unit, but it seems very unlikely that each unit is on the same maintenance schedule and instead the maintenance schedules are likely staggered.

In its public review draft regional haze plan, Ecology presented SCR cost effectiveness evaluations for the reformer heaters, the crude heater, and the hydrogen plant (North and South furnaces).[187] Ecology's cost effectiveness analyses were based on EPA's SCR cost spreadsheet, and it appears Ecology relied on the default cost assumptions of the EPA spreadsheet (such as the cost of ammonia and catalyst replacement cost).[188] Ecology assumed 90% NOx reduction with SCR, and Ecology assumed a 25 year life and a 3.25% interest rate in amortizing capital costs of control. The cost differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and BP's are very significant, as shown in the table below. This information is from Ecology's discussion in the narrative section of the draft regional haze SIP, and additional information on Ecology's costs are included in a spreadsheet printout in Appendix P of its draft plan.

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[184] WDOE, Public Review Draft, Regional Haze Plan for the Second Implementation Period, October 2021, Appendix P at P357.
[185] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P (BP Cherry Point Four-Factor Analyses) at P-14.
[186] *Id.*
[187] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189.
[188] Based on a review of the tables with heading "EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020, Refineries Regional Haze Review – BP Cherry Point" in Appendix P of the WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at P-355 to P-361.

**Table 5. Summary from Draft Washington Regional Haze SIP: Comparison of BP's Cost Analysis to Ecology's Cost Analysis for SCR at Certain BP Cherry Point Emission Units**[189]

| BP's Capital Cost | BP's Annual Maintenance Cost | BP's Cost Effectiveness, $/ton | WDOE's Capital Cost | WDOE's Maintenance Cost | WDOE's Cost Effectiveness | NOx Reduced, tpy |
|---|---|---|---|---|---|---|
| **Reformer Heaters** | | | | | | |
| $94,809,582 | $420,048 | $24,378/ton | $9,929,730 | $49,649 | $3,101/ton | 304 tpy |
| **Crude Heater** | | | | | | |
| $94,809582 | $420,048 | $24,378/ton | $9,325,358 | $46,627 | $2,051/ton | 425 tpy |
| **Hydrogen Plant Reforming Furnaces** | | | | | | |
| $143,325,183 | $479,126 | $78,065/ton | $9,325,358 | $46,627 | $6,161/ton | 141 tpy |

BP's cost estimates are almost ten times as high as the SCR cost estimates for the same units calculated by Ecology with EPA's SCR cost spreadsheet. Ecology's analysis clearly shows that SCR at these BP Cherry Point units would be cost effective and would reduce NOx emissions by a total of 870 tons per year. Ecology states that BP did not provide the data it used to scale the cost data.[190] Thus, Ecology has found BP did not adequately support its SCR cost calculations.

Ecology did not find that the energy and non-air quality impacts of compliance with SCR should be an impediment to implementation of SCR, because the costs for the additional power needed to drive exhaust fans is included in the EPA Control Cost Manual SCR cost estimate.[191] Ecology also states that BP Cherry Point did not indicate that any equipment had a limited lifetime.[192] Ecology did state that the time necessary for compliance needed to accommodate installation during a planned shutdown to ensure reasonable costs, and Ecology states that installation of controls would likely occur in the next implementation period.[193] However, BP indicated in its four-factor submittal that currently scheduled cycle ending turnarounds for the emission units affected, which BP states vary from 2021 to 2026.[194] Thus, Ecology could ensure installation of SCR during the second implementation period and coordinate the installation with planned shutdowns at BP Cherry Point.

Ecology points out in its draft plan that the National Park Service has issued a finding to Ecology stating that emissions from BP Cherry Point "were adversely impacting air quality related values at North Cascades and Olympic National Parks."[195] Thus, Ecology should prioritize regional haze controls at the BP Cherry Point refinery to not only address regional haze but also to address visibility impairment at these parks which the National Park Service has reasonably attributed to the BP Cherry Point refinery. Ecology has found that SCR is cost effective for the

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189 Data from WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189-190 (Tables 7-8, 7-9, and 7-10).
190 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 191.
191 *Id.*
192 *Id.*
193 *Id.*
194 *Id.*, Appendix P at P-12 (BP Cherry Point Four-Factor Submittal).
195 *Id.* at 188.

reformer heaters, crude heater, and the hydrogen plant reforming furnaces to reduce NOx emissions by 90% from these emission units. Ecology should include these control requirements in its regional haze plan for the second implementation period.

### 3. Marathon Petroleum Company (MPC) Anacortes Refinery (Formerly Tesoro Refinery)

The Anacortes Refinery is currently owned by Marathon Petroleum Company (MPC) and was previously owned by Tesoro Refining & Marketing Company LLC (Tesoro, which Ecology also refers to as "Tesoro Northwest Company"[196]). Ecology calculated a Q/d value for the Tesoro Anacortes Refinery of 30.7, and it is ranked 6th highest Q/d on Ecology's list of sources it evaluated.[197] NPCA data shows that the facility likely impacts regional haze at 10 Class I areas.[198] Tesoro submitted a four-factor analysis of controls for the Anacortes facility on April 29, 2020.[199] In Ecology's review of NOx emission rates per 1,000 barrels per day (bpd) production rate at refineries nationwide, the Anacortes refinery formerly owned by Tesoro was at the highest emitter of NOx at 16.12 tons per year per 1,000 bpd production, which was two to five times as high as the NOx emissions per 1,000 bpd at all other refineries in the United States that Ecology reviewed.[200]

Tesoro submitted a four-factor analysis for FCCU and boilers and heaters greater than 40 MMBtu/hr. Specifically, Tesoro submitted a four-factor analysis for the following emission units at the refinery:

- Crude Heater 2
- Vacuum Flasher Heater
- CCU Feed Heater
- DHT Feed Heater
- Boiler 1
- Boiler 2
- Boiler 3
- NHT Feed Heater
- NHT Column C-6600 Reboiler
- CR Feed Heaters
- CO Boiler 2
- FCCU.

Tesoro only evaluated controls for NOx. The company stated that Ecology only requested evaluations of low NOx burners/ultra-low NOx burners and SCR. The following provides comments on Tesoro's cost effectiveness analyses in its Four-Factor submittal.

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196 *Id.* at 185.
197 WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
198 NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
199 *Id.*, Appendix P at P-199 through P-291.
200 *Id.* at 185-186 (Table 7-6).

*Issues with Four-Factor Analyses for Boilers and Heaters at Tesoro Refinery*

1. Tesoro did not conduct four-factor analyses for any heaters or boilers that had installed NOx controls since 2005.[201] However, none of Tesoro's heaters or boilers that it exempted from a four-factor analysis have installed controls to reduce NOx emissions. Those units that it exempted include Crude Heater 1 (Unit F-101), Crude Heater 3 (Unit F-103), CGS Column C C-113 Reboiler (Unit F-104), BenSat Column C – 6601 Reboiler (Unit F-6602), and Carbon Monoxide Boiler 2 (Unit F-302).[202] Given that SCR is such a highly effective NOx control, the state should require SCR installation for these units.

2. Tesoro used 2014 as the baseline year for cost effectiveness analysis for the various emission units, but it did not provide any analysis to show that 2014 emissions were reflective of emissions expected in 2028. EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions.[203] The use of emissions from over six years ago needs to be justified. For example, Tesoro assumed the CCU Feed Heater, Unit F-301, only operated 839 hours per year.[204] The Crude Heater 2 (Unit F-102) and the Vacuum Flash Heater (F-201) were evaluated at operational levels over 8,000 hours per year, whereas most other units were evaluated at lower operating hours in the range of 4,600-5,500 hours per year.[205] The annual hours of operation define how much pollution is emitted in a year and thus how much pollution can be decreased with a particular control being evaluated, which can greatly impact the cost effectiveness of a pollution control. Thus, the state should ensure that the assumptions are reasonable projections of emissions in 2028.

3. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Tesoro used an interest rate of 5.5%. In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

4. In the SCR cost analyses, a very high and unjustified cost of ammonia was assumed of \$900/ton.[206] No basis was cited for this cost. The company calculated a cost per gallon for 19.5% aqueous ammonia of \$3.513 per gallon.[207] Yet, EPA's SCR Control Cost Manual chapter assumes a much lower cost for 29% aqueous ammonia of \$0.293/gallon, based on the average cost for ammonia for 2016 from the U.S. Geological Survey's

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[201] *Id.*, Appendix P at P-207 (Tesoro Four-Factor Analysis).
[202] *Id.*
[203] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[204] Tesoro Four-Factor Analysis at pdf page 39 (Appendix A at F-301).
[205] WDOE, Public Review Draft, Second Regional Haze Plan, Appendix P, Tesoro Four-Factor Analysis at Appendix A in SCR cost spreadsheets for Units F-652, F-751, F-752, F-753, F-6600, F-6650/1/2/3, F-6601, and F-304.
[206] *Id.* at P-224 (Tesoro Four-Factor Analysis, Appendix A at F-102)
[207] *Id.*

Minerals Commodities Summaries for which EPA provided a weblink.[208] The U.S. Geological Survey Minerals Commodities Report currently lists the 2020 average cost for ammonia at $220/ton.[209] Thus, Tesoro's costs of ammonia reagent were greatly overstated. It is also not clear why only 19.5% aqueous ammonia was considered as a reagent. EPA's Control Cost Manual states that 29% aqueous ammonia is the more commonly used form of aqueous ammonia.[210] Use of anhydrous ammonia is the least expensive form of the reagent and is commonly used at utility installations.[211] The State must evaluate the most cost-effective approaches to controlling NOx emissions with SCR and must not use a wholly unjustified and very high cost for ammonia of $900/ton.

5. Tesoro's cost effectiveness evaluations of SCR used the EPA SCR cost spreadsheet that has been made available with its SCR Control Cost Manual chapter for all units except for the FCCU for which Tesoro used a cost estimate from a similar installation.[212] For the FCCU, only a one-page printout of an apparent spreadsheet was provided for review. The State should not accept cost effectiveness calculations without the underlying data and assumptions, so it can ensure that the cost analysis is consistent with the methodology of EPA's Control Cost Manual and that the assumptions for items such as reagent and catalyst costs are reasonable. In addition, EPA states "[i]f a cost quote or opinion prepared for one source is adopted or adapted to another source, EPA recommends the state explain in its SIP submittal how the source for which the original cost estimate was made is relevant to estimating the cost of compliance for the source in question."[213]

6. With respect to the use of EPA's cost spreadsheet for SCR, there is one entry made by Tesoro into the EPA cost spreadsheet that ultimately defines the size of the SCR reactor, and that is the "base case fuel gas volumetric flow rate factor" which is in units of $ft^3$/min-MMBtu/hr. These numbers seem very high in comparison to the values EPA uses for coal-fired boilers for which EPA defines as a constant for fuel type regardless of unit size or actual gas throughput.[214] Tesoro's fuel gas volumetric flow rate factors for each combustion turbine are roughly a factor of 100 higher than the fuel gas volumetric flow rate factors of 484-547 cubic $ft^3$/min-MMBtu/hour (depending on coal type) used by EPA in its SCR cost spreadsheet for coal-fired boilers.[215] If the state may rely on that information, Ecology must request documentation and justification for the base case fuel gas volumetric flow rate factors used by Tesoro.

7. Tesoro assumed NOx control efficiencies across the SCRs of 90%-96% for most boilers and heaters, with the exception of Boiler 3 (F-753) for which Tesoro only assumed a

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208 See EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
209 U.S. Geological Survey, Minerals Commodities Summaries 2020, at 116, available at https://www.usgs.gov/centers/nmic/mineral-commodity-summaries.
210 EPA, Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 15.
211 *Id.* at pdf page 5.
212 Tesoro Four-Factor Analysis at Appendix A.
213 U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 32.
214 EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 59, Table 2.6.
215 Compare values used for flue gas volumetric flow rate factors in Draft Washington Regional Haze Plan, Appendix P, in Appendix A of Tesoro's Four-Factor Analyses to Table 2.6 of EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction.

control efficiency of 75%.[216] No justification was provided for assuming a much lower than typical NOx removal rate across the SCR.

8. With respect to the cost evaluations for ULNB for the heaters and boilers, Tesoro only assumed a 20-year life of controls in determining the amortizing the capital costs of control.[217] There was no basis provided for only assuming a 20-year life of ULNB.[218] If ULNB only have a life of 20-years, then the State should not exempt any boiler or heater from a four-factor analysis if it has installed controls by 2005 as claimed by Tesoro,[219] because the low NOx burners installed at Crude Heater 1 (F-101), Crude Heater 3 (F-103), CGS Column C-113 Reboiler (F-104), BenSat Column C-6601 Reboiler (F-6602), and Carbon Monoxide Boiler 1 (F-302)[220] will be at the end of their useful lives during the second planning period. Ultra-low NOx burners should have a useful life 25-30 years or more. In evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[221] In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR.[222] Thus, the State should not allow the use of a useful life of an ULNB any less than 25 years for the Tesoro units.

9. Tesoro did not provide justification for the NOx emission rate for the ULNBs. For most units, Tesoro assumed a 0.04 lb/MMBtu achievable NOx rate with ULNB.[223] Yet, the CGH Heater F-104, which has ULNBs,[224] is subject to a NOx limit of 0.035 lb/MMBtu.[225] The State should thus require an evaluation of ULNBs to meet a similar 0.035 lb/MMBtu NOx rate. For Units F-751 and F-752 which are boilers, a much higher NOx rate of 0.11 lb/MMBtu was assumed for ULNB.[226] Yet, Unit F-753 which is also a boiler of similar size to Units F-751 and F-752 but which has been retrofitted with low NOx burners and internal flue gas recirculation (IFGR),[227] Tesoro assumed a NOx rate of 0.04 lb/MMBtu in its evaluation of SCR cost effectiveness[228] which presumably reflects its current emission rate. Thus, Tesoro's evaluation of ULNBs for Units F-751 and F-752

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[216] WDOE, Public Review Draft, Second Regional Haze Plan, Appendix P, Tesoro Four Factor Analysis, Appendix A, SCR spreadsheet printouts.
[217] *Id.* at P-284 to P-291.
[218] *Id.* at P-219.
[219] *Id.* at P-207.
[220] *Id.*
[221] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).
[222] WDOE, Public Review Draft, Second Regional Haze Plan, Appendix P, at P-15 (BP Cherry Point Four-Factor Analysis).
[223] *Id.,* Appendix P at P-284 to P-291 (Tesoro Four-Factor Analyses).
[224] *Id.* at P-207 to P-208.
[225] January 26, 2010 Air Operating Permit #013R1 for Tesoro Refining and Marketing Company at 72 (Permit Term 5.2.13).
[226] WDOE, Public Review Draft, Second Regional Haze Plan, Appendix P at P-287 to P-288 (Tesoro Four-Factor Analyses).
[227] *Id.* at P-211.
[228] *Id.*at P-262.

should have evaluated cost effectiveness to meet a similar NOx rate as has been achieved at Unit F-753 with a similar control.

10. Tesoro did not evaluate the cost effectiveness of the most effective control – ULNB plus SCR.

In its public review draft regional haze plan, Ecology presented SCR cost effectiveness evaluations for seven emission units at the Anacortes refinery (FCCU, F102 Crude Heater, F201 Vacuum Flasher Heater, F6650 CAT Reformer Heater, F751 Main Boiler, and F752 Main Boiler).[229] Ecology's cost effectiveness analyses were based on EPA's SCR cost spreadsheet, and it appears Ecology relied on the default cost assumptions of the EPA spreadsheet (such as the cost of ammonia and catalyst replacement cost).[230] Ecology assumed 90% NOx reduction with SCR, and Ecology assumed a 25 year life and a 3.25% interest rate in amortizing capital costs of control. The cost differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and Tesoro's are very significant, as shown in the tables below. Note that Ecology refers to the cost estimates as "MPC" cost estimates, but the cost estimates are from Tesoro's April 20, 2020 Four-Factor Analysis of controls, which is in Appendix P of Ecology's draft regional haze plan.

Table 6 shows the differences in Tesoro's and Ecology's calculated capital costs and annual maintenance costs for SCRs at the FCCU and at the F102 Crude Heater, to show how significant the cost differences are between Tesoro and Ecology. This information was provided in and discussed in Ecology's draft regional haze plan.[231] Note that Ecology states that Tesoro's (MPC's) cost is based on SNCR controls at 60% NOx removal efficiency.[232] However, that appears to be in error. A review of Tesoro's four-factor analysis shows that the Tesoro cost numbers (labeled as MPC cost numbers in the draft plan) are reflective of SCR costs (not SNCR) to achieve 89.7% NOx control (not 60% control) and 833.10 tons per year of NOx reduction.[233]

Table 7 further below shows the difference in cost of SCR per ton of NOx removed between Tesoro and Ecology's cost analyses for all other units for which Ecology evaluated SCR costs. The differences in capital costs and maintenance costs of the units other than the FCCU and the F102 Crude Heater were not discussed in the narrative section of Ecology's draft plan but are provided in Appendix P of Ecology's draft second regional haze plan.[234] The differences in calculated SCR costs/ton of NOx removed make clear that Tesoro's costs are significantly higher than the costs calculated by Ecology using the EPA SCR cost spreadsheet provided with EPA's Control Cost Manual.

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229 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 199.

230 Based on a review of the tables with heading "EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020, Refineries Regional Haze Review – Tesoro" in Appendix P of the WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at P-347 to P-354.

231 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021 at 199-200.

232 *Id.* at 200.

233 *Id.*, Appendix P at P-223.

234 Ecology's specific cost data in Appendix P is difficult to ascertain from what appear to be printed tables from a spreadsheet that span several pages.

**Table 6. Summary from Draft Washington Regional Haze SIP, SCR Cost Analysis for the FCCU and the F102 Crude Heater at the Anacortes Refinery – Comparison of Tesoro's (MPC's) Cost Analysis to Ecology's Cost Analysis**[235]

| Tesoro's Capital Cost | Tesoro's Maintenance Costs ($/yr) | Tesoro's Cost Effectiveness, $/ton | WDOE's Capital Cost | WDOE's Maintenance Costs ($/yr) | WDOE's Cost Effectiveness | NOx Reduced, tpy |
|---|---|---|---|---|---|---|
| **FCCU** | | | | | | |
| $114,030,975 | $570,155 | $14,381/ton | $10,286,436 | $51,432 | $1,159/ton | 843.3 tpy |
| **F102 Crude Heater** | | | | | | |
| $20,876,000 | $104,380 | $16,086/ton | $5,084,927 | $25,425 | $2,962/ton | 147.6 tpy |

**Table 7. Comparison of SCR Cost Effectiveness as Calculated by Tesoro to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Anacortes Refinery**[236]

| Anacortes Refinery Emission Unit | Tesoro's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| FCCU | $14,381/ton | $1,159/ton | 843.3 tpy |
| F102 Crude Heater | $16,086/ton | $2,962/ton | 147.6 tpy |
| F201 Vacuum Heater | $35,276/ton | $7,589/ton | 57.6 tpy |
| F6650 CAT Reformer Heater | $21,196/ton | $3,736/ton | 117 tpy |
| F6651 CAT Reformer Heater | $21,196/ton | $3,520/ton | 124.2 tpy |
| F751 Main Boiler | $10,060/ton | $2,159/ton | 202.5 tpy |
| F752 Main Boiler | $10,513/ton | $2,570/ton | 170.1 tpy |

For SCR at the FCCU, Tesoro's cost estimates are roughly ten times as high as the SCR cost estimates for the same units calculated by Ecology with EPA's SCR cost spreadsheet. Ecology's analysis clearly shows that SCR at the FCCU would be cost effective at $1,159/ton and would reduce NOx emissions by 843 tons per year. For the F102 Crude heater, Ecology states that MPC (Tesoro) "incorrectly changed the default value for the Ft$^3$/min-MMBtu/hr input to the EPA Control Cost manual for all their determinations other than the FCCU."[237] That issue is discussed in Comment 6 above. Thus, Ecology has found Tesoro (MPC) did not adequately support its SCR cost calculations. Ecology's SCR cost estimates are much lower than Tesoro's (MPC's) for all of the emission units listed in Table 6 above. Assuming Ecology is using a $6,300/ton cost effectiveness threshold for refineries as it has proposed for the pulp and paper

[235] Data from WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 189-190 (Tables 7-8, 7-9, and 7-10).
[236] *Id.* at 199.
[237] *Id.* at 200.

industry,[238] SCR must be considered a cost effective control for all units listed in Table 6 above except the F201 Vacuum Heater. Those cost effective SCR installations could collectively reduce NOx emissions from the Anacortes Refinery by 1,604.7 tons per year.

Ecology did not find that the energy and non-air quality impacts of compliance with SCR should be an impediment to implementation of SCR, because the costs for the additional power needed to drive exhaust fans is included in the EPA Control Cost Manual SCR cost estimate.[239] Ecology also states that MPC (Tesoro) did not indicate that any equipment had a limited lifetime.[240] Ecology did state that the time necessary for compliance needed to accommodate installation during a planned shutdown to ensure reasonable costs, and Ecology states that installation of controls would likely occur in the next implementation period.[241] However, if Ecology met the requirements of EPA's regional haze regulations and included final determinations to require SCR in this regional haze plan for the second implementation period, many of these SCR installations could occur during the second implementation period and be coordinated with maintenance outages at the Anacortes refinery.

Ecology points out in its draft plan that the Federal Land Managers have "made comments regarding the impacts to the Olympic [National Park] Class I area" in the context of commenting on a PSD permit for the Tesoro Anacortes Refinery.[242] Indeed, the National Park Service's 2017 comments stated that Tesoro Anacortes refinery contributed significantly to visibility impairment at North Cascades National Park and at Olympic National Park, and the Park Service noted that the refinery should be considered for controls in the next regional haze plan.[243] It is not clear whether these comments constituted a determination of reasonably attributable visibility impairment. Nonetheless, Ecology should prioritize regional haze controls at the MPC Anacortes refinery to not only address regional haze but also to address visibility impairment at Olympic National Park attributable to the refinery. Ecology has found that SCR is cost effective for the FCCU, CAT reformer heaters, main boilers, and the F102 crude heater. Ecology should include these control requirements in its regional haze plan for the second implementation period.

#### 4. Shell Puget Sound Refinery

The Shell Puget Sound Refinery is another refinery located near Anacortes, Washington. Ecology calculated a Q/d value for the BP Cherry Point facility of 24.5.[244] NPCA data shows that the facility can potentially impact regional haze at 8 Class I areas.[245] Shell submitted a four-factor analysis evaluating NOx controls for its FCCU and boilers and heaters greater than 40

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[238] *Id.* at 182.
[239] *Id.* at 201.
[240] *Id.*
[241] *Id.*
[242] *Id.* at 198.
[243] April 27, 2017 Letter from the National Park Service to the Washington Department of Ecology at 4, attached as Ex. 11.
[244] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
[245] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.

MMBtu/hr. The company stated that Ecology only requested evaluations of LNB/ULNB and SCR.[246] The units that Shell evaluated NOx controls for include the following:

- Vacuum Pipe Still (VPS) Charge Heater 1
- VPS Charge Heater 2
- Vacuum Tower Heater
- Delayed Coking Unit (DCU) Charge Heater
- Hydrotreater Unit 1 (HTU1) Charge Heater
- HTU1 Fractionator Reboiler
- HTU2 Stripper Reboiler
- Hydrotreater Unit 2 (HTU2) Fractionator Reboiler
- Catalytic Reforming Unit #2 (CRU2) Charge Heater
- CRU2 Interheater #1
- CRU2 Stabilizer Reboiler
- Erie City Boiler #1
- Cogen Gas Turbine Generator (GTG) Heat Recover Steam Generator (HRSG) with duct burners (GTG1, GTG2, and GTG3)

Shell states that Ecology narrowed the request to only LNB/ ULNB and SCR. Shell analyzed the cost effectiveness of LNB/ULNB and SCR for these units.

Shell concludes that SCR is not a cost-effective control for NOx emissions at the refinery.[247] Shell indicates that the cost-effectiveness of LNB is much lower than those of SCR. However, Shell argues that a more thorough, unit-specific evaluation by vendors will be required to determine if the installation of low-NOx is technically feasible and cost-effective.[248] It must be noted that several of the units listed above already have LNBs installed, as do some additional units at the Shell refinery which were not evaluated in the four-factor analysis. The following provides comments on Shell's cost effectiveness analyses in its Four-Factor submittals.

*Issues with Four-Factor Analyses for Shell Puget Sound Refinery*

1. Shell used 2019 emissions as baseline and stated that 2019 "is representative of the anticipated actual emissions in the near future."[249] Shell identifies the 2019 baseline emissions for NOx as 592.6 tons per year for "all applicable units."[250] It is not clear whether this includes all NOx emissions at the source, but emissions data provided in Ecology's draft second regional haze implementation plan for the years 2011 through 2018 show much higher NOx emissions, ranging from 1,054 tons per year to 1,409 tons per year.[251] EPA states that generally, baseline emissions for pollution control analyses should be based on a recent period of historical emissions. If a company is proposing that 2028 emissions will be significantly lower than past historical emissions, there must be a documented basis for that assumption such as enforceable requirements or a

[246] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-138 (Shell Puget Sound Refinery Four-Factor Analysis).
[247] *Id.* at P-148.
[248] *Id.*
[249] *Id.* at P-142.
[250] *Id.*
[251] *Id.* at 84 (Table 4-8).

documented commitment to participate in energy efficiency or renewable energy programs.[252] Ecology has indicated that 2014 emissions of 1,230 tons per year are the representative baseline NOx emissions and the expected 2028 emissions for the Shell refinery.[253] Given that Shell has not provided documentation to indicate that the much lower NOx baseline of 592.6 tons per year that it relied on as reflective of 2028 emissions is based on enforceable limits or other documented and verifiable commitments, the state is justified in assuming 2014 NOx emissions are reflective of 2028 emissions for the Shell Puget Sound Refinery.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Shell used an unreasonably high interest rate of 7%.[254] In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units except the Erie City Boiler, the Shell cost effectiveness analyses assumed a 20-year life of controls.[255] No justification has been included in Shell's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[256] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years.[257] In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR.[258] Thus, the State should not allow the use of a 20-year useful life of a LNB or an SCR to be assumed in the cost effectiveness analyses for any of the Shell units, with one possible exception being the Erie City Boiler 1 (ECB1).

4. With respect to the remaining useful life of the Erie City Boiler 1, Shell provided brief information for this boiler that "substantial upgrades will be required to replace the boiler's refractory and the boiler skin" and that "the remaining useful life of the unit is

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[252] *See* U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 29.
[253] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 84 (Table 4-8).
[254] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-146.
[255] *Id.* at P-196.
[256] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).
[257] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[257] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 80.
[258] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P4, P-15, and Attachment B of the BP Cherry Point Four-Factor Analysis.

expected to be less than 10 years."[259] The company assumed 8 years in its four-factor analysis for the Erie City Boiler.[260] Importantly, Shell did not indicate that it would be retiring Erie City Boiler 1. If Shell plans on these substantial upgrades to the boiler, then Ecology should not consider this boiler as having a shortened remaining useful life in the NOx control cost effectiveness analyses. If the company is planning to retire and replace the boiler within the next 8 years, then Ecology should impose an enforceable retirement date for the boiler.[261] Ecology should also require that any replacement boiler should, at the very least, be equipped with state-of-the-art NOx controls. The Erie City Boiler 1 currently has no controls and, at 182.4 tons per year, has the highest emissions of NOx of any of the units evaluated in Shell's four-factor analysis. Ecology should not allow this unit or its replacement to avoid controls because it is either going to be reconstructed or removed from service in the next 8-10 years.

5. In its four-factor analysis, Shell assumed that LNB would only achieve a NOx emission rate of 0.06 lb/MMBtu. Shell provided no justification for assuming such a high NOx emission rate with LNB. As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[262] In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control.[263] It is also worth noting that Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[264]

6. For SCR, Shell used the EPA SCR cost spreadsheet made available with EPA's recent update to its SCR chapter of the Control Cost Manual. However, Shell applied a very high retrofit factor of 1.5 to each SCR evaluation, without providing any justification for any retrofit factor much less a retrofit factor that increases SCR costs by 50%. The cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology must scrutinize the use of any retrofit factor. EPA's SCR cost spreadsheet already adds a retrofit factor of 20% compared to the cost of SCR installation at a new unit for SCR retrofits at existing units.[265] EPA's Control Cost Manual states that higher retrofit factors than 1 can be used "provided the reasons for using a higher retrofit factor are appropriate <u>and fully documented</u>."[266] No unit-specific documentation of the justification for higher SCR retrofit factors was included in Shell's four-factor submittal.

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[259] *Id.* at P-148 (Shell Four-Factor Analyses).
[260] *Id.*
[261] *See* EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 20, which states that a state "may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028."
[262] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144. (Ex. 10.)
[263] May 5, 2015 Air Operating Permit AOP 014R1M1 for Shell Puget Sound Refinery at 13 and 127.
[264] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-222 to P-291 (Appendix A of Tesoro Four-Factor Analysis).
[265] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 66.
[266] *Id.* (emphasis added)

7. Shell appears to have assumed that that the gas stream of each heater/boiler would need to be reheated to accommodate SCR.[267] However, Shell did not provide any data on each of the units for which these costs were included in the SCR cost effectiveness to indicate that reheating the gas stream to accommodate SCR operation is necessary. Ecology must request further information before it can justify the inclusion of these costs for reheating the gas stream for each of the emission units at the Shell refinery.

In its public review draft regional haze plan, Ecology presented SCR cost effectiveness evaluations for three emission units at Shell Puget Sound Refinery (Boiler #1 Erie City- 31G-F1, FCCU Regenerator Unit, and CRU2 Heater and Interheaters).[268] Ecology's cost effectiveness analyses were based on EPA's SCR cost spreadsheet, and it appears Ecology relied on the default cost assumptions of the EPA spreadsheet (such as the cost of ammonia and catalyst replacement cost).[269] Ecology assumed 90% NOx reduction with SCR, and Ecology assumed a 25 year life and a 3.25% interest rate in amortizing capital costs of control. The cost differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and Shell's are significant, as shown in the table below.

Table 8 shows the differences in Shell's and Ecology's calculated capital costs and annual maintenance costs for SCRs at the Boiler #1 Erie City, FCCU Regenerator Unit, and the CRU2 Heater, to show how significant the cost differences are between Shell and Ecology. This information was provided in and discussed in Ecology's draft regional haze plan.[270]

**Table 8. Comparison of SCR Cost Effectiveness as Calculated by Shell to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Shell Puget Sound Refinery[271]**

| Puget Sound Refinery Emission Unit | Shell's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| Erie City Boiler 1 | $12,511/ton | $2,441/ton | 179 tpy |
| FCCU Regenerator Unit | Not Evaluated | $1,948/ton | 521 tpy |
| CRU2 Charge Heater/Interheaters | $10,813/ton | $6,346/ton | 69 tpy |

For SCR at Erie City Boiler 1, Shell's cost estimates are more than five times as high as the SCR cost estimates for the same units calculated by Ecology with EPA's SCR cost spreadsheet.

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267 WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P Shell Four-Factor Analysis at Appendix B.
268 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 195.
269 Based on a review of the tables with heading "EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020, Refineries Regional Haze Review – Tesoro" in Appendix P of the WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at P-347 to P-354.
270 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021 at 195-196.
271 *Id.* at 195.

Ecology did not take into account a shortened remaining useful life of the boiler in its SCR cost effectiveness analysis, as Shell did. Ecology states "With an eight-year lifetime, a requirement for the boiler to be retired after this period would be justified and the boiler should be required to decommission. Any new boiler brought in to replace it would need to go through the permitting process as a new source."[272] Ecology stated in the draft regional haze plan that it will work with the Northwest Clean Air Agency "to have a regulatory order on the boiler to shut down by January of 2028."[273] It is not clear why such a regulatory order has not been established and included as part of this regional haze plan. Ecology should not allow the Erie City boiler to avoid regional haze controls without making the decommissioning and the requirement to obtain a permit for any replacement boiler as a new source (meaning not allowing a replacement boiler to "net out" of permitting review) enforceable requirements.

Shell did not evaluate controls for the FCCU regenerator unit, but Ecology did and found that SCR at that unit would be cost effective at $1,948/ton and would reduce NOx by 521 tpy. Ecology's analysis clearly shows that SCR at the FCCU would be cost effective. Ecology's analysis of SCR cost effectiveness at the CRU#2 heater and interheaters also shows that the cost effectiveness is reasonable.

Ecology did not find that the energy and non-air quality impacts of compliance with SCR should be an impediment to implementation of SCR, because the costs for the additional power needed to drive exhaust fans is included in the EPA Control Cost Manual SCR cost estimate.[274] Ecology did not indicate that Shell had stated that any equipment had a limited lifetime other than Erie City Boiler 1.[275] Ecology did state that the time necessary for compliance needed to accommodate installation during a planned shutdown to ensure reasonable costs, and Ecology states that installation of controls would likely occur in the next implementation period.[276] However, if Ecology met the requirements of EPA's regional haze regulations and included final determinations to require SCR in this regional haze plan for the second implementation period, these SCR installations could occur during the second implementation period and be coordinated with maintenance outages at the Shell Puget Sound refinery. Ecology found that the Shell Puget Sound Refinery had the second highest NOx emissions per 1,000 bpd production of all of the eighty-four refineries nationwide that it evaluated.[277] Ecology has found that SCR is cost effective for Erie City Boiler 1, the FCCU, regenerator unit, and the CRU #2 heater and interheaters. Ecology should include these control requirements (or, for Eric City Boiler 1, a requirement to be decommissioned by 2028) in its regional haze plan for the second implementation period.

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[272] *Id.* at 195-196.
[273] *Id.* at 197.
[274] *Id.* at 197.
[275] *Id.*
[276] *Id.*
[277] *Id.* at 185.

### 5. Phillips 66 Ferndale Refinery

Ecology calculated a Q/d value for the BP Cherry Point facility of 10.9.[278] NPCA data shows that the facility impacts regional haze at 5 Class I areas.[279] Phillips 66 provided four-factor analyses of NOx controls for the following emission units at its Ferndale Refinery:[280]

- Crude Heater
- Crude Heater
- Alky Heater
- Reformer - Pretreater heater
- Reformer heater
- Reformer heater
- Reformer heater
- Reformer heater
- #1 Boiler
- #2 Boiler
- #3 Boiler
- DHT Heater
- S-Zorb Heater.

Phillips 66 states that Ecology narrowed the request to only LNB/ ULNB and SCR.[281] Phillips 66 analyzed the cost effectiveness of LNB/ULNB and SCR for these units and concluded that neither SCR nor LNB are cost-effective control for NOx emissions reductions at the refinery.[282] The following provides comments on the four-factor analyses submitted by Phillips 66.

*Deficiencies and shortcomings in the Phillips 66 Analyses are as follows:*

1. Phillips 66 used a five-year average of annual emissions from 2014-2018 as baseline emissions.[283] EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions. Ecology has indicated that 2014 emissions of 723 tons per year are the representative baseline NOx emissions and the expected 2028 emissions for the Phillips 66 Ferndale

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[278] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 161.
[279] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[280] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P37 to P-85 (Phillips 66 June 2020 Four-Factor Analysis). Note that Phillips 66 originally submitted its four-factor analysis in April of 2020 (also in Appendix P), but it revised the analysis in June 2020 because it claimed that "the burners currently in operation for the alkylation heater (17F-1) and the DHT heater (33F-1) are considered low-NOx burners," and thus Phillips 66 excluded LNBs as a control to be evaluated for these units. *See* June 29, 2020 cover letter to Phillips 66 June 2020 Four-Factor Analysis.
[281] *Id.* at P-43.
[282] *Id.*
[283] *Id.* at P-49.

refinery.[284] The state should ensure that the emission assumptions are reasonable projections of emissions in 2028.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Phillips 66 used an unreasonably high interest rate of 7%. In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units, the Phillips 66 cost effectiveness analyses assumed a 20-year life of controls.[285] No justification has been included in Phillip 66's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[286] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years. In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR. Thus, the State should not consider a useful life of a LNB or an SCR to be less than 25 years in the cost effectiveness analyses for any of the Phillips 66 units.

4. Phillips 66 assumed high NOx rates with LNB in the range of 0.09 to 0.23 lb/MMBtu.[287] As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[288] In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control.[289] It is also worth noting that Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[290] Moreover, the #1 boiler, the DHT Heater, and the S-Zorb heater at the Phillips 66 refinery, which all have LNB, have baseline NOx emission rates in the range of 0.031 to 0.042 lb/MMBtu, per Phillips 66 SCR cost effectiveness analysis.[291]

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[284] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, at 84 (Table 4-8).
[285] *Id.* at P-78 (Appendix B of Phillips 66 June 2020 Four-Factor Analysis).
[286] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natural gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944, 18953, 18960 (Apr. 8, 2015).
[287] *Id.*
[288] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144. (Ex. 10).
[289] May 5, 2015 Air Operating Permit AOP 014R1M1 for Shell Puget Sound Refinery at 13 and 127, available at https://nwcleanairwa.gov/?wpdmdl=6716.
[290] WDOE, Public Review Draft, Regional Haze Plan for Second Implementation Period, October 2021, Appendix P at P-222 to P-291 (Appendix A of Tesoro Four-Factor Analysis).
[291] *Id.* at P-78 to P-84.

5. Phillips 66 assumed continual operation every hour of the year (i.e., 8,760 hours per year – 100% capacity factor) in assessing reagent and other operational expenses of SCR.[292] Unless the company demonstrates that its emitting units operated 8,760 hours per year during the baseline period, this assumption results in overstated operational costs.

6. Phillips 66 included the same dollar amount for construction and management costs, contingencies, and escalation for every SCR cost analysis. Specifically, the company included costs of $3,841,150 for construction and management, $1,323,000 for contingencies, and $168,300 for escalation for each SCR cost analysis.[293] These were all identified as "indirect capital costs."[294] Such costs are typically scaled to the size of the unit, but these costs clearly have not been scaled. For many units, these costs exceed the costs of the SCR and the direct installation costs. In addition, to the extent these costs include owner's costs, such as the costs for owner activities to oversee the project regarding engineering, management, and procurement, or to fund the project, such costs must be excluded from the cost effectiveness analysis. EPA does not allow owner's costs to be included in cost effectiveness analyses under the Control Cost Manual.[295]

In its public review draft regional haze plan, Ecology presented SCR cost effectiveness evaluations for two emission units at Phillips 66 Refinery (Crude Heater 1F-1 and the FCCU/CO Boiler).[296] Ecology's cost effectiveness analyses were based on EPA's SCR cost spreadsheet, and it appears Ecology relied on the default cost assumptions of the EPA spreadsheet (such as the cost of ammonia and catalyst replacement cost).[297] Ecology assumed 90% NOx reduction with SCR, and Ecology assumed a 25 year life and a 3.25% interest rate in amortizing capital costs of control. The cost differences between Ecology's cost estimates based on EPA's Control Cost Manual Spreadsheet and Phillips 66's cost estimates are significant, as shown in the table below.

Table 9 shows the differences in Phillip 66's and Ecology's calculated capital costs and annual maintenance costs for SCRs at the Crude Heater 1F-1, demonstrating how significant the cost differences are between Shell and Ecology. Table 9 also shows Ecology's cost effectiveness for SCR at the FCCU/CO Boiler. Phillips 66 did not evaluate any additional controls for the FCCU because in 2006, the company modified the unit to install enhanced selective noncatalytic reduction (ESNCR).[298] Ecology evaluated SCR for the FCCU because "FCC units are a large

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[292] *Id.* at P-78 to P-84.
[293] *Id.* at P-81.
[294] *Id.*
[295] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 65.
[296] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 192-193.
[297] Based on a review of the tables with heading "EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020, Refineries Regional Haze Review – Phillips 66" in Appendix P of the WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at P-369 to P-375.
[298] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, at 193

source of NOx emissions at refineries that have them."[299] Further, the addition of a catalytic reactor would work in concert with the ammonia injection system of the existing SNCR, and thus SCR would not be incompatible with the existing ESNCR system.

**Table 9. Comparison of SCR Cost Effectiveness as Calculated by Phillips 66 to SCR Cost Effectiveness Calculated by Ecology for Certain Emission Units at the Phillips 66 Refinery[300]**

| Phillips 66 Refinery Emission Unit | Phillips 66's Cost Effectiveness, $/ton | WDOE's Cost Effectiveness, $/ton | NOx Reduced with SCR, tpy |
|---|---|---|---|
| Crude Heater 1F-1 | $12,225/ton | $2,640/ton | 166 tpy |
| FCCU/CO Boiler | Not Evaluated | $3,954/ton | 247 tpy |

For SCR at Crude Heater 1F-1, Phillips 66's cost estimates are more than five times as high as the SCR cost estimate for the same unit calculated by Ecology with EPA's SCR cost spreadsheet. Ecology commented that Phillips 66 did not supply the data they used to scale the SCR cost data.[301] Thus, Ecology has found BP did not adequately support its SCR cost calculations.

Phillips 66 did not evaluate controls for the FCCU/CO Boiler, but Ecology did and found that SCR at that unit would be cost effective at $3,954/ton and would reduce NOx by 247 tpy. Ecology's analysis of SCR cost effectiveness at the Crude Heater 1F-1 also shows that the control is cost effective.

Ecology did not find that the energy and non-air quality impacts of compliance with SCR should be an impediment to implementation of SCR, because the costs for the additional power needed to drive exhaust fans is included in the EPA Control Cost Manual SCR cost estimate.[302] Ecology did not indicate that Phillips 66 had stated that any equipment had a limited lifetime.[303] Ecology did state that the time necessary for compliance needed to accommodate installation during a planned shutdown to ensure reasonable costs, and Ecology states that installation of controls would likely occur in the next implementation period.[304] However, if Ecology met the requirements of EPA's regional haze regulations and included final determinations to require SCR in this regional haze plan for the second implementation period, these SCR installations could occur during the second implementation period and be coordinated with maintenance outages at the Phillips 66 refinery. Ecology found that the Phillips 66 Refinery had the fifth highest NOx emissions per 1,000 bpd production of all of the eighty-four refineries nationwide that it evaluated.[305] Ecology has found that SCR is cost effective for Crude Heater 1F1 and the

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299 *Id.*
300 *Id.* at 192-193.
301 *Id.* at 193.
302 *Id.* at 193.
303 *Id.*
304 *Id.*
305 *Id.* at 185.

FCCU/CO boiler. Ecology should include these control requirements in its regional haze plan for the second implementation period.

### 6. U.S. Oil & Refining Company – Tacoma Refinery

U.S. Oil & Refining (U.S. Oil) owns a refinery in Tacoma. According to Ecology, the facility has a Q/d value of 3.2.[306] U.S. Oil submitted a four-factor analysis of NOx controls for the following emission units:[307]

- Package Steam Boiler B-4
- Package Steam Boiler B-5
- Process Heater H-11.

U.S. Oil states that Ecology narrowed the request to only LNB/ ULNB and SCR.[308] U.S. Oil analyzed the cost effectiveness of LNB/ULNB and SCR for these units and concluded that neither SCR nor LNB are cost-effective control for NOx emissions reductions at the refinery.[309]

*Deficiencies and shortcomings in the U.S. Oil Four-Factor Analyses are as follows:*

1. Rather than using a level of baseline emissions based on historical emissions at the emission units of the Tacoma refinery, U.S. Oil states that it is "implementing changes during the refinery's upcoming turnaround in early 2021 that will add significantly to heat recovery, thereby reducing the fired duties of these sources."[310] Specifically, the baseline NOx emissions assumed for the three emission units evaluated are as follows:

| | |
|---|---|
| Unit B-4 (Package Steam Boiler) | 24.96 tpy NOx |
| Unit B-5 (Package Steam Boiler) | 10.39 tpy NOx |
| Unit H-11 (Process Heater) | 31.56 tpy NOx[311] |

Ecology should request or make public how U.S. Oil's projection of future NOx emissions from these units compares to recent annual NOx emissions from these emission units.

EPA's regional haze guidance states with respect to the baseline control scenario for the control analysis that:

> Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one

[306] *Id.* at 162 (Table 7-1).
[307] *Id.*, Appendix P at P-292 to P-339 (U.S. Oil Four-Factor Analysis).
[308] *Id.* at P-297.
[309] *Id.* at P-297 to P-298.
[310] *Id.* at P-303.
[311] *Id.*

> reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another.[312]

Ecology should thus require that U.S. Oil identify the details of its changes, including providing verifiable information to quantify its projection of the future NOx emissions of these units. Further, Ecology must evaluate whether the changes at the refinery should be made into enforceable requirements, so as to ensure the refinery's continued operation at these emission rates throughout the second planning period and beyond.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. U.S. Oil used an unreasonably high interest rate of 7%.[313] In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units, the U.S. Oil cost effectiveness analyses assumed a 20-year life of controls.[314] No justification has been included in U.S. Oil's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[315] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years. In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR. Thus, the State should not allow the use of a useful life of a LNB or an SCR to be assumed in the cost effectiveness analyses for any of the U.S. Oil units.

4. U.S. Oil assumed NOx rates with LNB in the range of 0.060 to 0.072 lb/MMBtu. As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower. In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control. It is also worth noting that Tesoro evaluated

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[312] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[313] WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P at P-337.
[314] *Id.* at P-308.
[315] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).

LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.

5. U.S. Oil applied a 1.5 retrofit factor to the costs for both ULNB and for SCR.[316] This is a very high retrofit factor which essentially increases the capital costs of controls by 50%. Yet, U.S. Oil did not provide unit-specific information to justify the 1.5 retrofit factor applied to each ULNB and each SCR evaluation. With respect to SCR, it must be noted that the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology must scrutinize the use of any retrofit factor in U.S. Oil's SCR cost estimates using EPA's SCR cost spreadsheet. EPA's SCR cost spreadsheet already adds a retrofit factor of 20% compared to the cost of SCR installation at a new unit for SCR retrofits at existing units. EPA's Control Cost Manual states that higher retrofit factors than 1 can be used "provided the reasons for using a higher retrofit factor are appropriate and fully documented." No unit-specific documentation of the justification for higher SCR retrofit factors was included in U.S. Oil's four-factor submittal. With respect to the 1.5 retrofit factor applied to the cost effectiveness evaluation of ULNBs, U.S. Oil states this factor was included "to account for the additional challenges of retrofitting a low-NOx burner in an existing heater."[317] This is not sufficient documentation to justify a retrofit factor, especially such a high retrofit factor.

6. U.S. Oil states that SCR will require flue gas reheating.[318] However, U.S. Oil did not provide any data on each of the units for which these costs were included in the SCR cost effectiveness to indicate that the current exhaust gas stream would necessitate reheating to accommodate effective SCR operation. Ecology must request further information to justify the inclusion of these costs for reheating the gas stream for each of the emission units at the Tacoma refinery before it takes such costs into consideration.

As it did with the other refineries, Ecology evaluated SCR cost effectiveness using EPA's SCR cost calculation spreadsheet made available with its Control Cost Manual for the Heater H-11. Ecology found that cost effectiveness of SCR would be $15,612/ton, which was lower than U.S Oil's calculated cost effectiveness of $18,649/ton, but Ecology still found that SCR was not cost effective for this heater.[319] However, as discussed in Comment 1 above, U.S. Oil assumed a lower baseline for its cost analysis because it is "implementing changes during the refinery's upcoming turnaround in early 2021 that will add significantly to heat recovery, thereby reducing the fired duties of these sources."[320] Ecology should require that U.S. Oil identify and verify the details of its changes, and Ecology should determine if it is necessary to make such changes in emissions into enforceable requirements.

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316 WDOE, Public Review Draft, Second Regional Haze Plan, October 2021, Appendix P at P-307 and at P-337 (Table B-2).
317 *Id.* at P-337 (Table B-2).
318 *Id.* at P-308.
319 *Id.* at 202.
320 *Id.* at P-303.

## B. Four-Factor Analyses for the Pulp and Paper Mills

Ecology requested four-factor controls analyses for seven pulp and paper mills. The Northwest Pulp & Paper Association (NWPPA) submitted four-factor analyses for several emission units associated the following six pulp and paper mills:

- Nippon Dynawave Packaging Company Longview
- Georgia-Pacific Consumer Operations, LLC (GP Camas)
- WestRock Longview, LLC
- WestRock PC, LLC Tacoma
- Port Townsend Paper Corporation
- Packaging Corporation of America (PCA) Wallula.[321]

Cosmo Specialty Fibers submitted a separate four-factor analysis of controls.[322]

It appears that Ecology did not request or conduct a four-factor analysis for the McKinley Paper Plant which is a pulp and paper plant and for which it identified a Q/d value of 83.1, which was the second highest Q/d value of all facilities evaluated by Ecology.[323] Ecology must conduct a four-factor analysis of controls for this facility, as it greatly exceeded Ecology's Q/d threshold of 10.

Ecology states in its draft regional haze plant that the pulp and paper mills are a lower priority than refineries because they "are not located as close to each other as the refineries so they do not have as great of a cumulative effect."[324] Ecology also states that the potential reduction in regional haze emissions from pulp and paper mills is "vastly less than the potential refinery emission reductions."[325] However, the McKinley Paper Company (for which Ecology inexplicably did not conduct a four-factor analysis of controls) has the second highest Q/d value (83.1) of any facility for which Ecology requested four-factor analyses.[326] Three other pulp and paper mills are in the top ten highest Q/d values as calculated by Ecology – the WestRock Tacoma facility, the Nippon Dynawave Packaging Company in Longview, and the Pt Townshend Paper Corporation.[327] While these facilities may not all be located nearby each other, these four facilities along with Cosmo Specialty Fibers, WestRock Longview, and Georgia Pacific Consumer Operations all have Q/d values that are greater than or equal to the Q/d

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[321] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, Appendix O at O1 through O-190 (Reasonably Available Control Technology Analysis for Washington Pulp and Paper Mills, December 2019, Northwest Pulp & Paper Association).
[322] *Id.* At O-282 to O-311 (Cosmo Specialty Fibers Four-Factor Analysis, December 2019).
[323] *Id.* at 162.
[324] WDOE Public Review Draft, Second Regional Haze Plan, October 2021, at 166.
[325] *Id.* at 167.
[326] *Id.* at 161.
[327] *Id.* at 160-161.

threshold of 10 that Ecology set for selecting sources for review. Thus, the decision to defer controls on any of these pulp and paper mills must be based on a four-factor analysis of controls, not a determination that the facilities might not have as great of a cumulative effect on regional haze as the refineries.

### 1. Comments on Ecology's Determination of Cost Effective Controls for the Pulp and Paper Mills

The pulp and paper mill four-factor analyses submitted by NWPPA and by Cosmo Specialty Fibers did not propose to find that any controls were cost effective. Ecology "evaluated and adjusted" these companies' cost information and provided a summary of its revised costs/ton in Appendix J of the draft regional haze SIP. Ecology's adjustments primarily included using a 3.25% interest rate for amortizing capital costs, adjusting the useful life of controls for some sources, and adjusting SNCR NOx control efficiency to 35% for some sources.[328] As will be discussed further below, further adjustments should have been made to the control cost assessments, but even with these changes, Ecology found the following controls would be cost effective based on Ecology's reasonableness cost thresholds. Ecology is assuming a NOx cost reasonableness threshold of $6,300/ton and a PM10 cost reasonableness threshold of $7,800/ton.[329] Ecology must provide justification for its cost reasonableness thresholds. Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton.[330] Colorado is also using a reasonableness cost threshold of $10,000/ton.[331] New Mexico is using a reasonableness cost effectiveness threshold of $7,000/ton.[332]

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[328] *Id.*, Appendix J at J-1 to J-3.
[329] *Id.* at 182-183.
[330] *See* Oregon Regional Haze State Implementation Plan for the Period 2018-2028, Aug. 27, 2021 Public Notice Draft, at 35, 45.
[331] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, available at https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v.
[332] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.

**Table 9. Ecology's Identification of Cost Effective Regional Haze Controls at Pulp and Paper Mills**[333]

| Plant | Emission Unit | Control | Cost Effectiveness, $/ton | RH Pollution Reduced, tons per year |
|---|---|---|---|---|
| Nippon Dynawave | Hog Fuel Boiler #11 | SCR | $5,466/ton | NOx -1,025 tpy |
| Nippon Dynawave | Hog Fuel Boiler #11 | SNCR | $5,413/ton | NOx - 500 tpy |
| Nippon Dynawave | Boiler #9 | SCR | $6,041/ton | NOx - 175 tpy |
| Nippon Dynawave | Boiler #9 | LNB | $2,754/ton | NOx - 97 tpy |
| Packaging Corp. of America (PCA) | Boiler #1 | LNB | $5,893/ton | NOx - 26 tpy |
| PCA | Boiler #2 | LNB | $4,834/ton | NOx - 30 tpy |
| West Rock Longview | Hog Fuel Boiler 20 | SNCR | $6,245/ton | NOx – 115 tpy |
| WestRock Tacoma | Lime Kiln #1 | Wet ESP | $6,964/ton | PM10 – 33 tpy |

All of the above-listed emission units and controls were identified as cost effective controls in Ecology's draft SIP narrative except SNCR at WestRock Longview's Hog Fuel Boiler 20 at a cost effectiveness of $6,245/ton based on a 20-year life (which was provided in the Appendix J "snapshot summary" of Ecology's revised cost calculations of the draft regional haze plan). However, based on Ecology's $6,300/ton NOx cost effectiveness reasonable threshold, SNCR at West Rock Longview's Hog Fuel Boiler 20 should also have been listed as a cost effective control. Assuming, as Ecology has, that SNCR would only reduce NOx emissions by 35%, SNCR at the West Rock Longview Hog Fuel Boiler 20 would reduce NOx by 115 tons per year.[334]

A longer life than the 20-year life Ecology assumed for LNBs, SNCR, and wet ESPs should have been used in its revised cost effectiveness analysis. For example, in its proposed regional haze review for SO2, NOx, and PM controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls (including LNB), SNCR, WESPs, and wet scrubbers in the cost effectiveness evaluation for these controls.[335]

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[333] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, at 183 and Appendix J at J-1.
[334] Based on a 35% NOx reduction from reported 2017 emissions of 328 tons per year, as identified in WDOE, Public Review Draft, Regional Haze Plan for the Second Implementation Period, Appendix O at O-190.
[335] 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).

With respect to SNCR, there is also ample support for assuming a useful life of 25-30 years. While EPA states in the SNCR Control Cost Manual chapter that it is assumed than an SNCR would have a life of 20 years, EPA also states that "[a]s mentioned earlier in this chapter, SNCR control systems began to be installed in Japan the late 1980's. Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993. In responses to another ICR, petroleum refiners estimated SNCR life at between 15 and 25 years."[336] Therefore, based on a 1993 SNCR installation date, these SCNR systems that EPA refers to are at least 28 years old which, all other considerations aside, strongly argues for a 30-year equipment life. Furthermore, an SNCR system is much less complicated than a SCR system, for which EPA clearly indicates the life should be 25 years for industrial units. In an SNCR system, the only parts exposed to the exhaust stream are lances with replaceable nozzles. The injection lances must be regularly checked and serviced, but this can be done relatively quickly, if necessary, is relatively inexpensive, and should be considered a maintenance item. In this regard, the lances are analogous to SCR catalyst, which is not considered when estimating equipment life. All other items, which comprise the vast majority of the SNCR system capital costs, are outside the exhaust stream and should be considered to last the life of the facility or longer. For all of these reasons, Ecology should not have assumed a life of SNCR of any shorter than 25 years, similar to what it assumed for SCR, and a similar lifetime of LNBs should also have been assumed.

In addition, Ecology states that it evaluated SNCR at a removal efficiency of 35% at the Cosmo hog fuel boiler to be consistent with what was assumed for SNCR at the other pulp and paper mills.[337] However, EPA's Control Cost Manual indicates NOx removal efficiencies for SNCR used at boilers in the pulp and paper industry can achieve a median NOx removal efficiency of 50% with urea used as the reagent with a range of 20-62%, and EPA states that the median NOx removal efficiencies with ammonia-based systems at such boilers range from 61-65%.[338] Ecology should not have assumed any lower NOx removal efficiency than 50% with SNCR, assuming use of urea as a reagent. Assuming only 35% NOx removal with SNCR understates the emission reductions achievable with SNCR at boilers used in the pulp and paper industry.

Had Ecology assumed a 25-year life for SNCR and a NOx removal efficiency 50%, it is very likely that SNCR would be cost effective at the West Rock Tacoma Boiler #6, West Rock Tacoma Hog Fuel Boiler 7, PCA's Hog Fuel Boiler, and at the Cosmo Hog Fuel Boiler, based on how close Ecology's SNCR cost effectiveness numbers for these units were to Ecology's $6,300/ton reasonableness threshold. Thus, Ecology should revise the SNCR cost effectiveness

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336 EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-54, available at https://www.epa.gov/sites/default/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf.

337 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, Appendix J at J-1.

338 EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-1 to 1-2, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

analyses for these units to take into account a higher NOx removal efficiency and a longer life of the controls.

With respect to the WestRock Tacoma Hog Fuel Boiler 7, Ecology calculated cost effectiveness of SCR for this boiler at $6,508/ton and SNCR at $6,634/ton which is very close to Ecology's $6,300/ton cost threshold.[339] Ecology stated in its Statement of Basis for the 2011 Air Operating Permit for the facility that the owner of the Tacoma plant requested an increase in the 0.20 lb/MMBtu NOx limit for the boiler and stated that "the 0.20 lb/MMBtu limit was established based on the usage of proper combustion control and previously approved overfire air improvement (OFA) to the power boiler, but the assumptions about the degree of NOx reduction from OFA were wrong."[340] The Statement of Basis further states that the boiler could not meet both the carbon monoxide limit and the NOx limit. The owner of the plant at that time apparently requested a higher NOx limit of 0.30 lb/MMBtu and a higher annual NOx limit of 782 tons per year, which would be a significant increase above the 0.20 lb/MMBtu and 522 ton per 12-month NOx limits that currently apply to the unit.[341] If NOx emissions are going to be allowed to be higher in a subsequent permit action, then both SCR and SNCR would readily be under Ecology's $6,300/ton NOx threshold using Ecology's assumed 20-year life. Further, just changing the SNCR equipment life to 25 years and the interest rate to 3.25% brings the cost effectiveness of SNCR at 35% control at Hog Fuel Boiler 7 to $6,269/ton, which is under Ecology's $6,300/ton cost threshold. For these reasons, Ecology should include the WestRock Tacoma Hog Fuel Boiler 7 in its list of emission units with cost effective NOx controls for at least SNCR. Also, Ecology should disclose the details of the Agreed Order 7688 that was apparently entered into for resolution of the NOx noncompliance issues.[342]

With respect to the Georgia Pacific (GP) Camas plant, Ecology states the plant is "no longer operating as a chemical pulp mill and the emissions will change."[343] According to NWPPA's four-factor report, the GP Camas facility still has some units that are operating , such as the No. 5 Power Boiler and the No. 11 Paper Machine, but it has shut down the Kraft mill, bleach plant, No. 4 Lime Kiln and the No. 4 Recovery Furnace.[344] To the extent that these changes impact Ecology's review of controls for the facility, Ecology must make these changes into enforceable requirements (which could be accomplished by no longer including the units in the facility's operating permit and making clear that any restart of these units would be permitted as new emission units).

Despite Ecology finding that NOx controls at five units and PM10 controls at one unit would be cost effective, Ecology has not proposed any controls for these facilities. Ecology states that "[a]fter we complete the reasonability analysis and determination for the refinery facilities, we

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339 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, Appendix J at J-1.
340 *See* WDOE, Statement of Basis, Air Operating Permit 000085-0, December 12, 2011, at 24, available at https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Industrial-facilities-permits/WestRock-Tacoma.
341 *Id.* at 7-8.
342 *Id.* at 24.
343 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, at 183.
344 *Id.*, Appendix O at page O-14.

plan to conduct a reasonability analysis at pulp and paper facilities. This will be included in a SIP revision or the next implementation period, depending on the timing."[345] Ecology states that it decided that pulp and paper mills are not their first priority for implementation because the pulp and paper mills do not have as much of a cumulative effect on Class I areas as the refineries, because the pulp and paper mills are not in close proximity.[346] Unless the close proximity of the refineries makes regional haze controls more cost effective (for example, if emission units might share pollution controls) or otherwise justifies controls under a four-factor analysis, Ecology's proposed approach is not consistent with the regional haze rules or guidance.

Ecology also lists two other reasons for prioritizing the oil refineries for controls over the pulp and paper mills for controls, including that the potential reduction in regional haze emissions from the pulp and paper mills is much lower than the potential reduction in refinery emissions from controls and that the PCA Wallula mill is generally downwind from the nearest Class I areas.[347] However, the four-factor analysis of the regional haze does not include visibility impacts of a source or source category. For the pulp and paper mills, Ecology is essentially using visibility impacts to reject otherwise cost effective emission controls, by claiming a lower cumulative impact from the pulp and paper industry and/or by claiming the emission reductions (and thus regional haze improvement) won't be as significant as it could be with controls at the refineries. Yet, Ecology decided to evaluate regional haze controls for all sources with a Q/d value greater than or equal to 10. All of the pulp and paper mills evaluated by Ecology have Q/d values that range between 15.6 (West Rock Longview) to 27.9 (WestRock Tacoma),[348] thus the facilities all have Q/d values well over Ecology's threshold level. Further, according to NPCA's analysis, the Nippon Dynawave facility likely affects regional haze in 21 Class I areas, the West Rock Tacoma and West Rock Longview facilities each potentially affect regional haze in 10 Class I areas, and the Port Townshend facility and Cosmo Specialty Fibers facility each likely affect regional haze in 5 Class I areas.[349] Thus, from a regional haze perspective, the decision to evaluate controls for these pulp and paper mills is justified and warranted.

Ecology did not evaluate the other three factors of the four-factor analysis for the sources and emission units for which it found cost effective controls, and thus that analysis is presented here. In terms of energy and non-air environmental impacts, the main issue raised by NWPPA is the cost of power to run the controls,[350] which is taken into account in the cost effectiveness analysis (including for SNCR and SCR) and thus has been addressed. NWPPA stated that all boilers and lime kilns have a remaining useful life of 20 years or more,[351] so the remaining life would not be reason to exclude controls from the regional haze plan. In terms of the time necessary for compliance, NWPPA states that it would take at least four years for compliance if additional

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[345] *Id.* at 184.
[346] *Id.*
[347] *Id.*
[348] *Id.* at 161.
[349] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[350] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period, Appendix O-58 to O-62.
[351] *Id.* at O-63.

controls were ultimately required.[352] NWPPA discusses the need to stagger installation of controls if multiple units at a facility required controls,[353] but that does not need to be considered an impediment to for implementing the controls that Ecology has found to be cost effective for the pulp and paper mills. Ecology has found that SCR is cost effective at Hog Fuel Boiler #11 and at Boiler #9 of the Nippon Dynawave facility,[354] LNB is cost effective at PCA Boilers #1 and #2, and that a wet ESP is cost effective at West Rock Tacoma Lime Kiln #1. In addition, Ecology also should have identified SNCR as cost effective WestRock Longview's Hog Fuel Boiler 20, for which it calculated revised cost effectiveness of $6,245/ton. At the minimum, Ecology should include these emission units control requirements in its regional haze plan for the second implementation period. Ecology should also re-evaluate costs of SNCR to take into account at least a 50% NOx removal efficiency and a 25-year life, which more realistically reflects the useful life of an SNCR system and which reflects the capabilities of an SNCR system at a pulp and paper mill unit. That analysis will likely result in SNCR being cost effective at additional emission units.

In the following sections, more specific comments on the four-factor analyses submitted for each pulp and paper mill are provided.

### 2. *Deficiencies that Appear in All of the NWPPA Pulp and Paper Mill Four-Factor Analyses*

The following provides general comments on the control evaluations and cost-effectiveness analyses that appear to apply to all of the NWPPA four-factor analyses.

NWPPA used an interest rate of 4.8% in amortizing capital costs of most of the controls evaluated.[355] For the evaluation of low NOx burners at the power boilers, NWPPA assumed a much higher interest rate of 7%.[356] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[357] The current bank prime rate is 3.25%.[358] In a cost effectiveness analyses being done today, interest rates in the range of 4.8% to 7% are unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

1. NWPPA assumed too short of a life of pollution controls in amortizing capital costs of controls. For example. NWPPA assumed 20 years for the life of particulate matter (PM) and NOx controls, such as a WESP, improvements to existing ESPSs, and combustion

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[352] *Id.* at O262.
[353] *Id.* at O-62 to O-63.
[354] Ecology also found that SNCR is cost effective at these emission units, but SCR will result in much greater NOx reductions and has a similar cost effectiveness value as SNCR. See Table 9 above.
[355] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-86 to O-116 (Tables B-1 through Table B-31).
[356] *Id.*, Appendix O at O-159 to O-163 (Tables B-57 through Table B-61).
[357] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[358] https://fred.stlouisfed.org/series/DPRIME.

control upgrades. Further, NWPPA only assumed a 15-year life for the SO2 control of the addition of a caustic scrubber at lime kilns and for the addition of a wet scrubber to boilers. NWPPA only assumed a 10-year life for LNBs. ESPs, WESPs, scrubbers, LNBs and other combustion controls should all be considered to have a life of at least 25 years. For example, in its proposed regional haze review for SO2, NOx, and PM controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls, SNCR, WESPs, and wet scrubbers in the cost effectiveness evaluation for these controls.[359] One just needs to evaluate how long existing controls have been in place at some of the emission units at the pulp and paper mills to know that a 25-30 year life (or more) is a much more reasonable assumption than a 15-20 year life. For example, in the Statement of Basis for the WestRock Longview Tacoma Mill, Ecology states as a description of a 2007 permitting action for replacement of a wet scrubber that the "[e]xisting scrubber is 30 years old and nearing end of service life."[360] As another example, Recovery Furnace 22 at the WestRock Longview Tacoma Mill was constructed in approximately 1990 and equipped with an ESP, which was about 30 years ago.[361] In addition, the Georgia Pacific Camas Mill installed an ESP at Power Boiler #3 in 1992, approximately 29 years ago,[362] which is still in operation although NWPPA has indicated that the Camas Mill "does not plan to operate Boiler No. 3 going forward."[363] Thus, there are several examples of pollution controls having useful lives in the range of 25-30 years at pulp and paper mills. It is important for Ecology to require use of a realistic cost of pollution controls in amortizing capital costs of controls because the life of controls assumed has a significant impact on the annualized costs of controls, as does the interest rate.

2. NWPPA appears to use a $3,400/ton threshold to define whether pollution controls were cost-effective.[364] However, no justification has been provided for use of this cost threshold or any cost threshold for defining measures necessary to make reasonable progress, other than that NWPPA cites to the $3,400/ton cost threshold used in the Cross State Air Pollution Rule (CSAPR) for non-electrical generating units.[365] For any cost threshold selected by a state, EPA's regional haze guidance requires that the State Implementation Plan (SIP) "explain why the selected threshold is appropriate for that purpose and consistent with the requirements to make reasonable progress."[366] With respect to determining whether a pollution control is cost effective for a recovery furnace,

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[359] 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).
[360] *See* Washington Department of Ecology, Statement of Basis, Air Operating Permit 0000078, WestRock Longview, LLN, December 15, 2020, at 12, available at https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Industrial-facilities-permits/WestRock-Longview.
[361] *Id.* at 10.
[362] *See* Southwest Clean Air Agency, Title V Basis Statement, SW20-24-R0-A, Georgia-Pacific Consumer Operations LLC, December 17, 2020, at 7, available at https://www.swcleanair.gov/docs/permits/TitleV/SW20-24-R0-ABAS.PDF.
[363] *See* December 2019 NWPPA Report at 1-5.
[364] *Id.* at 2-12 and at 3-16.
[365] *Id.*
[366] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 39.

lime kiln, or power boiler, it is important to consider the costs that similar sources have had to bear to meet Clean Air Act requirements.

The NWPPA Four-Factor Report identifies several examples of pollution controls being installed at the pulp and paper mills evaluated in its report. For example, the burner at the lime kiln at Nippon Dynawave Packaging Company was replaced with a staged combustion natural gas burner in 2017 and the kiln no long fires fuel oil.[367] As another example, an SNCR system was installed at Power Boiler No. 20 of the WestRock Longview Mill in 2012.[368] At the WestRock Tacoma Mill, Power Boiler No. 7 has a spray tower wet scrubber installed on Power Boiler No. 7 in 2017 and low-NOx burners were installed on Power Boiler No. 6 in 2018.[369] The package boiler at Pt Townshend Paper was converted to fire only natural gas using a low-NOx burner in 2016.[370] The hogged fuel boiler at the PCA Wallula Mill had an overfire air system and a WESP installed in 2016.[371] Regardless of the reasons that these controls were installed, the fact that the controls were installed by the companies is indicative of the cost-effectiveness of the controls.

3. NWPPA estimated costs for certain controls based on a report from 2003. Specifically, NWPPA used cost information from the May 1, 2003 report from the National Economic Research Associates (NERA) entitled "Evaluation of Air Pollution Control Costs for the Pulp and Paper Industry."[372] NWPPA used the cost estimates from this report to develop scaled capital cost estimates for WESPs, upgrades to ESPs, and for wet scrubbers.[373] NWPPA escalated costs from the 2003 cost basis of the NERA report to 2018 dollars using the Chemical Engineering Plant Index (CEPCI).[374] However, EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis.[375] EPA states that "[e]scalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate."[376] Further, the cost of an air pollution control does not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

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[367] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-12 to O-13.
[368] *Id.* at O-13.
[369] *Id.*
[370] *Id.*
[371] *Id.* at O-14.
[372] *Id.* at O-164 through O-189.
[373] *Id.*
[374] *Id.*, at O-86 through O-90, O-110 through O-113, O-116 (Appendix B at Tables B-1 through B-5, B-8, B-25 through B-28, and B-31).
[375] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[376] *Id.*

4. NWPPA included costs for sales taxes, property taxes and insurance in its capital costs of controls for several controls evaluated.[377] Yet, in many cases, property taxes do not apply to capital improvements made such as air pollutant controls, and pollution controls are not necessarily considered as increasing risks to necessitate higher insurance costs.[378] In addition, it appears that air pollution controls would be exempt from Washington sales taxes.[379] Ecology must not allow NWPPA to artificially inflate costs by items that likely would not apply to pollution control installations and upgrades.

5. NWPPA somewhat readily dismissed switching/converting to less polluting fuels, stating such fuel switches were too costly without providing sufficient detail for the assumptions of its cost analyses. Specifically, for SO2 control at recovery furnaces, NWPPA stated that the cost of switching to low sulfur No. 2 fuel oil was $12,000/ton based on a 10% capacity factor.[380] It is not clear why the assumption of only a 10% capacity factor is justified for all recovery furnaces that could switch to lower polluting fuels. NWPPA did state that "some recovery furnaces are limited by their air permit to an annual heat input of less than 10% fossil fuel…for avoidance of additional NSPS requirements."[381] However, NWPPA did not identify which of those recovery furnaces had capacity factor limitations, nor did NWPPA explain how those NSPS requirements that the facilities were avoiding with capacity factor limitations might differ if the units utilized a less polluting fuel. Yet, several units have switched from No. 6 fuel oil to No. 2 fuel or from fuel oil to natural gas, as discussed in the NWPPA report in Section 1.2.1 "Summary of Recent Emissions Reductions." Switching to lower sulfur fuel provides the least capital-intensive approach to significantly lowering SO2 emissions, and thus Ecology should not allow such fuel switches to be so readily dismissed as not cost effective without adequate documentation and justification. Indeed, other benefits of switching to less polluting fuels should also be considered in the four-factor analysis. For example, burning of natural gas requires less maintenance than the burning of fuel oil. Thus, Ecology must require that switching to less polluting fuels be more thoroughly evaluated and that any cost effectiveness evaluations be documented with data specific to each furnace or boiler for which this control is evaluated.

In addition to these general concerns that apply to NWPPA's cost effectiveness analyses, the following provides more specific comments to the cost effectiveness evaluations for lime kilns and for power boilers.

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[377] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-86 to O-116 (Appendix B at Table B-1 through B-31).
[378] *See*, e.g., EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80 (Equation 2.69). See also EPA Control Cost Manual, Section 4, Chapter 1 (SNCR), at 1-54.
[379] WAC 458-20-242A.
[380] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-23.
[381] *Id.*

### 3. Comments on SO2 Controls for Lime Kilns

NWPPA states that all lime kiln SO2 emissions are low, "meaning that installing additional SO2 controls would not be cost effective."[382] The emissions presented to make this argument for each facility's lime kilns are from 2017, but NWPPA has not provided any analysis to indicate that operations and SO2 emissions from the lime kilns in 2017 are indicative of typical operating emissions. EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions.[383] Ecology should obtain more information to ensure that these emissions are reflective of typical operations.

EPA stated in a 2014 document that nearly 70% of lime kilns in the pulp and paper industry are equipped with wet scrubbers.[384] Of the lime kilns that NWPPA evaluated, the WestRock Longview Mill Lime Kiln 5 had the highest SO2 emissions in 2017 and is not equipped with a wet scrubber, according to NWPPA's Four-Factor Report. Ecology should evaluate whether this lime kiln's emissions are properly characterized by 2017 data and consider evaluating the addition of a wet scrubber for SO2 control and also PM control.

### 4. Comments on of NOx Controls Evaluations for Power Boilers

NWPPA evaluated NOx controls for several power boilers at the six pulp and paper mills. The controls to be evaluated differed based on the fuel utilized and presumably the boiler type and existing controls. Generally, SNCR and SCR were evaluated for all boilers, and LNB were evaluated for several boilers. The following provides comments on deficiencies noted in NWPPA's NOx cost effectiveness analyses.

1. For SNCR cost evaluations, NWPPA assumed 35% control of NOx, regardless of the NOx inlet rate to the SNCR system.[385] NWPPPA did not provide any justification for that assumption. EPA's Control Cost Manual indicates NOx removal efficiencies for SNCR used at boilers in the pulp and paper industry as achieving a median NOx removal efficiency of 50% with urea used as the reagent with a range of 20-62%.[386] EPA also stated that median NOx reductions with ammonia-based SNCR systems are 61-65% and that most boilers with ammonia-based SNCR systems that are solid fuel-fired are fired

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[382] *Id.* at O-24.
[383] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[384] U.S. EPA, Universal Industrial Sectors Integrated Solutions Model for Pulp and Paper Manufacturing Industry – Universal ISIS-PNP, November 2014, at 2-40, available at https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=311359.
[385] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-43 and O-45.
[386] EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-2, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

with wood or municipal solid waste.[387] Thus, NWPPA has greatly underestimated the NOx reduction capabilities and cost effectiveness of SNCR by only assuming 35% NOx control. Ecology should consider SNCR to achieve at least 50% NOx control at power boilers used in the pulp and paper industry if urea is the reagent.

2. NWPPA used EPA's SNCR cost calculation spreadsheet made available with its Control Cost Manual.[388] For the SNCR control evaluations, NWPPA assumed a 1.5 retrofit factor, which essentially increases capital costs by a factor of 1.5. NWPPA states that "the costs algorithms [of EPA's cost spreadsheet] were developed based on project costs for large coal-fired utility boilers" and assumed, without providing any further justification that EPA's cost algorithms "likely underestimate costs for smaller industrial boilers." Thus, NWPPA applied a retrofit factor of 1.5 "to account for the need to add multiple levels of injectors and perform additional tuning of the system across loads."[389] This was not a justified cost increase. EPA's Control Cost Manual chapter on SNCR costs states there is very little difference in the costs to retrofit SNCR to existing boilers compared to new boilers.[390] EPA's SCNR cost spreadsheet states that it can be used for industrial boilers with maximum heat input capacities of 250 MMBtu/hour or greater and, while EPA has acknowledged that capital costs increase for smaller boilers, the costs do not increase by 50% except for very small boilers.[391] Thus, Ecology should not allow use of any retrofit factor for SNCR costs at any of the power boilers without sufficient documentation from NWPPA or the facility owners to justify the use of a retrofit factor.

3. NWPPA used EPA's SCR cost calculation spreadsheet made available with its Control Cost Manual.[392] EPA's SCR cost spreadsheet already provides a 20% retrofit factor for SCR retrofits as compared to SCR installation costs on a new facility.[393] In addition, the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs, especially due to the large sizes of the SCR reactors and the need for specialized cranes to maneuver large SCR reactors into tight or elevated spaces. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. NWPPA did not provide adequate justification for its application of a 1.5 retrofit factor to SCR cost analyses for power boilers. NWPPA simply said "[a] retrofit factor of 1.5 was applied to all industrial boilers since the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, and the likelihood of needing a

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[387] *Id.* at 1-1.
[388] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[389] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-55.
[390] EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-6.
[391] *Id.* at 1-7 (Figure 1.2).
[392] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[393] This is evident by the fact that if one enters in the Data Inputs tab that the SCR is for a new boiler, the retrofit factor drops from 1 to 0.8.

new ID fan to account for increased pressure drop."[394] Ecology must not allow use of retrofit factors in the SCR cost analyses unless justified based on the specific situation for a particular power boiler.

4. NWPPA did not provide data on the assumptions that went into the cost effectiveness of SCR or SNCR for the power boilers. For example, NWPPA's four-factor submittal does not identify the baseline NOx emissions and emission rates of each boiler in tons per year and lb/MMBtu. It also did not identify the operating hours and/or operating capacity factor of each power boiler used in estimating the operational expenses of these controls. In addition, NWPPA did not identify specific costs assumed for the SNCR and SCR reagent (including what type of reagent was assumed) or the electricity costs. It also is not clear what unit characteristics and fuel characteristics were assumed in the cost spreadsheets for each boiler. Had NWPPA provided a printout of all pages of EPA's SNCR and SCR spreadsheets in its four-factor report, this information could be evaluated. Ecology must ask NWPPA to make all of the pages of the SNCR and SCR spreadsheets available for review for the power boilers.

   It must be noted that the calculated NOx emission reductions for SNCR and SCR seem inconsistent with the baseline emissions assumed for the boilers evaluated for LNB control. Specifically, one can back-calculate the assumed uncontrolled emissions for a boiler by dividing the NOx reductions presented in the spreadsheet printouts for SNCR and SCR by the assumed 35% (for SNCR) and 90% (for SCR) NOx removal efficiency. When we back-calculated those uncontrolled NOx emission rates for the five power boilers that were evaluated for LNB controls (i.e., Nippon Dynawave Boilers 6, 7, and 9 and PCA Wallula Boilers 1 and 2), we found the resulting "uncontrolled NOx emissions" assumed in the SNCR and SCR analyses for these boilers were about 55% higher than the uncontrolled NOx emissions assumed for these units in the LNB cost analyses.[395] Ecology should further evaluate these emission calculations to ensure consistency across all analyses, and to ensure that the baseline NOx emissions truly reflect actual baseline emissions for the power boilers. Having NWPPA submit the entire spreadsheets for these cost calculations would greatly help in ensuring consistency and accuracy of the cost effectiveness calculations.

5. For the analysis of LNBs, NWPPA used a John Zink cost analysis from 2016 for a 99 MMBtu/hr gas-fired boiler.[396] For this analysis, NWPPA inexplicably assumed a 7% interest rate rather than the 4.7% interest rate it assumed for its other cost analyses.[397] As discussed above, there is no justification for such a high interest rate, and Ecology should make sure the current prime rate be used in cost analyses, to be consistent with EPA's

[394] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-57.
[395] *Id.*, Appendix O at O-159 to O-163 (Tables B-57 through Table B-61). The LNB cost analyses for these power boilers identify baseline NOx emissions.
[396] *Id.* at O-57.
[397] *Id.* At O-159 to O-163 (Tables B-57 through Table B-61).

Control Cost Manual. In addition, NWPPA's cost effectiveness analyses of LNB for power boilers assumed LNBs would only have a life of 10 years.[398] Low NOx burners should have a useful life of 25-30 years or more. In evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[399] Thus, NWPPA was not justified in assuming such a short lifetime of LNB and such a high interest rate, and these invalid assumptions improperly made LNB appear to be less cost effective.

It is also questionable whether NWPPA's assumption of only 50% NOx reductions with LNB is a reasonable estimate of achievable emission reductions with LNB. EPA states that NOx emission reductions of 40 to 85% are achievable with low NOx burners.[400] In addition, NWPPA did not evaluate flue gas recirculation (FGR) in combination with LNB. EPA states that these controls are normally used together to reduce NOx, and emission reductions of 60 to 90% are achievable.[401] Indeed, the No. 5 Power Boiler at the Georgia Pacific Camas Mill is equipped with these controls.[402] Ecology must ensure that NWPPA evaluates the most effective combustion controls for the power boilers.

It is important to note that just revising the annualized capital costs of LNBs using NWPPA's cost numbers but using a capital recovery factor reflective of a 3.25% interest rate and a 25-year life makes a significant difference in the cost effectiveness of LNBs at the power boilers, as the table below demonstrates.

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398 *Id.*

399 *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).

400 EPA, AP-42 Emission Factor Documentations, Section 1.4 Natural Gas Combustion, at Section 1.4.4, available at https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.

401 *Id.*

402 WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-48.

**Table 10. Revisions to NWPAA's Cost Effectiveness of LNBs at Power Boilers to Use a Lower Interest Rate and a More Realistic Life of LNB Controls (3.25% Interest Rate, 25-Year Life of LNB)**

| Plant-Unit | Total Annualized Costs (at 3.25% Interest and 25 Year Life) | NOx reductions (per NWPPA), tpy | Revised Cost Effectiveness (at 3.25% Interest Rate and 25-Year Life) | NWPPA's Cost Effectiveness (at 7% Interest Rate and 10-Year Life) |
|---|---|---|---|---|
| Nippon Dynawave Boiler 6 | $141,708 | 18.55 | $7,639 | $12,093 |
| Nippon Dynawave Boiler 7 | $168,795 | 28 | $6,028 | $9,543 |
| Nippon Dynawave Boiler 9 | $250,813 | 97.3 | $2,578 | $4,081 |
| PCA Wallula Boiler 1 | $142,579 | 25.85 | $5,516 | $8,732 |
| PCA Wallula Boiler 2 | $136,856 | 30.3 | $4,517 | $7,162 |

As the Table 10 demonstrates, the use of an unreasonably high interest rate and an unreasonably low useful life of controls can greatly distort the cost effectiveness of controls. Not only do revisions to the cost effectiveness analyses to reflect appropriate interest rates and life of controls improve the cost effectiveness of LNB, but such revisions would also improve the cost effectiveness of SNCR and SCR for the power boilers. Moreover, if more realistic levels of NOx reduction were assumed with LNB and also with SNCR, those controls would likely be more cost effective. Further, as previously stated, no retrofit factor was justified to the SNCR costs or the SCR costs and revising the costs to eliminate the retrofit factor applied would also make those controls more cost effective. Indeed, with these revisions made, it is likely that LNB and/or SNCR would be considered very cost effective for several of the power boilers at the pulp and paper mills. Further, a review of the cost inputs used in the SCR cost analyses is imperative to ensure that costs for items such as reagent, electricity, or catalysts were not overstated in those analyses.

### 5. Comments on Four-Factor Analyses for the Cosmo Specialty Fibers Mill

Cosmo Specialty Fibers (Cosmo) operates a sulfite pulp mill located in Cosmopolis, Washington. A four-factor analysis was submitted for controls at one emissions unit at the plant: the hog fuel boiler at the facility.[403] Cosmo did not provide four-factor analyses for the recovery boilers at the facility (Recovery Boiler 1, 2, and 3), nor did Cosmo provide four-factor analyses for the hogged fuel dryer at the facility.

Cosmo relied on Ecology's 2016 analysis entitled "Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills" dated November 2016 to justify no additional regional haze controls for its recovery boilers.[404] However, the November 2016 Ecology RACT analyses was focused on whether the visibility benefits of pollution controls evaluated justified the costs of the pollution controls. As previously discussed, the visibility benefits of controls are not part of the Clean Air Act's four-factor analysis; thus, Ecology's determination should not add an additional factor to the four statutory factors. It must also be pointed out that Ecology's 2016 RACT analysis was based on emission inventories between 2003 to 2011 and, as noted in the 2016 RACT analysis, Cosmo did not operate from 2007-2010.[405] In fact, a support document for a Title V permit for the Cosmo facility states that when the Cosmo mill restarted in 2011, it had eliminated two processes (cellophane and paper grade production) and only produced dissolving pulp.[406] That basis statement also stated that "[p]roduction varies upon market demand."[407] Thus, Ecology's 2016 report did not have much emissions data reflective of the new operations at the Cosmo facility to base a cost effectiveness analysis of pollution controls on, and a revised analysis of pollution controls must be done for these emission units reflective of current emissions that reflect expected operations in 2028. For these reasons, Ecology's 2016 RACT analysis must not exempt a facility from evaluating pollution controls for any part of its facility.

Cosmo evaluated SCR and SNCR for NOx controls at the hog fuel boiler and evaluated use of an ESP to reduce PM emissions from the hog fuel boiler. Cosmo determined that no additional controls are required at the hog fuel boiler to address regional haze requirements.[408]

*Deficiencies in Cosmo's cost effectiveness analyses*

1. Cosmo assumed a 4.75% interest rate in amortizing capital costs of the controls evaluated.[409] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[410] The current bank prime

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[403] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-278 to O-312 (December 2019 Four-Factor Analysis for Cosmo Specialty Fibers).
[404] *Id.* At O-288.
[405] Washington Department of Ecology, Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills, November 2016, at 34.
[406] Support Document for the Air Operating Permit issued to Cosmo Specialty Fibers, [undated], at 4, available at https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Industrial-facilities-permits/Cosmo-Specialty-Fibers.
[407] *Id.*
[408] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-285.
[409] *Id.* at O-306 to O-308 (Appendix B, Tables 1b, 2b, and 3b).
[410] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

rate is 3.25%.[411] I n a cost effectiveness analyses being done today, an interest rate of 4.75% is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

2. Cosmo assumed too short of a life of pollution controls in amortizing capital costs of controls. Cosmo only assumed a 20-year life in its cost effectiveness evaluations for SCR, SNCR, and ESP.[412] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years.[413] As stated above in the comments on the NWPPA facilities, a simple review of pollution controls at existing boilers and furnaces in the pulp and paper industry shows that pollution controls like ESPs are in place for 25 to 30 years or more. For example, Recovery Furnace 22 at the WestRock Longview Tacoma Mill was constructed in approximately 1990 and equipped with an ESP, which was about 30 years ago.[414] Further, the Georgia Pacific Camas Mill installed an ESP at Power Boiler #3 in 1992, approximately 29 years ago.[415] Thus, a 25-30 year life is likely a more appropriate life of controls to use in amortizing capital costs of a pollution control for the hog fuel boiler. In its proposed regional haze review for SO2, NOx, and PM controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls, SNCR, WESPs and wet scrubbers.[416] It is important for Ecology to use of a realistic life of pollution controls in amortizing capital costs of controls, because the life of controls assumed has a significant impact on the annualized costs of controls, as does the interest rate.

3. In the evaluation of SNCR for NOx control, Cosmo only assumed 25% NOx control would be achieved.[417] Cosmo stated this lower NOx control efficiency was applied due to the "load-swing nature of the Hog Fuel Boiler as well as low NOx concentration…."[418] Ecology should request more information from Cosmo on the load-swing nature of the boiler and how that could impact NOx removal efficiency with SNCR. The hog fuel boiler does appear to run throughout the year, as Cosmo stated the typical operating level of the unit was 357 days per year at 24 hours per day.[419]

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[411] https://fred.stlouisfed.org/series/DPRIME.

[412] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-306 to O-308 (Appendix B, Tables 1b, 2b, and 3b).

[413] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.

[413] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 80.

[414] *Id.* at 10.

[415] *See* Southwest Clean Air Agency, Title V Basis Statement, SW20-24-R0-A, Georgia-Pacific Consumer Operations LLC, December 17, 2020, at 7, available at https://www.swcleanair.gov/docs/permits/TitleV/SW20-24-R0-ABAS.PDF.

[416] 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).

[417] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-295.

[418] *Id.*

[419] *Id.* at O-295 (Table 4-2).

4. In the evaluation of SCR for the hog fuel boiler, Cosmo assumed that the flue gas would need to be reheated and Cosmo took into account estimated costs to reheat the flue gas in the SCR cost effectiveness analysis.[420] The cost for reheating the flue gas reflects 85 to 88% of Cosmo's total annual costs of SCR.[421] Cosmo did not provide the detailed calculations to verify the costs for reheating the flue gas stream, and Ecology must request that data.

5. Cosmo did not evaluate the cost effectiveness of a high dust SCR system which would eliminate any need for flue gas reheating, thus reducing Cosmo's annual cost estimates of SCR significantly. Cosmo's justification for not evaluating a high dust SCR was concerns about particulate emissions poisoning the SCR catalyst.[422] However, there are options to reduce or slow down catalyst deactivation that should have been considered. One study on this issue states that SCR catalyst deactivation in biomass fired plants is mostly due to high potassium content in biomass and that one method to deal with that is potassium removal by adsorption.[423] This paper states that addition of alumino silicates, in the form of coal fly ash, is an "industry proven method of removing [potassium] aerosols from flue gases."[424] Other options to address this concern (aside from tail-end SCR that requires reheating of the flue gas) include the coating SCR monoliths with a protective layer and the use of potassium tolerant SCR catalysts.[425] Ecology must evaluate these other options to accommodate a high dust SCR configuration, which could ultimately end up being a very cost effective and highly effective NOx control.

6. For the ESP evaluated by Cosmo for the hog fuel boiler, Cosmo included costs for property taxes and insurance.[426] Yet, as discussed above, in many cases, property taxes do not apply to capital improvements made such as air pollutant controls, and pollution controls are not necessarily considered as increasing risks to necessitate higher insurance costs.[427] Ecology must not allow NWPPA to artificially inflate costs by items that likely would not apply to pollution control installations and upgrades.

There are examples of similar emission units in the pulp and paper industry in Washington that have installed both NOx and PM controls. For example, the hogged fuel boiler at the PCA

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[420] *Id.* at O-295.
[421] *Id.*
[422] *Id.*
[423] *See* Schill, Leonhard and Rasmus Fehrmann, Strategies of Coping with Deactivation of NH3-SCR Catalysts Due to Biomass Firing, March 30, 2018, available at https://www.mdpi.com/2073-4344/8/4/135/htm and attached as Ex. 12.
[424] *Id.*
[425] *Id.*
[426] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-310 (Appendix B, Table 3a).
[427] *See*, e.g., EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80 (Equation 2.69). *See also* EPA Control Cost Manual, Section 4, Chapter 1 (SNCR), at 1-54.

Wallula Mill had a WESP installed in 2016.[428] In addition, an SNCR was installed at the WestRock Longview Power Boiler 20,[429] which appears to be a similar boiler to the hog fuel boiler at the Cosmo plant, in that the WestRock Longview Power Boiler 20 burns wood fuels (hog fuel, forest biomass, urban wood) and oil (including reprocessed fuel oil), as well as burning paper recycling residuals, primary/secondary sludge from the process wastewater treatment plant, and natural gas.[430] WestRock Power Boiler 20 is described as a "hybrid suspension grate boiler designed to fire wet biomass…."[431] Ecology should further evaluate the SNCR installed at the WestRock Longview Power Boiler 20 to determine the percent NOx removal being achieved at that unit to assess SNCR NOx removal capabilities for the hog fuel boiler at the Cosmo facility. Because a similar source has found it cost effective to install SNCR to reduce NOx emissions, that provides a strong basis to consider SNCR as a cost-effective control for the Cosmo hog fuel boiler. Note that the Title V statement of basis for the WestRock Longview plant indicates that the SNCR was installed at the WestRock Longview Power Boiler 20 to reduce NOx emissions as part of Order 8429 which allowed for higher solid fuel firing rate.[432] Thus, the SNCR was likely installed to allow the increased solid fuel firing rate at WestRock Longview Boiler 20 to "net out" of major source permitting requirements. Controls installed to net out of major source permitting requirements should be considered controls required under the Clean Air Act. Such controls provide a relevant example of a source determining it was cost-effective to install the pollution control, even if the reasoning was to avoid a more substantive Clean Air Act requirement.

## IV. Additional Facility that Ecology Should Evaluate for Regional Haze Controls

One additional facility that Ecology should evaluate for regional haze controls is the Ardagh Glass plant in Seattle, Washington. According to NPCA analysis, the Ardagh Glass facility potentially affects regional haze in 2 Class I areas.[433] NPCA previously submitted to Ecology a four-factor analysis of regional haze controls for the Ardagh Glass Plant with its February 16, 2021 comment letter to Ecology for the informal comment period,[434] but Ecology has not responded to those comments in the public review draft regional haze plan for the second implementation period.

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[428] WDOE, Public Review Draft, Washington Regional Haze Plan for the Second Implementation Period Appendix O at O-14.
[429] *Id.*
[430] Washington Department of Ecology, Statement of Basis for Air Operating Permit 0000078, WestRock Longview, December 15, 2020, at 42, available at https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Industrial-facilities-permits/WestRock-Longview.
[431] *Id.*
[432] *Id.* at 43.
[433] NPCA, Clear Solutions for Parks, Regional Haze Fact Sheet, Washington, available at https://drive.google.com/file/d/1TKDIvvNwQ6LnVlVjzq4FYoQIOOlPyFmp/view.
[434] *See* NPCA, Comments Submitted for Informal comment period: Regional Haze SIP Revision - 2nd 10-Year Plan, February 16, 2021, at 11.

Ecology's air emissions inventory for the Ardagh Glass Plant identifies the following emissions for 2014-2019 at the plant.

**Table 11. Ardagh Glass Plant Emissions, 2014 to 2019**[435]

| Year | NOx, tpy | SO2, tpy | PM10, tpy |
|---|---|---|---|
| 2014 | 172.1 | 105.9 | 73.2 |
| 2015 | Not reported | Not Reported | Not Reported |
| 2016 | 153.7 | 98.7 | 95.3 |
| 2017 | 153.3 | 98.7 | 88.2 |
| 2018 | 167.6 | 89.9 | 82.2 |
| 2019 | 172.7 | 56.7 | 66.5 |

The largest sources of emissions at a glass plant are the fossil fuel-fired furnaces which melt glass. At the Ardagh plant, there are five furnaces. No. 1 is an all-electric furnace; No. 2, No. 3 and No. 5 furnaces are oxy-fuel fired; and No. 4 is an end-port regenerative furnace. The Furnace No. 1 does not have reported emissions. Furnaces Nos. 2, 3 and 5 are oxy-fuel fired. This combustion technique should reduce the formation of NOx. Furnace No. 5 is equipped with a Tri-Mer Cloud Mist Scrubber, which should capture the SO2 and PM emissions.

At the request of NPCA, Steve Klafka of Wingra Engineering, evaluated the use of ceramic catalytic filtration systems at Furnaces 2, 3, 4, and 5 of the Ardagh Glass Plant.[436] This is the same pollutant control technology discussed in Section II.C. above for the Ash Grove Cement Plant. The Klafka Report discusses how ceramic catalytic filtration systems have been used at existing glass plants as a highly effective multi-pollutant control technology.[437] The Klafka Report included a cost analysis for ceramic catalytic filtration systems at the Ardagh Glass Plant furnaces to reduce NOx and also SO2 and PM10. Table 12 below summarizes the results of his analysis.

[435] Data from Ecology's Point Source Emissions Inventory available at https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Air-emissions-inventory.
[436] *See* January 27, 2021 Four-Factor Reasonable Progress Analysis for the Ardagh Glass plant in Seattle, Washington, done by Wingra Engineering, S.C., attached as Ex. 9.
[437] *Id.* at 9.

**Table 12 - Cost Effectiveness for a Catalytic Ceramic Filter System to Control Actual and Potential Emissions from the Ardagh Glass Plant Furnaces[438]**

| Basis | Based on 2014 Actual Emissions | Based on Potential Emissions |
|---|---|---|
| Capital Costs | \$11,866,967 | \$16,468,204 |
| Annual Operating Costs | \$330,980 | \$700,622 |
| Annual Capital and Operating Costs | \$1,451,222 | \$2,255,220 |
| NOx Removed (tpy) | 155 | 618 |
| SO2 Removed (tpy) | 79 | 217 |
| PM Removed (tpy) | 70 | 173 |
| Total NOx, SO2 and PM Removed (tpy) | 304 | 1,008 |
| Cost Effectiveness (\$ per Total Tons Removed) | \$4,766 | \$2,238 |

The Klafka Report indicated that it would take twelve months to construct and install a ceramic catalytic filtration system at Ardagh Glass.[439] The Klafka Report did not identify issues with energy or non-air environmental impacts of the control because the cost analysis took into account the costs of electricity, assumed use of aqueous ammonia, and the cost for 100% of the dust due to the use of hydrated lime for SO2 control.[440] The Klafka report did discuss how glass furnaces need to be rebuilt every 10-20 years, but it did not find such a rebuilding of the furnace would limit the remaining useful life of the glass plant because it has been in that location since 1931.[441] The Klafka Report concluded that it is technically feasible to add a catalytic ceramic filtration system to the glass furnaces at Ardagh Glass and that it would be very cost effective to do so, at a cost per total tons of pollutant removed of \$4,766/ton based on emission reductions from 2014 actual emissions and at a cost of \$2,238/ton based on emission reductions from potential emissions.[442]

Thus, a ceramic catalytic filtration system is a very cost effective control that can significantly reduce emissions from the Ardagh Glass Plant, and Ecology should strongly consider this control at Ardagh Glass as part of its regional haze control strategy.

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438 *Id.* at 11.
439 *Id.* at 10.
440 *Id*. at 11.
441 *Id.* at 11-12.
442 *Id.* at 12. Note that the narrative discussion of the Klafka report indicates lower cost effectiveness numbers of \$3,768/ton for reductions from 2014 emissions and \$1,819/ton from reductions in potential emissions, but Table 5 of the report indicates a higher cost per ton of pollutants removed. The Table 5 data of the Klafka Report is included in Table 12 of this report as the data are assumed to be the more accurate numbers.

**Wingra Engineering, S.C.**
*Environmental Engineering Consultants*

January 27, 2021

National Parks Conservation Association
Clean Air and Climate Program
Attn: Stephanie Kodish, Senior Director & Counsel
777 6th Street NW, Suite 700
Washington, DC 20001-3723

Subject: Four-Factor Reasonable Progress Analysis
Ardagh Glass, Inc.
Seattle, Washington

Dear Ms. Kodish:

The National Parks Conservation Association requested the preparation of a Four-Factor Reasonable Progress Analysis for Ardagh Glass, Inc. in Seattle, Washington. This analysis evaluates the feasibility of installing emission control equipment for air pollutants which are precursors to regional haze. The enclosed report describes the procedures and results of this analysis.

Should you have further questions, please contact me at (608) 255-5030.

Sincerely,

**Wingra Engineering, S.C.**

Steven Klafka

Steven Klafka, P.E., BCEE
Environmental Engineer

Enclosure

# Ardagh Glass, Inc.

## Seattle, Washington

# Four-Factor Reasonable Progress Analysis

## January 27, 2021


*Prepared by:*

*Steven Klafka, P.E., BCEE*

*Wingra Engineering, S.C.*

*Madison, Wisconsin*

## 1.0 INTRODUCTION

In 2010, Washington Department of Ecology (DOE/WDOE) updated its regional haze state implement plan to improve visibility in certain national parks and wilderness areas in the state.[1] These are referred to as Class I areas for implementation of air pollution protection regulations and include the following:

- Alpine Lakes Wilderness
- Glacier Peak Wilderness
- Goat Rocks Wilderness
- Mt. Adams Wilderness
- Mt. Rainier National Park
- North Cascades National Park
- Olympic National Park
- Pasayten Wilderness

Figure 1 is a WDOE map showing the location of these areas.[2]

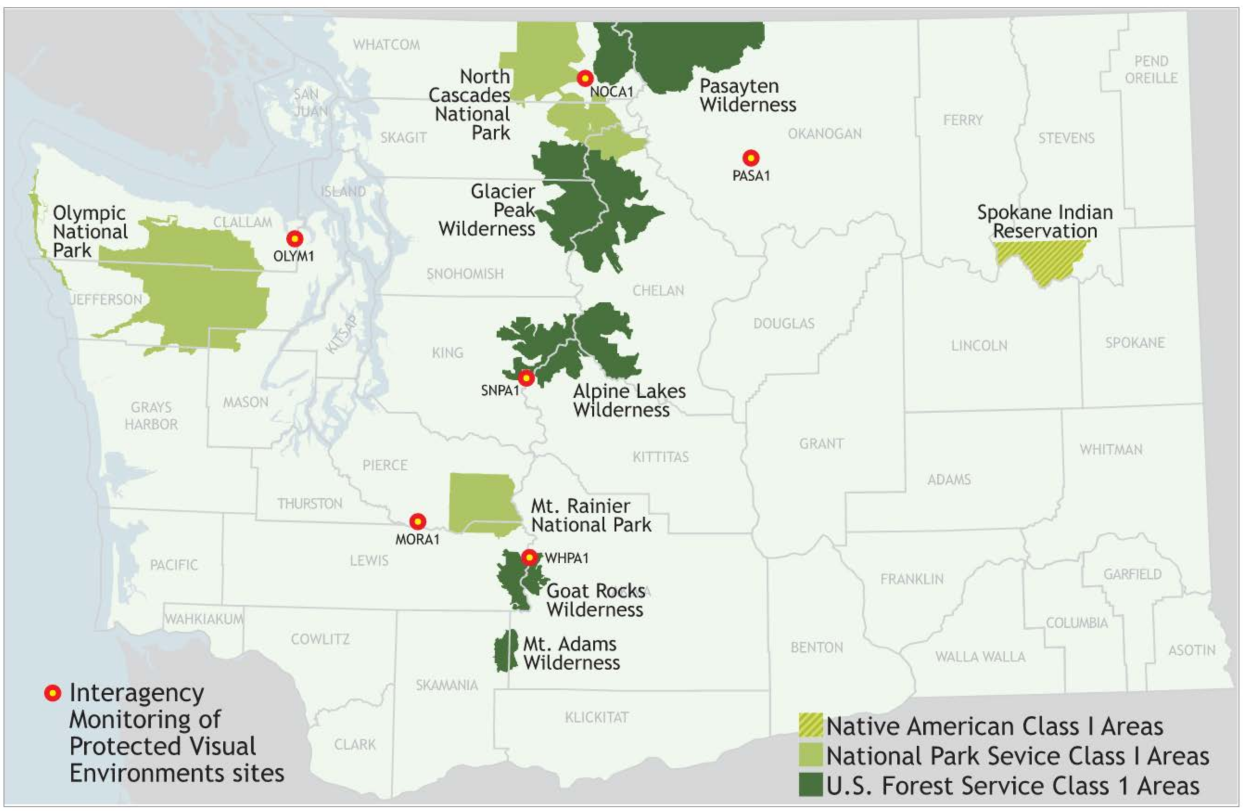


**Figure 1 - Washington State Class I Areas**

[1] Department of Ecology, State of Washington, Regional Haze, State Implementation Plan, Final December 2010
[2] https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze

The DOE regional haze state implementation plan is evaluating the retrofit of emission control technology at large industrial sources to make reasonable progress toward natural conditions in Class 1 areas. To determine the effectiveness of retrofitting emissions control technology, USEPA requires states to use a Four-Factor Reasonable Progress Analysis (FFA). In its background document for this analysis, WDOE states:

*Consider 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 sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal (40 CFR 51.308(d)(1)(i)(A)). This four factor analysis is used to identify controls necessary to meet the reasonable progress goals for each mandatory Class 1 area (CIA).*

Therefore, the four statutory factors are:

- Costs of compliance
- Time necessary for compliance
- Energy and non-air quality impacts of compliance
- Remaining useful life of any potentially affected sources

This report presents an FFA for Ardagh Glass, Inc. located in Seattle, Washington. DOE has identified this industrial facility has potentially having impacts on regional haze at surrounding Class I areas.

## 2.0 FACILITY DESCRIPTION

Ardagh Glass, Inc. is located at 5801 East Marginal Way S. in Seattle, King County, Washington. It manufactures glass containers. It was issued Air Operating Permit No. 11656 on June 6, 2007. Specifications for the air pollution sources at the plant are taken from this operating permit and the Statement of Basis for Administrative Amendment 5-31-17 (SOB) which provides a description of activities and a compliance history for the plant. Both documents were obtained from the Puget Sound Clean Air Agency.[3]

The closest Class I areas to Ardagh include the following:

- Olympic National Park
- Alpine Lakes Wilderness
- Mount Rainier National Park
- Glacier Peak Wilderness
- Goat Rocks Wilderness

[3] https://www.pscleanair.gov/182/List-of-Approved-Permits

In its regional haze plan, DOE modeled facilities that were within 300 km of Class I areas to determine if they had a significant impact these areas. The closest Class I area to Ardagh is the Alpine Lakes Wilderness at 53.5 km. All of the Class I areas are within the 300 km distance from Ardagh.

While there are numerous air pollution sources at glass manufacturing plants, the largest sources are the fossil fuel-fired furnaces which melt glass. At the Ardagh plant, there are five furnaces. No. 1 is an all-electric furnace; No. 2, No. 3 and No. 5 furnaces are oxy-fuel fired; and, No. 4 is an end-port regenerative furnace.

For the No. 1 glass furnace, DOE states that the company does not have any reported emissions from this electric furnace and it vents through the roof and normally has no visible emissions, but is capable of emitting visible emissions from the furnace during upset conditions. It will be assumed for this analysis that there are no significant emissions from this furnace and its emissions will not be considered.

Specifications for the remaining furnaces are provided in Table 1. The actual daily production melt rates are taken from the Puget Sound Clean Air Agency SOB and come from 1994 source tests. Current emission inventory reports only provide annual production rates. If 1994 are the last source tests, it is recommended that DOE require new stack tests to verify current actual emission rates.

The full production capacity of each furnace provided by the SOB is also summarized in Table 1.

***Table 1 - Ardagh Glass Furnace Specifications***

| Glass Melting Furnace | Tested Melt Rate | Capacity Melt Rate |
|---|---|---|
| | (tons per day) | (tons per day) |
| No. 2 | 144.6 | 195 |
| No. 3 | 166.8 | 160 |
| No. 4 | 131.3 | 430 |
| No. 5 | 130.7 | 205 |
| Total | 573.4 | 990 |

Table 2 provides the annual actual emissions from the Ardagh plant as reported in its emissions inventory submitted to DOE.[4] The air pollutants evaluated include nitrogen oxides ($NO_x$), sulfur dioxide ($SO_2$) and particulate matter (PM). The actual emissions can be used to estimate the cost effectiveness of emission control equipment in an FFA.

[4] Department of Ecology, State of Washington, Air emissions inventory summaries, https://ecology.wa.gov/Air-limate/Air-quality/Air-quality-targets/Air-emissions-inventory

Furnaces Nos. 2, 3 and 5 are oxy-fuel fired. This combustion technique would reduce the formation of $NO_x$. It is assumed that any $NO_x$ emission reductions due to this technique are already incorporated into the reported actual emissions summarized in Table 2. The DOE SOB indicates Furnace No. 5 was equipped with a Tri-Mer Cloud Mist Scrubber in approximately 2009. This scrubber would capture the $SO_2$ and PM emissions. It is assumed that the reported actual emissions incorporate any emission reductions due to the use of the mist scrubber.

***Table 2 - Ardagh Actual Emissions***

| Reporting | $NO_x$ | $SO_2$ | $PM_{10}$ | Total |
|---|---|---|---|---|
| 2012 | 227.1 | 61.4 | 75.2 | 363.7 |
| 2013 | 166.5 | 73.3 | 92.8 | 332.6 |
| 2014 | 172.1 | 105.9 | 73.2 | 351.2 |
| 2016 | 153.7 | 98.7 | 95.3 | 347.6 |
| 2017 | 153.3 | 98.7 | 88.2 | 340.2 |
| 2018 | 167.6 | 89.9 | 82.2 | 339.7 |
| Maximum | - | - | - | 351.2 |

Table 3 provides the annual potential, legally enforceable emissions from the Ardagh plant. It is a common practice in air pollution control, especially for a Best Available Control Technology analysis following the federal Prevention of Significant Deterioration regulations, to estimate the cost effectiveness of air pollution control equipment based on 100% capacity and the potential emissions. As shown in Table 2, actual annual emissions vary with annual production. Looking at historical emission inventory reports, total emissions have been as high as 700.7 tpy in 2008. Based on the Ardagh air quality operating permit, there is no limitation on annual production. Actual emissions are approved as long as they remain below the potential emissions approved by the operating permit. Potential emissions, in addition to actual emissions, can be used to estimate the cost effectiveness of emission control equipment in an FFA.

*Table 3 - Ardagh Potential Emissions*

| Glass Melting Furnace | Capacity (tons per day) | Air Pollutant | Limitation (lbs/ton) | Limitation (tpy) |
|---|---|---|---|---|
| No. 2 | 195 | $NO_x$ | 3.8 | 135 |
| | | $SO_2$ | 1.6 | 57 |
| | | PM | 1.0 | 36 |
| No. 3 | 160 | $NO_x$ | 3.8 | 111 |
| | | $SO_2$ | 1.6 | 47 |
| | | PM | 1.0 | 29 |
| No. 4 | 430 | $NO_x$ | 3.8 | 298 |
| | | $SO_2$ | 1.6 | 126 |
| | | PM | 1.0 | 78 |
| No. 5 | 205 | $NO_x$ | 3.8 | 142 |
| | | $SO_2$ | 1.6 | 60 |
| | | PM | 1.0 | 37 |
| Total | 990 | $NO_x$ | - | 687 |
| | | $SO_2$ | - | 289 |
| | | PM | - | 181 |
| | | All | - | 1,156 |

## 3.0 FOUR-FACTOR ANALYSIS

The four factors included in this analysis are:

- Costs of compliance
- Time necessary for compliance
- Energy and non-air quality impacts of compliance
- Remaining useful life of any potentially affected sources

Each of these factors are evaluated for the Ardagh plant.

### 3.1 Costs of Compliance

The emissions from the Ardagh furnaces which need to be controlled are $NO_x$, $SO_2$ and PM. Historically, these pollutants were controlled using separate air pollution control systems due to their physical and chemical properties. $NO_x$ emission control requires changes in the combustion conditions that form $NO_x$ from $N_2$ at high temperatures, or use ammonia or urea injection to react with the $NO_x$ to form $N_2$ as the reaction product. $SO_2$ emissions require wet or dry injection of a chemical to react with and neutralize this pollutant. PM emissions are solids which requires capture by filtering or agglomeration into larger particles using water sprays.

Furnace No. 1 at the Ardagh plant is electrically heated. Puget Sound concluded there were no emissions from this furnace except during upsets. If this is true, then changing the other four furnaces from fossil fuel-fired to electrically heated is an emission control option that DOE should evaluate. Glass furnaces are rebuilt every 10 to 20 years. The next rebuilt would be an appropriate time to change the heating method.

A common resource to determine the latest control methods for an industry is the *BACT Clearinghouse* operating by the United States Environmental Protection Agency (USEPA).[5] This website lists the most recent results of Best Available Control Technology analyses for air pollution permits issued to major source under the Prevention of Significant Determination. For glass manufacturing, the website provides only two entries during the past 10 years. These include the 700 ton per day flat glass plant approved for Cardinal FG Company in Winlock, Washington. As BACT, the glass furnace was equipped with a spray drier scrubber for $SO_2$ control, ESP to capture PM, and use of the *3R Process* combustion modifications to reduce $NO_x$ emissions. The second project was 18 furnaces for the production of high purity glass at the Corning Incorporated plant in Canton, New York. BACT for $NO_x$ emissions was determined to be the use of oxygen-fired combustion to minimize the formation of $NO_x$.

There have been additional emission control projects in the U.S. which have not been subject to the PSD regulations so are not documented in the BACT Clearinghouse. These also provide insight into demonstrated emission control methods.

In 2010, USEPA reached a settlement with Saint Gobain Containers Inc. over violations of the Clean Air Act at their container glass plants.[6] The settlement required the installation of new emission control systems for $NO_x$ including the use of an Oxyfuel Furnace, Oxygen Enriched Air Staging (OEAS) and Selective Catalytic Reduction (SCR); new emission control systems for $SO_2$ including semi-dry scrubbers, dry scrubbers, cloud chamber scrubber systems and process controls; and, new emission control systems for PM including cloud chamber scrubber systems, electrostatic precipitators, or process controls. Ardagh Glass Inc. later purchased some of the Saint Gobain plants included in the USEPA settlement. These plants included the Seattle facility. In the settlement, this plant was required to use oxyfuel to reduce $NO_x$ emissions from Furnaces No. 3 and 5 and install a cloud chamber scrubber system to reduce $SO_2$ and PM emissions from Furnace No. 5.

In 2015, USEPA reached a settlement with Guardian Industries Corporation over violations of the Clean Air Act at their flat glass plants.[7] Guardian was required to install new emission controls for $NO_x$, $SO_2$ and PM including selective catalytic reduction, dry scrubbing and dust capture

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[5] https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information
[6] https://www.epa.gov/enforcement/saint-gobain-containers-inc-clean-air-act-settlement
[7] https://www.epa.gov/enforcement/guardian-industries-corp-clean-air-act-settlement

equipment. For some plants, Guardian chose to use a new emission control technology which has been demonstrated to simultaneously control $NO_x$, $SO_2$ and PM emissions from glass plants. This technology uses catalytic ceramic filters in combination with ammonia injection for $NO_x$ control and reagent injection for $SO_2$ control. PM is captured on the surface of the ceramic filters.

In 2015, Cardinal FG Company began a voluntarily program to install additional control equipment to reduce it flat glass plant emissions. At three existing flat glass plants already equipped with spray drier – ESP control systems for $SO_2$ and PM control, an additional Selective Catalytic Reduction or SCR system for $NO_x$ control would be installed. At two existing flat glass plants using the *3R Process* for $NO_x$ control, the new catalytic ceramic filter control system has been installed. Compliance testing of catalytic ceramic filter systems show they are achieving the lowest emission levels for $NO_x$, $SO_2$ and PM combined at existing glass plants. Based on the system quotation used for this analysis, the guaranteed control efficiencies for these air pollutants are 90%, 75% and 95.8%, respectively.

The two catalytic ceramic filter installations at Cardinal FG were manufactured by the Tri-Mer Corporation. Table 4 summarizes glass plant installations of the catalytic ceramic control system by Tri-Mer. It is noteworthy that one of the installations is the Ardagh Glass container plant in Dolton, Illinois. This makes this type of system an excellent option to consider for controlling the emission of these pollutants from the Ardagh plant in Seattle. Based on the success of the catalytic ceramic filter systems at existing glass plants, it will be used for the FFA for the Ardagh plant in Seattle.

***Table 4 - Tri-Mer Filter Projects in U.S.***

| Company | Location | Glass Type |
|---|---|---|
| Durand | Millville, NJ | Tableware |
| Anchor | Monaca, PA | Mixed |
| AGC | Church Hill, TN | Flat |
| Gallo | Modesto, CA | Container |
| AGC | Hill, KS | Flat |
| Adagh | Dolton, IL | Container |
| Kohler | Kohler, WI | Specialty |
| Guardian | Carleton, MI | Flat |
| PG Corporation | L.A. Basin | Specialty |
| Cardinal FG | Mooresville, NC | Flat |
| Cardinal FG | Durant, OK | Flat |

For typical BACT analyses, order-of-magnitude cost estimates are typically generated.[8] The cost estimate is improved if it incorporates actual vendor quotations for the required equipment. A prior quotation for a catalytic ceramic filter system was available for one of the Cardinal FG plants. Like the Ardagh plant, the cost estimate reflects the retrofit of a new control system at an existing

[8] USEPA, Air Pollution Control Manual, Sixth Edition, EPA/452/B-02-001 January 2002.

industrial facility. These capital, installation and operating costs were adjusted to reflect the differences between the Cardinal and Ardagh plants. The development of this cost estimate is provided in the supporting calculations of Appendix A.

As previously noted, BACT analyses are typically based on full capacity and potential emissions. For Ardagh, cost estimates were developed for both actual and potential production and emissions. The actual cost estimate is based on reported emissions and incorporates any existing air pollution control measures on the four glass furnaces at Ardagh. The potential cost estimate reflects the production capacity and emissions approved for the four glass furnaces.

Table 5 presents a summary of the cost estimate for the Ardagh plant. Because the catalytic ceramic filter system is a multi-pollutant control technology, cost effectiveness was calculated based on the total expected emission reductions in $NO_x$, $SO_2$, and PM emissions. The cost effectiveness for actual conditions is $4,766 per ton of total air pollutants removed and for potential conditions is $2,238 per ton of total air pollutants removed. Both of these values are well within the cost effectiveness level considered reasonable in prior BACT and control equipment analyses by regulatory agencies. It is not unusual for $10,000 per ton of pollutant removed to be considered acceptable. In correspondence with DOE staff on this topic, they provided reasonable cost example values for actual and potential emissions of $5,250 and 4,000 per ton, respectively.[9] The estimates for Ardagh are within these values. It is concluded that the installation of a catalytic ceramic filter system at the Ardagh plant in Seattle would be considered a reasonable expense.

This analysis is more accurate than one based on order-of-magnitude cost estimates. However, it would be improved if a budget quotation were obtained for the plant.

## 3.2 Time necessary for compliance

Based on prior projects, the time frame to obtain a quotation for a catalytic ceramic filter, issue a purchase order, complete engineering, construct and install the equipment is 12 months. Furnace No. 5 at the Seattle plant is equipped with a Cloud Mist Scrubber manufactured by Tri-Mer. Additionally, the plant in Dolton, Illinois is equipped with a catalytic ceramic filter system manufactured by Tri-Mer. The familiarity of Ardagh staff with Tri-Mer products would improve the ability to obtain a quotation and installation of a new control system at the Seattle plant.

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[9] Email, P. Gent – WDOE to S. Klafka – Wingra Engineering, Regional haze four-factor analysis for Ardagh Glass, Inc., January 19, 2021.

***Table 5 - Cost Estimate for Catalytic Ceramic Filter System to Control Actual and Potential Emissions from Ardagh Glass, Inc.***

| Basis | Actual | Potential |
|---|---|---|
| Capacity (tpd) | 573.4 | 990 |
| Capital Costs | $11,866,967 | $16,468,204 |
| Annual Capital Costs | $816,210 | $1,132,683 |
| Annual Operating Costs | $330,980 | $700,622 |
| Annual Capital and Operating Costs | $1,147,190 | $1,833,305 |
| Inlet $NO_x$ (tpy) | 172 | 687 |
| Inlet $SO_2$ (tpy) | 106 | 289 |
| Inlet PM (tpy) | 73 | 181 |
| Inlet Total $NO_x$, $SO_2$ and PM (tpy) | 351 | 1,156 |
| Outlet $NO_x$ (tpy) | 17 | 69 |
| Outlet $SO_2$ (tpy) | 26 | 72 |
| Outlet PM (tpy) | 3 | 8 |
| Outlet Total $NO_x$, $SO_2$ and PM (tpy) | 47 | 148 |
| Removed $NO_x$ (tpy) | 155 | 618 |
| Removed $SO_2$ (tpy) | 79 | 217 |
| Removed PM (tpy) | 70 | 173 |
| Removed Total $NO_x$, $SO_2$ and PM (tpy) | 304 | 1,008 |
| Cost Effectiveness ($ per Total Ton removed) | $3,768 | $1,819 |

### 3.3 Energy and non-air quality impacts of compliance

Significant operating costs in order of magnitude include electricity, ammonia reagent, hydrated lime reagent and labor. These costs are taken into account in the enclosed cost estimates. The cost estimates provided in this report incorporate electricity usage for control system fans.

The cost estimates adjust ammonia reagent consumption rates based on the anticipated actual and potential emissions. The ammonia selected for the control of $NO_x$ emissions is 19% aqueous ammonia. This is a less concentrated and safer alternative to anhydrous ammonia. This type of ammonia has no federal requirement to evaluate the potential impacts of an accidental release.

The cost estimates adjust hydrated lime consumption rates based on the anticipated actual and potential emissions. The calcium sulfate formed by the reaction of hydrated lime with $SO_2$ will be captured as dust by the ceramic filters. Calcium sulfate is a raw material in glass making and it is common practice to recycle the captured dust to the glass furnace. The cost estimates provided with this report includes the cost of a recycling system for 100% of the dust. This system avoids waste disposal impacts and costs.

### 3.4 Remaining useful life of any potentially affected sources

It is common practice in the glass industry to rebuild glass furnaces after their refractory has completed its useful life. This may last 10 to 20 years. It is not clear from the available DOE background documents how long a glass factory has been in the location of Ardagh. A history of glass container manufacturing suggests there has been a Ardagh connected plant in Seattle since 1931.[10] This would suggest there have been numerous new and rebuilt furnaces, and a new control system at the Ardagh plant would continue to operate for its entire useful life. As previously discussed with available emission control options, the time when a glass furnace is rebuilt would be an appropriate time to consider changing from a fossil fuel-fired furnace to one that is electrically heated and eliminating the emissions associated with regional haze.

## 4.0 CONCLUSIONS

It is technically feasible to add additional emission controls to the Ardagh Glass Inc. plant in Seattle and further reduce its air pollution emissions of $NO_x$, $SO_2$ and PM which contribute to regional haze. The catalytic ceramic control system evaluated in the enclosed FFA has been installed on other glass plants, including Ardagh's own plant in Illinois.

The existing Seattle plant does have some control measures in place. Furnace Nos. 2, 3 and 5 are oxy-fuel fired to reduce their $NO_x$ emissions and Furnace Nos. 3 and 5 are equipped with a cloud mist control system to reduce $SO_2$ and PM emissions. Nevertheless, the residual emissions can be controlled further by the use of the catalytic ceramic control system.

Based on actual and potential emissions, the enclosed cost estimates show that the new control system would have a cost effectiveness of $3,768 and $1,819 per ton of total air pollutants removed, respectively. Both of these values represent a reasonable expenditure for the reduction of $NO_x$, $SO_2$ and PM emissions.

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[10] https://glassbottlemarks.com/ball-bros-glass-company/

# Appendix A

# Supporting Cost Calculations

| | Reference | Original | Reference | Original | Reference | Ardagh | Reference | Ardagh |
|---|---|---|---|---|---|---|---|---|
| Basis | | Potential | | Potential | | Actual | | Potential |
| Capacity (tpd) | Quotation | 700 | | 700 | 2017 DOE SOB | 573.4 | 2017 DOE SOB | 990 |
| Inlet NOx (lbs/ton) | Quotation | 18.0 | | 18.0 | | | 2017 DOE SOB | 3.8 |
| Inlet SO2 (lbs/ton) | Quotation | 4.0 | | 4.0 | | | 2017 DOE SOB | 1.6 |
| Inlet PM (lbs/ton) | Quotation | 1.2 | | 1.2 | | | 2017 DOE SOB | 1 |
| Inlet NOx (tpy) | Calculated | 2,299.5 | | 2,299.5 | 2014 Inventory | 172.1 | Calculated | 686.6 |
| Inlet SO2 (tpy) | Calculated | 511.0 | | 511.0 | 2014 Inventory | 105.9 | Calculated | 289.1 |
| Inlet PM (tpy) | Calculated | 153.3 | | 153.3 | 2014 Inventory | 73.2 | Calculated | 180.7 |
| NOx Removal (%) | IN vs OUT | 90.0% | | 90.0% | Same as Original | 90.0% | Same as Original | 90.0% |
| SO2 Removal (%) | IN vs OUT | 75.0% | | 75.0% | Same as Original | 75.0% | Same as Original | 75.0% |
| PM Removal (%) | IN vs OUT | 95.8% | | 95.8% | Same as Original | 95.8% | Same as Original | 95.8% |
| Outlet NOx (lbs/ton) | Quotation | 1.8 | | 1.8 | | | Calculated | 0.38 |
| Outlet SO2 (lbs/ton) | Quotation | 1.0 | | 1.0 | | | Calculated | 0.40 |
| Outlet PM (lbs/ton) | Quotation | 0.1 | | 0.1 | | | Calculated | 0.04 |
| Outlet NOx (tpy) | Calculated | 230.0 | | 230.0 | Calculated | 17.2 | Calculated | 68.7 |
| Outlet SO2 (tpy) | Calculated | 127.8 | | 127.8 | Calculated | 26.5 | Calculated | 72.3 |
| Outlet PM (tpy) | Calculated | 6.4 | | 6.4 | Calculated | 3.1 | Calculated | 7.5 |
| Removed NOx (tpy) | Calculated | 2,069.6 | | 2,069.6 | Calculated | 154.9 | Calculated | 617.9 |
| Removed SO2 (tpy) | Calculated | 383.3 | | 383.3 | Calculated | 79.4 | Calculated | 216.8 |
| Removed PM (tpy) | Calculated | 146.9 | | 146.9 | Calculated | 70.2 | Calculated | 173.1 |
| Removed NOx, SO2 and PM (tpy) | Calculated | 2,599.7 | | 2,599.7 | Calculated | 304.5 | Calculated | 1,007.9 |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| **Capital Costs** | | Original (2015) | Inflation | Original (2020) | Adjustment Method | Actual Basis | Adjustment Method | Potential Basis |
| Complete System Equipment and Installation | | $12,159,935 | 1.10 | $13,375,929 | Six-Tenths by Capacity | $11,866,967 | Six-Tenths by Capacity | $16,468,204 |
| Capital Recovery Factor (CRF) | CRF (20 yrs, 3.25%) | 0.06878 | CRF (20 yrs, 3.25%) | | CRF (20 yrs, 3.25%) | 0.06878 | CRF (20 yrs, 3.25%) | 0.06878 |
| | | $836,360 | | | | $816,210 | | $1,132,683 |
| **Operating Costs** | | | | | | | | |
| Electricity | | 188953 | 1.10 | $207,848 | Ratio by Capacity | $170,257 | Ratio by Capacity | $293,957 |
| 19% Aqueous Ammonia | | 665665 | 1.10 | $732,232 | Ratio by Inlet NOx | $54,802 | Ratio by Inlet NOx | $218,623 |
| Hydrated Lime | | 361,810 | 1.10 | $397,991 | Ratio by Inlet SO2 | $29,787 | Ratio by Inlet SO2 | $118,829 |
| Labor for Operation and Maintenance | | 69,213 | 1.10 | $76,134 | No Change | 76,134 | No Change | 69,213 |
| Annual Operating Costs | | 1,285,641 | | | | 330,980 | | 700,622 |
| | | | | | | | | |
| Capital Costs | | $12,159,935 | | | | $11,866,967 | | $16,468,204 |
| Annual Capital Costs | | $836,360 | | | | $816,210 | | $1,132,683 |
| Annual Operating Costs | | $1,285,641 | | | | $330,980 | | $700,622 |
| Annual Capital and Operating Costs | | $2,122,001 | | | | $1,147,190 | | $1,833,305 |
| Inlet NOx (tpy) | | 2,300 | | | | 172 | | 687 |
| Inlet SO2 (tpy) | | 511 | | | | 106 | | 289 |
| Inlet PM (tpy) | | 153 | | | | 73 | | 181 |
| Inlet NOx, SO2 and PM (tpy) | | 2,964 | | | | 351 | | 1,156 |
| Outlet NOx (tpy) | | 230 | | | | 17 | | 69 |
| Outlet SO2 (tpy) | | 128 | | | | 26 | | 72 |
| Outlet PM (tpy) | | 6 | | | | 3 | | 8 |
| Outlet NOx, SO2 and PM (tpy) | | 364 | | | | 47 | | 148 |
| Removed NOx (tpy) | | 2,070 | | | | 155 | | 618 |
| Removed SO2 (tpy) | | 383 | | | | 79 | | 217 |
| Removed PM (tpy) | | 147 | | | | 70 | | 173 |
| Removed NOx, SO2 and PM (tpy) | | 2,600 | | | | 304 | | 1,008 |
| Cost Effectiveness ($ per ton removed) | | $816 | | | | $3,768 | | $1,819 |

Notes:

Complete System Equipment and Installation includes: emission control system, controls, infrastructure, engineering design and project management, installation, services, batch recycle system, ammonia tank shelter.

Inflation multiplier from November 2015 to December 2020 = 1.10 - https://www.bls.gov/data/inflation_calculator.htm

Capital Recover Factor based on lifetime of operation and % interest from DOE, Four-Factor Analysis, https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze

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December 3, 2020

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*Submitted via* online public comment forms at:
http://aq.ecology.commentinput.com/?id=Wh9Km (Intalco draft order)
http://aq.ecology.commentinput.com/?id=Yg439 (Alcoa Wenatchee draft order)

Re: NPCA Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County)

Dear Mr. Nguyen and Ms. Schwieters:

On behalf of the National Parks Conservation Association (NPCA), Laumann Legal, LLC. respectfully submits the following comments regarding the Washington Department of Ecology's ("Ecology") proposed source-specific amendments to its Regional Haze State Implementation Plan ("Haze Plan") for two facilities: Alcoa Wenatchee ("Wenatchee") and Alcoa Intalco ("Intalco").

NPCA is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education. NPCA has over 340,000 members nationwide with its main office in Washington, D.C. and 24 regional and field offices. NPCA's regional Northwest office is located in Seattle working on a variety of issues affecting Northwest national parks such as North Cascades, Olympic, and Mt. Rainier National Parks. NPCA is an active nation-wide in advocating for strong air quality requirements in our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, global warming and mercury impacts on parks, and emissions from individual power plants and other sources of pollution affecting National Parks. NPCA's members live near, work at, and recreate in all the national parks of the Northwest, including those directly affected by the Alcoa Intalco Works near Ferndale, Washington and the Alcoa Wenatchee Works in Malaga, Washington. Ecology's proposed source-specific Regional Haze SIP fails to meet the legal requirements of the Clean Air Act and federal regulations and fails to address emissions that cause haze pollutions.

As detailed below, NPCA respectfully requests that the proposed Haze Plan be revised to adequately ensure pollutants from these facilities are enforceably limited.

INTRODUCTION AND BACKGROUND

Washington is home to three national parks, Mount Rainier, Olympic, and North Cascades National Parks, and five wilderness areas, Alpine Lakes, Glacier Peak, Goat Rocks, Mount Adams, and Pasayten Wilderness Areas. Our national parks and wilderness areas are iconic, treasured landscapes and Washington is rich in national parks and natural areas.

Congress set aside these national parks and wilderness areas to protect our natural heritage for generations. Washington's protected areas also generate millions of dollars in tourism revenue, provide habitat for a range of species, and provide year-round recreational opportunities for residents. These special places are designated "Class I areas" under the Clean Air Act ("CAA") and as such, their air quality is entitled to the highest level of protection. Unfortunately, that requirement and promise is unfulfilled because the air in most Class I areas, including in Washington's most treasured natural areas, remains polluted by industrial sources, including the two sources covered by this proposal.

<u>*Alcoa Wenatchee.*</u> Emissions from the Wenatchee facility located at Malaga/Alcoa Highway, Washington, adversely affect visibility at the Alpine Lakes Wilderness Area, located approximately 28 miles west of the facility, at the crest of the Cascade Mountain Range.[1] The Alpine Lakes Wilderness encompasses approximately 394,000 acres in the Central Cascades Region within Washington.[2] The area is accessed by 47 trailheads and 615 miles of trails, including 67 miles of the Pacific Crest National Scenic Trail (PCT).[3] The Enchantment Lakes area contains the Cashmere Crags, which rate among the best rock-climbing

Figure 1. Alpine Lakes Wilderness. (U.S. Forest Service)

[1] 78 Fed. Reg. 79344, 79348-79349. (Dec. 30, 2013).
[2] U.S. Department of Agriculture, Forest Service, Alpine Lakes Wilderness, https://www.fs.usda.gov/recarea/okawen/recarea/?recid=79432 (Nov. 26, 2020).
[3] *Id.*

sites in the western United States. There are more than 700 lakes and mountain ponds in Alpine Lakes, which dot the glacier-carved terrain of this wilderness.[4]

According to NPCA's analysis, emissions from Wenatchee rank the facility third on the list of worst sources of regional haze pollution in the State,[5] with emissions potentially impacting 34 Class I areas, including North Cascades National Park to the northwest and Mount Rainier National Park to the southwest.

The Wenatchee facility consists of a carbon anode production plant, four prebake aluminum potlines, and an ingot casting facility.[6] It initially opened in 1952 with four potlines.[7] In 1967, a fifth potline was added along with increased anode production capability and materials handling operations. In 2018, Line 3, one of the original potlines that had not operated since 2001, was permanently closed, resulting in four remaining potlines.[8] Another line was permanently closed in 2004.[9] At that time, the permanently closed portions were to be evaluated for potential redevelopment.[10] EPA's FIP set new emission limits for specific emission points and a plant-wide limit on the sulfur content of the petroleum coke, representing what the facility emitted, and did not result in any actual emission reductions. The Wenatchee facility has been closed since December 18, 2015, with its reopening uncertain.[11]

*Alcoa Intalco*. Notably, the Intalco facility is the single worst haze polluter at North Cascades National Park, and potentially affects impacts 41 additional Class I areas.

North Cascades has numerous scenic vistas, including its most iconic: Diablo Lake and the intense turquoise hue of its waters,

Figure 2. North Cascades National Park, Diablo Lake. (NPS)

[4] *Id.*
[5] These emissions refer to EPA's 2014 National Emissions Inventory.
[6] 78 Fed. Reg. 79344, 79348-79349. (Dec. 30, 2013).
[7] *Id.* These four potlines and associated processes were constructed prior to the BART window and were not BART-eligible.
[8] *Id.*
[9] "Alcoa Announces Permanent Closure of Wenatchee Works' Line 3 Potline, Aluminum Insider, https://aluminiuminsider.com/alcoa-announces-permanent-closure-of-wenatchee-works-line-3-potline/ (June 20, 2018). Alcoa Corporation, 2018 Annual Report, U.S. SEC Form 10-k, at 13, 46 (In June 2018, one of the four potlines was permanently closed, it had not operated since 2001), http://d18rn0p25nwr6d.cloudfront.net/CIK-0001675149/555ce5d4-26f7-4a23-b242-92bdbfbbfbe2.pdf.
[10] Alcoa News Release, "Alcoa Corporation Provides Update Regarding Wenatchee Smelter in Washington State," (June 18, 2018), "https://investors.alcoa.com/news-releases/news-release-details/2018/Alcoa-Corporation-Provides-Update-Regarding-Wenatchee-Smelter-in-Washington-State/default.aspx.

[11] "Hope dims for Alcoa Wenatchee Works restart," Yakima Herald, https://www.yakimaherald.com/news/business/regional/hope-dims-for-alcoa-wenatchee-works-restart/article_172bbf02-73d5-11e8-90b6-b3ca3455b194.html (June 19, 2018).

created by the glacier-ground rock powder that is carried to the lake via creeks.

The visibility-impairing pollutants are PM, $SO_2$, and $NO_X$, which significantly and adversely affect the air quality in Olympic National Park, as well as five other Washington Class I areas (Alpine Lakes, Glacier Peak, Mount Rainer and North Cascades).[12] The major sources of these pollutants at the Intalco facility are the potlines and to a lesser extent, the anode bake furnace. According to NPCA analysis, emissions from Intalco rank the facility second on the list of worst sources of regional haze pollution in the State.[13] Washington's 5-year regional haze progress report acknowledged that the SO2 emissions from Intalco, and to a lesser extent the Wenatchee facility, create a challenge to additional visibility improvement in North Cascades and Olympic National Park.[14]

EPA finalized a limited approval and limited disapproval of the State's $SO_2$ BART determination and promulgated a Federal BART alternative for the potlines, the only units at the Intalco facility subject to BART.[15] EPA took no action on the remaining units, which, in addition to the BART units, are covered by the reasonable progress requirements.[16] The State's draft Order indicates that Alcoa 'curtailed" production at the Intalco facility in August 2020.[17] Prior to the closure, emissions had increased due to fluctuations in the market price of aluminum and the corporate decision in 2007 to ramp up production to nearly full capacity.[18]

Therefore, both Alcoa Wenatchee and Alcoa Intalco are closed and neither facility produces aluminum. While different terms are used to describe the facility status (e.g., closed, curtailed, fully curtailed idle, temporarily closed, fully shut down),[19] for consistency our comments use "closed" to describe the current status of both facilities.

To improve air quality in our most treasured landscapes, Congress passed the visibility protection provisions of the Clean Air Act in 1977, establishing "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in the

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[12] 77 Fed. Reg. at 76,174, 76,191 (Dec. 26, 2012).
[13] The facility was originally constructed in 1965, began operation in 1966.
[14] Department of Ecology, State of Washington, "Washington State Regional Haze 5-Year Progress Report," at 213, (Sept. 2017), https://www.regulations.gov/document?D=EPA-R10-OAR-2018-0001-0004. (Progress Report)
[15] 79 Fed. Reg. 33438 (June 11, 2014); 40 C.F.R. § 52.250 (Best available retrofit technology requirements for the Intalco Aluminum Corporation (Intalco Works) primary aluminum plant—Better than BART Alternative, limiting the SO2 emissions from the plant and establishing monitoring and reporting requirements). EPA took no action on the remaining units, which, in addition to the BART units, are covered by the reasonable progress requirements.
[16] Progress Report at 15.
[17] "Alcoa to shut Ferndale smelter, putting 700 out of work," Wenatchee World, https://www.wenatcheeworld.com/business/alcoa-to-shut-ferndale-smelter-putting-700-out-of-work/article_e98689d6-c7c1-57fd-96e7-34992a5785dd.html (April 23, 2020)(The direct effect of Alcoa's decision was the loss of 700 jobs as the facility.)
[18] Washington State Regional Haze 5-Year Progress Report, at 15-16 (Sept. 2017), https://www.regulations.gov/document?D=EPA-R10-OAR-2018-0001-0004.
[19] Alco Annoucement, "Alcoa Corporation Announces Full Curtailment of Intalco Works," (April 22, 2020)(Attachment 3). *See also* "Looming closure of Alcoa aluminum plant in Ferndale threatens to leave hundreds jobless, King5, https://www.king5.com/article/money/economy/alcoa-workers-rally-to-save-ferndale-plant/281-dd42e1da-39fe-4494-8584-e2e85fac4e81 (April 23, 2020)("Earlier in the week the company announced it is shutting the plant down, putting some 700 people out of work. … The company plans to shutter the plant by the end of July."); "Intalco's closure brings pain for now — what may the future bring?")

mandatory class I Federal areas which impairment results from manmade air pollution."[20] "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities."[21] In order to protect Class I areas' "intrinsic beauty and historical and archeological treasures," the regional haze program establishes a national regulatory floor and requires states to design and implement programs to curb haze-causing emissions within their jurisdictions. Each state must submit for EPA review a SIP designed to make reasonable progress toward achieving natural visibility conditions.[22]

A regional haze SIP must provide "emissions limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal."[23] Two of the most critical features of a regional haze SIP are the requirements for installation of Best Available Retrofit Technology ("BART") limits on pollutant emissions and a long-term strategy for making reasonable progress toward the national visibility goal.[24] The haze requirements in the Clean Air Act present an unparalleled opportunity to protect and restore regional air quality by curbing visibility-impairing emissions from some of the nation's oldest and most polluting facilities.

Implementing the regional haze requirements promises benefits beyond improving views. Pollutants that cause visibility impairment also harm public health. For example, oxides of nitrogen ("$NO_X$") are a precursor to ground-level ozone which is associated with respiratory disease and asthma attacks. $NO_X$ also reacts with ammonia, moisture and other compounds to form particulates that can cause and/or worsen respiratory diseases, aggravate heart disease, and lead to premature death. Similarly, sulfur dioxide ("$SO_2$") increases asthma symptoms, leads to increased hospital visits, and can also form particulates.[25] $NO_X$ and $SO_2$ emissions also harm terrestrial and aquatic plants and animals through acid rain as well as through deposition of nitrates (which in turn cause ecosystem changes including eutrophication of mountain lakes).

Unfortunately, instead of acting on Congress's direction, the states and EPA have repeatedly dragged their feet in implementing the visibility protection provisions, which is true in Washington. After failing to control visibility impairing pollutants for these two sources during the first planning period, the Department of Ecology yet again proposes SIP provisions that delay the required reasonable progress analysis and lack enforceable and permanent emission reducing measures. The State's proposals fail to meet the Act's requirements because it would allow both sources to restart, allowing emissions from these sources to impact the Class I areas, leaving them dirty for years to come. Ecology's proposal must be revised to adequately control emissions and contain enforceable and permanent measures in this planning period to ensure the Clean Air Act's regional haze SIP requirements are met from these sources. As discussed in our comments, these measures must be in place before either source restarts.

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[20] 42 U.S.C. § 7491(a)(1).
[21] *Id.* § 7491(g)(3).
[22] *Id.* § 7491(b)(2).
[23] 42 U.S.C. § 7491(b)(2).
[24] *Id.* § 7491(b)(2)(A); 40 C.F.R. § 51.308(d)(1)(i)(B).
[25] Emissions from Intalco not only impact Class I areas, but as explained in the State's notice for the Intalco Draft Order, EPA is in the process of making a determination whether to designate part of Whatcom County near the smelter to be in non-attainment for the 2010 1-hour SO2 NAAQS.

## I. Washington's Proposed State Implementation Plan Revisions Do Not Meet the Regional Haze Reasonable Progress Requirements

In developing its long-term strategy, a state must consider its anthropogenic sources of visibility impairment and evaluate different emission reduction strategies including and beyond those prescribed by the BART provisions.[26] A state should consider "major and minor stationary sources, mobile sources and area sources."[27] At a minimum, a state must consider the following elements:

> (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
> (B) Measures to mitigate the impacts of construction activities;
> (C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
> (D) Source retirement and replacement schedules;
> (E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
> (F) Enforceability of emission limitations and control measures; and
> (G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.

40 C.F.R. § 51.308(d)(3)(v)(A)-(G). Additionally, a state "must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated."[28] In developing its plan, the State must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based.[29] A state's reasonable progress analysis must consider the factors identified in the Clean Air Act and regulations. *See* CAA 169A(g)(1); 40 C.F.R. 51.308(d)(1)(i)(A)("Consider 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 sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.") Finally, the state's SIP revisions must meet certain consultation and procedural requirements (e.g., the state must provide the Federal Land Manager(s) with an opportunity to consult and comment, and there is no information indicating that consultation occurred for these proposed SIP revisions; [30] and the state must provide for public hearing, which has also not been provided.[31])

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[26] 40 C.F.R. § 51.308(d).
[27] *Id.*
[28] 40 C.F.R. § 51.308(f)(2)(i).
[29] 40 C.F.R. § 51.308(d)(3)(iii).
[30] 40 C.F.R. § 51.308(i).
[31] 40 C.F.R. § §  51.104, 51.102.

### A. The Intalco and Alcoa Facilities Are Subject to the Reasonable Progress Requirements

The State's proposed SIP revisions cover two major stationary sources, the Intalco and Wenatchee facilities. The draft Orders for the sources explain that based on the facilities' 2014 emission inventories, "Ecology has determined that it is appropriate to include the facility as a source to be evaluated for regional haze impacts."[32] The draft Order for Intalco, further explains that:

> Per 40 C.F.R. § 51.308, Ecology conducted a screening of major facilities by summing the Regional Haze producing emissions (NOx, PM2.5, SO2, and H2SO4) for each facility (Q) and dividing by the distance to the closest Class I Area (d). Ecology selected facilities with Q/d values greater than 6.7 as well as facilities that contributed more than 80 percent of the total summed Q/d for a Four-Factor Analysis.[33]

Similarly, the draft Order for Wenatchee, explains that:

> Per 40 C.F.R. § 51.308, Ecology conducted a screening of major facilities by summing the Regional Haze producing emissions (NOx, PM2.5, SO2, and H2SO4) for each facility (Q) and dividing by the distance to the closest Class I Area (d). Ecology selected facilities with Q/d values greater than 6.7 as well as facilities that contributed more than 80 percent of the total summed Q/d for a Four-Factor Analysis.[34]

Based on the emissions and Class I area impacts, Ecology determined both facilities are subject to the reasonable progress analysis. Rather than conduct its own reasonable progress analysis, Ecology sent letters notifying Intalco and Alcoa that the respective facilities (Intalco Aluminum facility and Alcoa Wenatchee Works) were selected as facilities requiring a Four-Factor Analysis based on the 2014 emission inventory data.[35]

### B. Washington's Proposed SIP Revisions Fail to Include the Required Four-Factor Analysis

Washington's proposed SIP revisions merely include draft Orders. The proposals fail to include the required reasonable progress Four-Factor Analysis or an enforceable requirement that the facility is shutdown and must apply for new air permits and associated reasonable progress

[32] Draft Intalco Aluminum LLC, Regional Haze Agreed Order No. 18216, at 2 (undated)("Intalco Order"); Draft Alcoa Wenatchee Works, Regional Haze AO No. 18100, at 2 (undated)("Alcoa Order").

[33] *Id.* Although the State explains it conducted a screening of all facilities, this proposal only includes some of the information for two of those facilities. Since this proposal fails to provide for emission limitations, the State is unable to explain how what it proposes for these facilities are adequate to meet the overall reasonable progress requirements statewide.

[34] *Id.*

[35] *Id.* The supporting analysis and information is missing, should be made available, and is foundational to public knowledge of the facilities' past and potential projected impacts. (e.g., Ecology's proposal does not provide a citation for how and where the emission inventory was obtained; the SIP proposal does not include copies of the letters sent to the sources, nor does it include the responses from the sources; there's no basis for the screening method; no basis for the cut off level used for screening).

and other analyses should it endeavor to come back online. As detailed in these comments, while we have concerns about Ecology's efforts thus far, Ecology has only done part of its job. Thus far, Ecology:

- Evaluated the emissions from these sources and impacts to the Class I area, calculated a Q/d value, and

- Based on the Q/d values, determined that a Four-Factor Analysis is required for the Intalco and Wenatchee facilities.

Ecology cannot stop here. As clearly laid out in EPA's regulations, the duty to ensure the reasonable progress requirements are met for purposes of the SIP rests with the state, not the sources. If the companies are unwilling to respond to Ecology's May 31, 2019, letters, which asked the companies to conduct a Four-Factor Analysis, Ecology must conduct the analyses to inform its reasonable progress determination. While a state may certainly ask that a source conduct and submit a Four-Factor analysis, a state can't ignore the rule requirements if it fails to receive the analysis from a source.[36]

Ecology appears to suggest that its proposed Orders are justified because the Alcoa "facility has been curtailed since December 18, 2015" and the Intalco "facility fully curtailed its operations at the end of August 2020." Neither the Clean Air Act nor the regional haze regulations include provisions that allow a state to take a pass on emission control requirements because a facility is closed. Indeed, Ecology's Orders provides no authority for such a deferral.

Ecology has two options in this SIP revision: (1) conduct the required four-factor analysis for these two sources, and issue requirements for emission limitations and other measures; or (2) revise the SIP to void the current permits and include requirements for the sources to obtain new construction and operating permits prior to restarting operation.

## II. If Washington Proceeds without the Required Reasonable Progress Analysis, the SIP Must Contain Provisions to Ensure Permits *Complement* the Act's Reasonable Progress Requirements

The Clean Air Act requires states to submit implementation plans that "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of achieving natural visibility conditions at all Class I Areas.[37] The Regional Haze Rule requires that states must revise and update its regional haze SIP, and the "periodic comprehensive revisions must include the "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress as determined pursuant to [51.308](f)(2)(i) through (iv)."[38] The State's proposal is merely a commitment to do something in the future: it lacks the required Four-Factor

[36] Under the Act's cooperative federalism structure, when a state fails to meet these requirements, EPA is required to step in and promulgate a FIP (which EPA was forced to do in the first round of regional haze for the State for these two facilities).
[37] 42 U.S.C. § 7491(a)(1), (b)(2).
[38] 40 C.F.R. § 51.308(f)(2); 40 C.F.R. § 51.308(d)(3)(v)(F)(Enforceability of emission limitations and control measures).

Analysis, emission limitations and other requirements necessary. Furthermore, EPA's Guidance further explains these requirements:

> This provision requires SIPs to include enforceable emission limitations and/or other measures to address regional haze, deadlines for their implementation, and provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.[39]

Washington's proposed SIP revisions do not include emissions limitations with practicably enforceable provisions. Rather, they contain provisions for potential future action, requiring the sources to "install or otherwise implement all reasonable emission reduction measures that are identified in the Four-Factor Analysis and subsequently approved by Ecology."[40] Moreover, EPA's recent Guidance recognizes EPA's long-standing position that while the SIP is the basis for demonstrating and ensuring state plans meet the regional haze requirements, state-issued permits must complement the SIP and SIP requirements.[41] State-issued permits must not frustrate SIP requirements.[42] For example, sources with PSD permits under Title I must not hold permits that allow emissions that conflict with SIP requirements.[43] Additionally, the Act's Title V operating permits collect and implement all the Act's requirements – including the requirements in the SIP – as applicable to the particular permittee. And sources with Title V permits must not hold such permits if they contain permit terms and conditions that conflict with the SIP and Clean Air Act SIP requirements.

The proposed SIP revisions for these two sources lack the required "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" and thus would allow both companies to restart and operate without first meeting the regional haze requirements. The draft Orders allow the currently closed sources to restart with emissions at levels that impact the Class I areas for many years without first meeting reasonable progress emission limitation and other necessary requirements.[44] Contrary to the requirement to ensure permits complement the SIP, Washington's proposed SIP revisions do

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[39] "EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," at 42-43 (August 20, 2019), https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf. (While NPCA filed a Petition for Reconsideration regarding EPA's issuance of the 2019 Guidance (Attachment 2), it does not dispute the information in the Guidance referenced here regarding enforceable limitations, which cite to the "General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990, 74 Fed. Reg. 13498 (April 16, 1992)..

[40] Intalco Draft Order at 1, Wenatchee Draft Order at 1.

[41] 74 Fed. Reg. 13498, 13568 (April 16, 1992).

[42] Furthermore, to the extent stationary source are granted permits by rule or other mechanisms, these other categories that allow construction and operation must also complement SIP requirements.

[43] Additionally, the proposed SIP revisions fail to contain source-specific "measures to mitigate the impacts of construction activities." 40 C.F.R. § 51.308(d)(3)(v)(B).

[44] The draft Orders find that for Alcoa and Intalco, the facility's Q/d value was "greater than 6.7" and it "contributed more than 80 percent of the total summed Q/d for a Four-Factor Analysis" Alcoa Order at 2; and Intalco Order at 2. Furthermore, the draft Orders fail to include Ecology's review of the future Four-Factor Analysis, its proposed determinations, and public notice and comment on the proposed SIP, Furthermore, the draft Orders do not disclose that once the State adopts the SIP provisions, they must be submitted to EPA for review and approval. Therefore, given the time necessary for the State's and EPA's rulemaking process, if Ecology were to adopt SIP provisions, it would be many more years before such provisions were enforceable as a matter of federal law.

nothing to address the PSD permits issued to Wenatchee[45] and Intalco.[46] The revised SIPs must make clear that reactivation of either facility means it will be treated as operation of a new source for purposes of PSD. Attachment 1 to these comments contains 13 additional concerns with the draft Orders.

Ecology issued Title V permits to both sources, which Ecology suggests are still effective.[47, 48] Based on the information referenced in the proposal, the Title V permits expired and the sources do not have valid Title V permits.[49] Washington has no information on its website to indicate either facility submitted a timely and complete application to renew its Title V permit and demonstrate an intent to reopen. Therefore, the revised SIP must include provisions that make enforceable the retirement of these facilities as part of this action and also require that the sources each obtain a new Title V permit compliant with the regional haze program should the intend to restart.[50]

Washington cannot cover its eyes and act as if emissions from these sources cannot exist or that it is relieved of its obligation to address visibility impairing emissions from sources. Therefore it must revise the SIP to ensure that the reasonable progress measures and Clean Air Act permits properly support the requirements that must be in the SIP.[51]

Finally, it appears the proposed SIP revisions were negotiated between the State and the company, other stakeholders were not invited to participate. In the future, as EPA does, we urge Washington to invite stakeholders to the table when its rule is negotiated.[52]

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[45] Furthermore, Wenatchee shutdown in 2015. Thus, under EPA's well-established PSD Reactivation Policy it is shutdown of greater than two years and is presumed permanent. *See In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc., Proposed Operating Permit*, Petition No 6-99-2 (June 11, 1999), https://www.epa.gov/sites/production/files/2015-07/documents/ccaw_ord.pdf

[46] Ecology's website includes the Alcoa Intalco Ferndale PSD permit issued 10/17/1984 (No. PSD-2). However, while the Title V Operating Permit for Wenatchee (No. 000068-0) references PSD-X82 04, at 28, the PSD permit information for the Alcoa Wenatchee plant incorrectly links to the 10/17/1984 Intalco permit. No other construction permits or information was found on Ecology's website for the facilities.

[47] The Intalco Air Operating Permit No. 000295-1 expired on December 31, 2019. The Wenatchee Air Operating Permit No. 000068-0 expired on April 1, 2015 (cites PSD-X82 04).

[48] While Ecology's proposed Orders refer to some existing permits, the Orders fail to include provisions revising the permits so that the permits support the SIP. The draft Order's merely require the following: "Nothing in this Order shall in any way relieve Alcoa of its obligations to comply with the requirements of its Air Operating Permit No. 000068-0 or any other requirements of the law. Nor shall anything in this Order limit Ecology's authority to enforce the provisions of the aforementioned Permit or the CAA"[48] Alcoa Order at 2; and "Nothing in this Order shall in any way relieve Intalco of its obligations to comply with the requirements of its Air Operating Permit No. 000295-0 or any other requirements of the law. Nor shall anything in this Order limit Ecology's authority to enforce the provisions of the aforementioned Permit or the CAA." Intalco Order at 2.

[49] The Title V Operating Permits for these sources have expired: Alcoa Intalco Ferndale Title V operating permit, expired on 12/31/2019 and the Alcoa Wenatchee Title V operating permit, expired on 4/1/2015.

[50] Appears expired without timely renewal application.

[51] 74 Fed. Reg. 13498, 13568 (April 16, 1992).

[52] Federal Advisory Committee Act (FACA) of 1972 (Public Law 92-463).

## CONCLUSION

NPCA urges Ecology not to finalize the Washington haze SIP revisions as proposed. Ecology has inappropriately excused and delayed Intalco and Alcoa from meeting the reasonable progress requirements, which is inconsistent with the statutory command to require reasonable progress. Ecology's proposal fails to include the required Four-Factor Analysis or establish measures for these sources that make retirement of these sources enforceable in the regional haze SIP. Furthermore, the proposed SIP revisions fail to include provisions necessary to ensure that should either facility restart, new Ecology-issued permits be required and complement – rather than thwart – SIP requirements. Ecology's proposals for these facilities are inadequately supported and not in keeping with the requirements of the law. NPCA strongly encourages the State of Washington to go back to the drawing board and prepare a reasonable progress SIP for these sources that is consistent with the Act and regulatory requirements, including consideration of retiring the current permits.

Please feel free to contact the undersigned should you have any questions regarding these comments.

Sincerely,

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Attachments

# Attachment 1

## The Draft Orders Fail to Comply with the Act's Requirements

The draft Orders are arbitrary, capricious and contrary to the requirements of the Act and regulations for numerous other reasons.

1. The draft Orders indicate they are effective on signature, recommend clarification that they must be submitted to EPA for review and final action (approval/disapproval).
2. The draft Orders allow the State to revise the Orders without going through the SIP public notice and comment process, and EPA submittal and action.
3. There are no deadlines requirements for Ecology to make a final decision regarding the Four-Factor Analyses. Ecology could take months or years to act on the submissions from the companies. The Orders must include deadlines for Ecology to act.
4. The draft Orders fail to contemplate a situation where the companies fail to provide the additional information Ecology requests. The Orders must recognize that Ecology retains responsibility to conduct the Four-Factor Analysis.
5. Section V of the draft Orders allows Ecology to change the conditions of the Order, without first providing for public notice and comment, and submittal to EPA for approval
6. In conducting the Four-Factor Analysis, the draft Orders allow the sources to take credit for emissions that have not occurred ("The analysis will be based on the facility's permitted emission limits…"[53]), which is prohibited. Emission measures must reflect quantifiable emission reductions and be real. Reductions from permitted levels, unless they represent real emissions, do not meet this requirement. Furthermore, if permit limits exceed CAA requirements, emissions in violation of those requirements cannot be counted as reductions.
7. There are no control measures and reasonable progress emission limits in the draft Orders. Therefore, there are no measures to enforce.
8. The draft Orders lacks recordkeeping, monitoring and recording requirements.
9. The draft Orders merely cover restart of the potlines, which is contrary to Ecology's determination that emissions from the entire facilities are subject to reasonable progress.
10. The draft Orders do not require that the facilities do anything now. Rather, they have until at least 180 days prior to restarting any of the facilities potlines, at which point they must prepare and submit a Four-Factor analysis to Ecology.
11. The draft Orders require the sources to install or otherwise implement and begin operating all emission control measures identified in the final Four-Factor Analysis within three years of Ecology's approval. The draft Order fails to disclose that the Analysis will be subject to EPA's review and final action (approval/disapproval). Thus, if the sources install and implement requirements prior to EPA's review, they assume the risk that EPA may

[53] Alcoa Order at 2, Intalco Order at 2.

disapprove the State's proposal and that they will need to install and implement other requirements.

12. The draft Orders allow the companies to not comply with the Order, as long as they receive approval from the State. SIPs cannot contain variance provisions that allow the sources to violate the Order.
13. The draft Orders contains language that allows them to terminate. As SIP provisions must be permanent, it is unclear how an Order that allows for termination meets those requirements.

**Attachment 2**

May 8, 2020

***Via Federal Express and Email***

Administrator Andrew Wheeler
Office of the Administrator
United States Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460
Wheeler.andrew@epa.gov

**Re: Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period**

Dear Administrator Wheeler:

I. Introduction

National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Western Environmental Law Center, Appalachian Mountain Club, Coalition to Protect America's National Parks, and Earthjustice (hereinafter "Conservation Organizations") hereby petition[1] the Administrator of the United States Environmental Protection Agency ("EPA") to reconsider the entitled "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (hereinafter "Final Guidance" or "Guidance")[2] and replace it with

[1] This Petition is filed pursuant to section 4(d) of the Administrative Procedure Act ("APA"), 5 U.S.C. § 553(e), and, to the extent it may be applicable and relevant, section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B).
[2] EPA issued the Final Guidance on August 20, 2019 via Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards to EPA Air Division Directors.

guidance that comports with the Clean Air Act ("CAA") and the Regional Haze Rule, and aids states in making progress towards achieving the national goal of natural visibility conditions at all Class I areas.[3] The Final Guidance is a significant departure from the Draft Guidance[4] issued in 2016 for the second planning period and contains provisions that are expressly at odds with the Clean Air Act and Regional Haze Rule. The table below summarizes how key provisions of the Final Guidance should be revised to comply with the requirements of the applicable statutes and regulations.

The Guidance unlawfully directs states on how they may exclude certain emission sources from four-factor consideration and delay or altogether avoid reducing emissions necessary to meet Congress's mandate that the states make reasonable progress towards the national goal of restoring natural visibility to Class I area national parks and wilderness areas. 42 U.S.C. § 7491(b)(2). The Guidance not only conflicts with the text and purpose of the Clean Air Act and the Regional Haze Rule itself, but it conflicts with EPA's 2016 Draft Guidance by arbitrarily constraining EPA review authority, diminishing the science of regional haze, and recasting technical and analytical requirements for State Implementation Plans ("SIPs"). Implementation of the Final Guidance will result in inconsistencies between SIPs, create arbitrary exceptions allowing states to avoid controlling emission sources, impede progress toward the national goal of a restoring natural visibility, and may actually degrade visibility at some Class I areas.

| Section of the Petition | Summary of Issue | Applicable Regional Haze Rule or other Regulations[5] |
|---|---|---|
| III.A. | States must comprehensively identify sources of human-caused visibility-impairing emissions across source categories and cannot arbitrarily defer some sources to another implementation period. | Section 51.308(f)(3)(ii) of the Regional Haze Rule and Clean Air Act section 169A(b) |
| III.B. | States have only limited discretion to decide which sources they consider for reasonable progress. SIPs will be found deficient where they fail to require emission reductions that collectively make reasonable progress towards natural visibility at all Class I areas in each planning period; no backsliding is permitted. | 82 Fed. Reg. at 3,088 and sections 51.308(f)(2)(i), 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B) |
| III.C. | States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire. | Sections 51.308(f)(2)(i), 51.308(f)(2)(iv)(C) |

[3] 42 U.S.C. §§ 7491, 7492; 82 Fed. Reg. 3078 (Jan. 10, 2017); 71 Fed. Reg. 60,612 (Oct.13, 2006); 70 Fed. Reg. 39,104 (July 6, 2005); 64 Fed. Reg. 35,714 (July 1, 1999).
[4] Draft Guidance on Progress Tracking Metrics, Long-term strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, (hereinafter "Draft Guidance") 81 Fed. Reg. 44,608 (July 8, 2016).
[5] Clean Air Act section 110(k)(5) provides EPA the authority to review a SIP and assess the adequacy of that SIP. Therefore any aspect of this guidance that interferes with that authority is in conflict.

| | | |
|---|---|---|
| III.D. | States cannot consider being under the uniform rate of progress (“URP”) when selecting sources for a four-factor analysis. The glidepath is not a safe harbor; rather a state must take measures necessary to make progress towards natural visibility at any Class I areas its emissions affect. | 82 Fed. Reg. at 3,093 |
| III.E. | Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control. | Section 51.308(f)(2)(iv)(D) |
| III.G. | States must include both “dominant” and “non-dominant” pollutants in their analyses of controls. | 82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)( (B), 51.308(f)(2)(i) |
| III.H. | States cannot eliminate volatile organic compounds (“VOCs”) and ammonia emissions from consideration. | 82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B), 51.308(f)(2)(i) |
| IV.A. | States must use methods permitted by statute and regulation to identify its sources that potentially affect visibility at Class I areas in other states, not merely any “reasonable method.” | 82 Fed. Reg. at 3,094 and sections 51.308(f)(2)(i), 51.308(d)(3)(iv) |
| IV.B. | States must consider cumulative impacts of sources or groups of sources to all affected Class I areas. | Section 51.308(f)(2)(i) |
| V.A. | States must prioritize emissions within their borders to achieve reasonable progress. | Sections 51.308(f)(1)(vi)(B), 51.308(f)(2)(iv)(D), and Clean Air Act section 169A(b) |
| VI.B. | States must adhere to the accounting principles of the Control Cost Manual and should compile and make publicly available the documentation for generic cost estimates. | Section 51.308(f)(2)(i) |
| VII.A. | States cannot allow sources to discontinue the use of currently operating controls. | Section 51.308(f)(2) and Clean Air Act section 169A(b)(2) |
| VIII | States should use regional scale modeling to support their regional haze SIPs. | Section 51.308(f)(3)(ii)(A), Appendix W to Part 51 |
| IX.A. | If a state’s reasonable progress goal (“RPG”) is above the URP, the state’s “robust demonstration” must include a consideration of specific items identified by EPA. | Section 51.308(f)(3)(ii) |
| X.A. | States must submit to EPA the emission inventory used in a regional haze SIP. | Section 51.308(f)(2)(iii), Clean Air Act section |

| | | |
|---|---|---|
| | | 110(k)(5), and EPA's Emission Inventory Guidance[6] |
| X.B. | States must ensure that Federal Land Managers' ("FLMs") opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP. | Sections 51.308(i), 51.308(f)(4) and Clean Air Act sections 169A(a) and (d) |
| XI.B. | Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations. | Section 51.308(f)(2)(i) |
| XI.C. | EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility. | Clean Air Act section 169A(a) |

This Petition seeks reconsideration and substantial revision of the Final Guidance so that the Guidance will direct states to deliver on the statutory objective of preventing future and remedying existing Class I area visibility impairment that results from human-caused pollution. As issued, the Final Guidance conflicts with this statutory objective, previous rulemaking and guidance; misdirects states as to how they can go about complying with their legal obligations to make reasonable progress towards restoring natural visibility to protected public lands; and otherwise fails to set expectations that comport with legal requirements for the second planning period.

In addition to the provisions noted in the table above, the Conservation Organizations incorporate several recommendations from their Comments on EPA's Draft Guidance[7] and request that EPA reconsider and revise the Final Guidance to direct states with regard to the following issues:

- States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.
- Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.
- States should include all visibility-impairing pollutants when calculating a source's annual emissions.
- States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

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[6] EPA, Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations (May 2017), https://www.epa.gov/sites/production/files/2017-07/documents/ei_guidance_may_2017_final_rev.pdf.
[7] Conservation Organizations incorporate by reference their full Comments on the 2016 proposed Draft Guidance.

- States should analyze the climate and environmental justice impacts of measures to achieve reasonable progress.

The gains made in the first regional haze planning period established a critical, if delayed, foundation for our national parks and wilderness areas to make progress towards the natural visibility which they and their visitors and neighboring communities are due. The Final Guidance not only hinders future gains but in some cases actually jeopardizes the gains made in the first planning period. Conservation Organizations urge EPA to reconsider its Final Guidance and instead issue a revised guidance that directs states to fulfill regulatory requirements for reasonable progress in the second planning period to help attain clearer skies at America's prized national parks and wildernesses.

II. SIP development steps

As EPA states in the Final Guidance, the key steps to developing a regional haze SIP start with identifying the twenty percent most anthropogenically impaired days and the twenty percent clearest days and determining baseline, current, and natural visibility conditions for each Class I area within the state, and then determining which Class I area(s) in other states may be affected by the state's own emissions.[8] States must then screen sources and conduct a four-factor analysis of which controls are required before establishing reasonable progress goals.[9] Once a state has determined the reasonable progress measures to require at specific sources, the state must quantify the "reasonable progress goal"—i.e., the visibility improvement that will result from implementing the controls merited by a four-factor analysis.[10] Additional steps include regional scale modeling of the long-term strategy to set the RPGs for 2028 and progress, degradation, and URP glidepath checks.[11]

Some of the most problematic provisions of the Final Guidance, which are contrary to several requirements of the Regional Haze Rule and Clean Air Act, involve the selection of sources for analysis. After discussing these provisions, this Petition discusses the determination of affected Class I areas in other states, ambient data analysis, the characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, regional scale modeling of the long-term strategy to set the RPGs for 2028, progress, degradation, and URP glidepath checks, and additional requirements for regional haze SIPs. After addressing how these various provisions of the Guidance are contrary to the regulatory requirements, the Petition provides several overarching recommendations that EPA should consider when revising the Guidance, including advising states that in order for a SIP to be approvable it must result in measures to reduce visibility impairing pollution beyond those required from the past planning period and reflective of an adequate reasonable progress analysis.

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[8] Final Guidance at 5.
[9] *Id.*
[10] *Id*.
[11] *Id.* at 5-6.

III. Selection of sources for analysis

A. Selection of sources under section 51.308(f)(3)(ii)(A).

In the Final Guidance, EPA presents a statement at the beginning of the section II.B.3 that is in conflict with the Regional Haze Rule's requirements:

> A key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures. . . . Accordingly, it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods.[12]

This statement by EPA is contrary to the requirements in section 51.308(f)(3)(ii) of the Regional Haze Rule and section 169A(b) of the Clean Air Act.

In a footnote, EPA indicates that "analysis of control measures" refers to an analysis of what emission control measures for a particular source are necessary in order to make reasonable progress and must include consideration of the four statutory factors and consideration of the five additional factors listed in 40 C.F.R. § 51.308(f)(2)(iv).[13] This important requirement of how sources should be selected by states for analyses is presented as if it were a secondary consideration. In other words, EPA's Guidance now advises states that they can arbitrarily delay the selection of sources for evaluation, or exclude certain sources as noted *infra*, and thereby "distribute [their] analytical work" and the "compliance expenditures of source owners" as if it is a stand-alone, top-level decision that states can make, divorced of the need to apply the four statutory factors and the five additional factors to actually make reasonable progress.

If a state were to arbitrarily "distribute its own analytical work, and the compliance expenditures of source owners, over time"[14] as the guidance provides, it would not be able to address section 51.308(f)(3)(ii)(B), which requires:

> If a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State for which a demonstration by the other State is required under (f)(3)(ii)(A), the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to

[12] *Id.* at 9.
[13] *Id.* at 9 n.22.
[14] *Id.* at 9.

> include in its own long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy.

A state that arbitrarily excludes sources from consideration cannot determine if it actually has "sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area." To satisfy that requirement, a state must first have a reasonable understanding of the emissions from all of its sources and it must have a reasoned methodology for excluding sources from a four-factor analysis (e.g., those sources are inconsequential or do not have cost-effective control options). Similarly, if a state, which arbitrarily excludes sources from evaluation, has a RPG that is above the URP, it cannot satisfy section 51.308(f)(3)(ii)(A)[15], which requires that it demonstrate "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." In contrast, not only was this advice absent from EPA's Draft Guidance, the Draft Guidance provided detailed, valid information on source selection.[16]

Additionally, as mentioned *infra* section IV.A, the Final Guidance also arbitrarily allows states to decide whether they contribute to out-of-state Class I areas by claiming states can use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas.[17] The Final Guidance also allows a state to disregard its impacts on an out-of-state Class I area that a neighboring state may identify as being affected by emissions from the state developing the long-term strategy.[18] By allowing states to arbitrarily make these determinations, EPA is attempting to slice the program into inconsequential bits and pieces that set the

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[15] EPA noted in the 2017 Regional Haze Rule revision:

[I]n a situation where the RPG for the most impaired days is set above the glidepath, a contributing state must make the same demonstration with respect to its own long-term strategy that is required of the state containing the Class I area, namely that there are no other measures needed to provide for reasonable progress. The intent of this proposal was to ensure that states perform rigorous analyses, and adopt measures necessary for reasonable progress, with respect to Class I areas that their sources contribute to, regardless of whether such areas are located within their borders.

82 Fed. Reg. at 3099. *See also* 81 Fed. Reg. 66,331, 66,631 (Sept. 27, 2016) ("[A]n evaluation of the four statutory factors is required . . . regardless of the Class I area's position on the glidepath. . . . [T]he URP does not establish a 'safe harbor' for the state in setting its progress goals."); 81 Fed. Reg. 295, 326 (Jan. 5, 2016) ("[T]he uniform rate of progress is not a 'safe harbor' under the Regional Haze Rule"); EPA, Guidance for Setting Reasonable Progress Goals under the Regional Haze Program (hereinafter "RPGs Guidance") (June 2007) 4–1, https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.

[16] Draft Guidance at 57-83.

[17] Final Guidance at 8.

[18] *Id.* at 9.

provisions of the Final Guidance against fulfilling the requirements of the Clean Air Act and Regional Haze Rule that compel a comprehensive "regional" approach to restoring visibility. EPA should strike the above-mentioned language discussing selection of sources under section 51.308(f)(3)(ii)(A) from the Final Guidance and restore the language from the Draft Guidance.

B. States have only limited discretion to decide which sources they consider for reasonable progress.

In Section II.B.3.d of the Final Guidance, EPA states, "[t]he source-selection step is intended to add flexibility and discretion to the state planning process – ultimately, the state decides which sources to consider for reasonable progress."[19] This blanket statement, written as if a state has unbounded discretion to determine which sources it evaluates under reasonable progress, is incorrect. A state cannot arbitrarily determine which sources it evaluates under the Regional Haze Rule's reasonable progress requirements. Ultimately, a state's source selection criteria is a part of its long-term strategy. As EPA indicated in the Regional Haze Rule revision, a state does not have discretion to arbitrarily exclude sources from a four-factor analysis. Specifically, EPA stated:

> [W]e expect states to exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze. Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by arbitrarily including costly controls at sources that do not meaningfully impact visibility or failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a [Federal Implementation Plans ("FIPs")]. [20]

A state with a RPG below the URP that followed this guidance and arbitrarily excluded sources from a four-factor analysis runs afoul of section 51.308(f)(3)(ii)(A), which requires a "robust demonstration" that "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." If a state that followed this guidance had emission sources that potentially affect visibility at a Class I area in another state, it would similarly be unable to satisfy the same requirement found in section 51.308(f)(3)(ii)(B). EPA should reconsider this provision, and delete it from the Final Guidance.

C. States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.

[19] Final Guidance at 20.
[20] 82 Fed. Reg. at 3088.

In Section II.B.3.d of the Final Guidance, EPA also states "[i]f a source is expected to close by December 31, 2028, under an enforceable requirement, a state may consider that to be sufficient reason to not select the source at the source selection step."[21] EPA goes on to extend this deadline by adding an indeterminate grace period: "The year 2028 is not a bright line for these considerations, so a state may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028."[22] EPA further advises states that consideration of source retirement and replacement schedules required by Section 51.308(f)(2)(iv)(C) are automatically considered if a state decides to not subject sources which will retire by 2028 to a four-factor analysis.[23]

This is a departure from EPA's long-standing requirement in the regional haze program and is in conflict with basic requirements of the Regional Haze Rule. Remaining useful life is one of the four statutory factors that a state must consider when selecting the sources for which it will determine what control measures are necessary to make reasonable progress.[24]

The Clean Air Act does not define the phrase "remaining useful life." However, EPA, in regulations and guidance, has clarified the meaning of the phrase. EPA has consistently stated that the potential retirement of a facility can be used to shorten a source's remaining useful life only if the retirement is federally enforceable.[25] Thus, in order to affect the remaining useful life, a retirement commitment must be included in a pre-existing document that can be enforced in federal court, such as a consent decree entered by a federal court, or a state must incorporate the retirement date into its SIP. If a potential retirement is not federally enforceable, it cannot be relied upon to shorten the remaining useful life of a source.

EPA's 2007 Guidance on reasonable progress incorporates and refers to the best available retrofit technology ("BART") Guidelines,[26] which instruct states on how to calculate the remaining useful life of a source. EPA defines a source's "remaining useful life" as the difference between the date that controls would be installed and "the date the facility permanently stops

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[21] Final Guidance at 20.
[22] *Id.*
[23] *Id.* at 22.
[24] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("[A]n agency rule would be arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem."); *Pub. Citizen v. Fed. Motor Carrier Safety Admin.*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) ("A statutorily mandated factor, by definition, is an important aspect of any issue before an administrative agency, as it is for Congress in the first instance to define the appropriate scope of an agency's mission.").
[25] *E.g.*, 83 Fed. Reg. 62,204, 62,232 (Nov. 30, 2018) ( "We are proposing to agree with Arkansas' cost analysis for dry scrubbers and switching to low sulfur coal for Independence Units 1 and 2, and with the state's decision to assume a 30-year capital cost recovery period in the cost analysis. It is appropriate to assume a 30-year capital cost recovery period in the cost analysis since Entergy's plans to cease coal combustion at the Independence facility are not state or federally-enforceable."); 83 Fed. Reg. 43,586, 43,604 (Aug. 27, 2018) (Considering the retirement of certain units where there was evidence that the units had actually been retired at the time of the rulemaking and that the plant had requested cancellation of its air permit).
[26] RPGs Guidance at 5-3. There is no conflict with the 2007 Guidance's interpretation of "remaining useful life" and the Final Guidance. *See* Final Guidance at 34.

operations."[27] If the remaining useful life affects the selection of controls, "this date should be assured by a federally- or State-enforceable restriction preventing further operation."[28] EPA discusses a situation where a source "intends to shut down a source by a given date, but wishes to retain the flexibility to continue operating beyond that date in the event."[29] In that instance, EPA instructs a state to include in its SIP the controls that would be required if the source continues to operate past the planned retirement date.[30] "The source would not be allowed to operate after the 5–year mark without such controls."[31]

Allowing states to avoid a four-factor analysis based on alleged intent to retire would render the other statutory factors meaningless and violate the requirements of the Regional Haze Rule.[32] Many states have already begun analyzing their sources to determine which should be brought forward for a four-factor analysis. Consequently, a source that retires by December 31, 2028 (or later), has at least eight years of potential emission reductions. Even considering this shortened remaining useful life, cost-effective controls, which often can be installed in months, can frequently be justified. For instance, a source could simply switch to a lower sulfur content coal or fuel oil, which would require little to no installation time and may be quite cost-effective. Despite EPA's advice, any source that demonstrably or potentially impacts visibility at a Class I area and would otherwise be subject to a four-factor analysis under section 51.308(f)(2)(i), regardless of its retirement date, must undergo a real analysis to determine if cost-effective controls are available.[33] EPA should revise the Final Guidance to reiterate that only enforceable retirements may alter the remaining useful life and otherwise require that states subject sources that intend to retire to a four-factor analysis if a state selects the source for analysis of emission control measures.

D. States cannot consider being under the URP when selecting sources for a four-factor analysis.

In Section II.B.3.e of the Final Guidance, EPA makes two flawed statements regarding a state's RPG that were not present in the Draft Guidance. First, EPA states "[t]he fact that visibility conditions in 2028 will be on or below the URP glidepath is not a sufficient basis by itself for a state to select no sources for analysis of control measures; however, the state may

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[27] 40 C.F.R. pt. 51, App. Y § (IV)(D)(4)(k)(2).
[28] *Id.*
[29] *Id.* § (IV)(D)(4)(k)(3).
[30] *Id.*
[31] *Id.*
[32] The United States Court of Appeals for the Fifth Circuit recently found that EPA must consider statutory factors listed in a similar provision of the Clean Water Act when revising best available technology ("BAT") limits. *See Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999, 1026-27 (5th Cir. 2019).
[33] EPA's draft guidance also allowed for states to forgo a four-factor analysis on sources secured by an enforceable commitment to retire by 2028. We disagree with that position for the reason expressed above. However, EPA tempered its reasoning in its draft guidance by stating that its position rested on the fact that due to the shortened second planning period (unlike future planning periods), there would be a shorter interval for states to install controls. Also, EPA did not state that states could extend source retirements beyond 2028 as it does in the final guidance.

consider this information when selecting sources."[34] EPA then cites to the 2017 Regional Haze Rule revisions; however, those citations make it absolutely clear that states cannot in fact follow this guidance:

> We disagree that the states should be able to reevaluate whether a control measure is necessary to make reasonable progress based on the RPGs. The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures already determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. [35]

Consequently, states have no path available to them to "consider this information when selecting sources."

Similarly, EPA's later advice that "[r]ather, that fact [that a state's RPG is below the URP] would serve to demonstrate that, after a state has gone through its source selection and control measure analysis, it has no 'robust demonstration' obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B)"[36] is potentially at odds with the Regional Haze Rule. In the above cited portion of the 2017 Regional Haze Rule revision, EPA actually stated, "if a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line."[37] A state's "robust demonstration" obligation does not end because it has merely "gone through its source selection and control measure analysis." Rather, as EPA actually explained, the state must have "reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress." [38] EPA must reconsider this provision, and delete it from the Final Guidance.

E. Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.

In section II.B.3.f of the Final Guidance, EPA discusses circumstances under which a state can choose not to select a source that has previously installed controls for a four-factor analysis.[39] Much of this information conflicts with previous guidance and the Regional Haze

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[34] Final Guidance at 22.
[35] 82 Fed. Reg. at 3093. *See also* 81 Fed. Reg. at 66,631; 81 Fed. Reg. at 326; RPGs Guidance at 4-1.
[36] Final Guidance at 22.
[37] 82 Fed. Reg. at 3093.
[38] *Id.*
[39] *Id.* In comparison to the blanket exemptions in EPA's Final Guidance, the Draft Guidance only considered exempting power plant units, "in certain limited situations," with "highly effective control technology within the 5 years prior to submission of the SIP, such as year-round operation of flue gas desulfurization (FGD) with an

Rule. First, EPA states, "[i]n general, if post-combustion controls were selected and installed fairly recently . . . to meet a [Clean Air Act] requirement, there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions having been made in the intervening period."[40] EPA presents no basis for making this conclusion.

There are many instances in which post-combustion controls have been installed in which those controls do not operate at peak efficiency. This includes controls that are not operated continuously, controls that were never designed to operate at peak efficiency (e.g., undersized sulfur dioxide ("$SO_2$") scrubber or selective catalytic reduction ("SCR") systems) and partially bypassed controls (e.g., $SO_2$ scrubber or SCR systems). In fact, EPA has made it a point in past actions to ensure that existing controls are examined to determine if they can be cost-effectively upgraded. For instance, the 2005 BART revision to the Regional Haze Rule devotes several paragraphs to specific potential scrubber upgrades it recommends be examined.[41]

EPA also demonstrated that scrubber upgrades to a number of coal-fired power plants utilizing outdated and inefficient scrubber systems were highly cost-effective, and could achieve removal efficiencies of ninety-five percent which is near the ninety-eight to ninety-nine percent removal efficiencies of newly-installed scrubber systems.[42] In fact, as EPA notes in its 2017 Regional Haze Rule revision, EPA disapproved Texas' four-factor analysis in part because "it did not include scrubber upgrades that would achieve highly cost-effective emission reductions that would lead to significant visibility improvements."[43] Consequently, EPA's blanket guidance that examination of potential upgrades to recently installed post-combustion controls is unlikely necessary is demonstrably false. Even if, considering the entire universe of potential post-combustion control upgrades, the vast majority cannot be cost-effectively upgraded to result in significant visibility benefits, which is unlikely, there is no justification in the Regional Haze Rule to skip an examination of the remaining units.

EPA goes on to present examples of pollutant-specific controls that have been installed due to a requirement outside of the regional haze program for which it "believes it may be reasonable for a state not to select a particular source for further analysis."[44] This list includes new source performance standard ("NSPS") controls installed since July 31, 2013; best available control technology ("BACT") or lowest achievable emission rate ("LAER") controls installed since July 31, 2013; power plants with FGD controls that meet the 2012 model attainment test systems ("MATS") standard; particulate matter ("PM") controls under National Emission

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effectiveness of at least 90 percent or year-round operation of selective catalytic reduction with an effectiveness of at least 90 percent." EPA specifically requested comment "on whether to include this additional screening mechanism and if so, then what criteria may be appropriate for its inclusion."

[40] *Id.*

[41] *See* 70 Fed. Reg. 39,103, 39,171 (July 6, 2005).

[42] *See* 81 Fed. Reg. at 305.

[43] *See* 82 Fed. Reg. at 3088.

[44] Final Guidance at 23.

Standards for Hazardous Air Pollutants ("NESHAP") since July 31, 2013; boilers that have installed an FGD or SCR system that operates year round and has a total efficiency of ninety percent; and any BART-eligible unit that has installed BART controls.[45] EPA reasons that due to their recent installation and the similarity of the requirements for those programs, it is unlikely that a four-factor analysis will result in additional cost-effective controls.[46] But, as EPA notes in its 2005 BART revision to the Regional Haze Rule, it reviewed some of these standards and concluded they may not be the most stringent available.[47] Furthermore, the 2017 revision to the Regional Haze Rule warned states that "we anticipate that a number of BART-eligible sources that installed only moderately effective controls (or no controls at all) *will need to be reassessed*. Under the 1999 [Regional Haze Rule and] 40 CFR 51.308(e)(5), BART-eligible sources are subject to the requirements of 40 CFR 51.308(d), which addresses regional haze SIP requirements for the first implementation period, in the same manner as other sources going forward."[48] This is in contrast to EPA's Final Guidance statement that "if a source installed and is currently operating controls to meet BART emission limits, it may be unlikely that there will be further available reasonable controls for such sources."[49] Therefore, a state must first subject a source to a four-factor analysis under section 51.308(f)(2)(i) before it is able to determine whether there are no emission reducing options available (including upgrades to existing controls).

Regarding which control measures states should consider in assessing reasonable progress, EPA states "there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."[50] This conflicts with past guidance and with the Regional Haze Rule. Although there is no requirement that controls required under the reasonable progress requirements of the Regional Haze Rule uniformly be the most stringent available, not considering this level of control bypasses section 51.308(f)(2)(i), which requires that the state perform a four-factor analysis. A state cannot consider "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" unless it considers all feasible controls available, including upgrades to existing controls.

EPA acknowledged that a range of controls should be evaluated in a four-factor analysis in its Draft Guidance:

> In order to define a control measure with sufficient specificity to assess its cost and potential for emission reductions, the state should specify and consider the range of control efficiencies that the measure is capable of achieving. For example, when

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[45] *Id.* at 23-25.
[46] *Id.* at 25.
[47] *See* 70 Fed. Reg. at 39,163-64.
[48] 82 Fed. Reg. at 3083 (emphasis added).
[49] Final Guidance at 25.
[50] *Id.* at 29.

> evaluating a flue gas desulfurization system to reduce $SO_2$ emissions, the state should consider both a system capable of achieving a 90 percent reduction in $SO_2$ emissions as well as a more advanced system capable of achieving a 97 or 98 percent reduction. The state should not limit its analysis to either an unrealistically high and prohibitively expensive control efficiency or to a control efficiency that is substantially lower than has been achieved at other sources.[51]

Furthermore, EPA does not require that states secure the operation of controls with this level of efficiency through an enforceable commitment.

Just because a source has the most effective or highly effective control technology does not mean that it is required to be operated to a level reflective of its maximum pollution reduction capability. Thus, states should not be screening such sources out of review during the second implementation period. By allowing states to "screen out" and choose not to select such sources for a full four-factor analysis, EPA may be allowing states to ignore very cost-effective emission reducing options like simply requiring sources with highly effective controls to operate those controls in the most effective manner to reduce air pollutants. EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, reducing capacity, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, or requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

F. States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.

EPA should revise the Final Guidance to recommend that wherever possible, whether they are screened in or out, states should make sure that the emissions relied upon in the state's RPG demonstration are enforceable, and also that they reflect the lowest emission rates feasible at the facility given its existing configuration. This is particularly true for major sources that are screened out on the basis of emissions that reflect unenforceable conditions.

However, this is also true for sources that are screened out on the basis of emissions that do not reflect their full capacity for emission reductions. For example, if a source is screened out with emissions that reflect using its controls only seventy-five percent of the time, the state should nevertheless require year-round operation of the control. Requirements reflecting existing capacity for emission reductions are inherently reasonable, and represent low hanging fruit necessitating reduced resource expenditure for potentially large gain. Moreover, states routinely rely on actual emissions in assessing current visibility and using that assessment as a jumping off point to determine if additional reductions are necessary. Where a state is to rely on operational

[51] Draft Guidance at 87.

realities, such reliance must be justified by enforceable emission limits. Indeed, failing to take advantage of such reasonable progress measures is an example of one of the pitfalls of using this type of a screening process in the first place. EPA should recommend that states assure reasonable progress by requiring that sources have enforceable limits or conditions reflecting their full emission reduction capacity if they are to be screened out.

G. States must include both "dominant" and "non-dominant" pollutants in their analyses of controls.

In Section II.B.3.a of the Final Guidance, EPA advises states that they can skip analyses of controls for sources with "non-dominant" pollutants. Specifically, EPA states:

> When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors. Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants.[52]

This position, absent from the Draft Guidance, directs states to produce deficient regional haze SIPs and is in conflict with the Regional Haze Rule's requirements and preamble language in the 2017 Regional Haze Rule revision.

The preamble specifically states that a "reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by . . . *failing to include cost-effective controls at sources with significant visibility impacts*, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP.[53] This provision in the Guidance would allow states to arbitrarily determine that because one pollutant has a greater impact on visibility at a Class I area(s), the state may simply ignore other visibility impacting pollutants for one or all sources in the state emitting the non-dominant pollutants, despite the availability of cost-effective controls under reasonable progress criteria. It would also allow states to conclude that when examining a source that emits multiple pollutants that contribute to haze (e.g., $SO_2$, Nitrogen Oxide ("NOx")), potential reductions for the non-dominant pollutant can be summarily ignored. Furthermore, EPA does not provide any metric for what it considers a "dominant" pollutant.[54] For instance, if a state has determined that fifty-one percent of the visibility impact at a Class I area is due to $SO_2$, forty

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[52] Final Guidance at 11.
[53] 82 Fed. Reg. at 3088. EPA states elsewhere in its 2017 Regional Haze Rule revision, that "A state may refer to its own experience, past EPA actions, the preamble to this rule as proposed and this final rule preamble, and existing guidance documents for direction on what constitutes a reasoned determination." 82 Fed. Reg. at 3099.
[54] Merriam-Webster defines dominant as "(a) commanding, controlling, or prevailing over all others," or as "(b) very important, powerful, or successful."

percent is due to NOx, and nine percent is due to PM, would $SO_2$ be considered dominant (and consequently the only analyzed pollutant), or must its share of the visibility impact be greater?

This provision in the Final Guidance has potentially far-reaching negative impacts on the Regional Haze Rule's requirements that states make reasonable progress, as many large sources emit multiple types of visibility impacting pollutants. Still other sources may emit significant levels of non-dominant emissions for which emission reducing control or measures may be well within the framework of the four-factor analysis. If this is not corrected, a state could assume it would be justified in concluding that state-wide, $SO_2$ is its "dominant" pollutant and forego control analysis of a large gas-fired power plant emitting thousands of tons of NOx which could also significantly impact visibility at one or more Class I areas.

The Final Guidance also directly conflicts with multiple sections of the Regional Haze Rule. For instance, a state following the guidance would not be able to determine if it was even subject to section 51.308(f)(3)(ii)(B), because by arbitrarily excluding pollutants or entire sources from review it could not determine if it "reasonably [was] anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State." Nor could that state "demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Similarly, if that state's RPG was above its URP, it could not satisfy section 51.308(f)(3)(ii)(A), which requires the same demonstration. Such a state would also not be able to reasonably satisfy its state-to-state consultation requirements under section 51.308(f)(2)(i), which requires it to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress" and "include 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." By severely compromising the entire foundation of a state's technical demonstration, EPA is directing states to submit deficient SIPs. For these reasons, EPA should delete the above-quoted language from the Final Guidance.

H. States cannot eliminate VOCs and ammonia emissions from consideration.

In Section II.B.3.a. of the Final Guidance, EPA also advises states that irrespective of their particular state emissions inventories or the acknowledged potential impacts of VOCs and ammonia on Class I areas, they can completely disregard these pollutants. Specifically, EPA states:

> In the first implementation period, many states eliminated VOC and ammonia emissions from consideration based on the expectation that anthropogenic VOC emissions make only a small contribution to visibility impairment and that formation of nitrate and sulfate PM is most effectively reduced by reducing emissions of NOx and $SO_2$ rather than by anthropogenic emissions of ammonia. EPA believes that, in general, this

> would also be a reasonable approach for the second implementation period.[55]

This position is completely absent from EPA's regulations and was not present in the Draft Guidance.

VOCs are organic chemicals emitted by products or industrial processes that when released into the atmosphere can react with sunlight and NOx to form tropospheric ("ground-level") ozone. In addition, VOCs are important precursor of Secondary Aerosol Formation ("SOA"). SOA comprises a large fraction of atmospheric aerosol mass and can have significant effects on atmospheric chemistry, visibility, human health, and climate.[56] A major source of VOCs in the United States is the oil and gas industry, which includes wells, gas gatherings and processing facilities, storage, and transmission and distribution pipelines. According to data from EPA and the Energy Information Agency ("EIA"), more than 20 million tons of VOCs are emitted from point and non-point sources in the oil and gas industry every year. Studies on oil and gas emissions have indicated that VOC source signatures associated with oil and gas operations can be clearly differentiated from urban sources dominated by vehicular exhaust emissions.[57][58] According to a recent air quality study by the National Park Service ("NPS") in Carlsbad Caverns National Park, high levels of light alkanes such as ethane, propane, butane, and, pentane compounds were consistent with oil and gas emissions. However, high alkanes ("$>C_8$") and aromatics are assumed to contribute more significantly to SOA formation.[59]

In California alone, statewide agricultural operations produce an average of 272.12 tons per day ("tpd") of ammonia ("$NH_3$") emissions.[60] Of those 272.12 tpd, 158.50 tpd is attributed to "agricultural waste" specifically from dairy cattle.[61] In regions such as California's heavily polluted San Joaquin Valley, ammonia concentrations are found to be much higher than NOx

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55 Final Guidance at 12.
56 Ziemann, Paul J., & R. Atkinson, *Kinetics, products, and mechanisms of secondary organic aerosol formation*, 41, no. 19 Chem. Soc'y Reviews 6582, 6582 (2012).
57 *See* Odum J.R., T. Hoffmann, F. Bowman, D. Collins, R.C. Flagan, & J.H. Seinfeld, *Gas/Particle Partitioning and Secondary Organic Aerosol Yields*, 30 Environ. Sci. Technol., 2580, 2580-2585 (1996).
58 *See* Swarthout, R. F., Russo, R. S., Zhou, Y., Hart, A. H., and Sive, B. C., *Volatile organic compound distributions during the NACHTT campaign at the Boulder Atmospheric Observatory: Influence of urban and natural gas sources*, J. Geophys. Res. Atmos., 118, 10,614–10,637, (2013), *available at* https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/jgrd.50722.
59 Ziemann, *supra* note 56, at 6583; *see also* Takekawa, Hideto, Hiroaki Minoura, and Satoshi Yamazaki, *Temperature dependence of secondary organic aerosol formation by photo-oxidation of hydrocarbons*, Atmospheric Environment 37, no. 24, 3413-3424 (2003).
60 California Air Resources Board, 2016 SIP Emission Almanac Projection Data by EIC: Annual Average Emissions (Tons/Day) Statewide, Miscellaneous Processes 620-Farming Operations, https://www.arb.ca.gov/app/emsinv/2017/emseic_query.php?F_YR=2012&F_DIV=-4&F_SEASON=A&SP=SIP105ADJ&SPN=SIP105ADJ&F_AREA=CA&F_EICSUM=620.
61 *Id.*

concentrations.[62] When mixed with the region's NOx emissions (primarily from mobile sources), this excess ammonia helps form high levels of haze causing ammonium nitrate, which accounts for the majority of PM2.5 emissions found in the San Joaquin Valley.[63]

The San Joaquin Valley is home to multiple communities such as Bakersfield, Fresno, and Visalia that rank amongst the very topmost polluted cities for both annual and twenty-four hour PM2.5 pollution. [64] The entire air basin is also listed as being in extreme nonattainment with the 1997 and 2006 PM2.5 NAAQS standards.[65] As it relates to regional haze pollution, the San Joaquin Valley is located directly adjacent to the Southern Sierra Nevada Mountains, home to heavily polluted Class 1 areas like Sequoia and Kings Canyon National Parks—both of which fall within the jurisdiction of the San Joaquin Valley Air District.

Despite ammonia being a major precursor to PM2.5 pollution in the region, its emissions are currently not controlled in the San Joaquin Valley under the state's various PM2.5 SIPs.[66] Beyond ammonia, agricultural sources in California also produce and average of 145.90 tpd of direct PM10 and 21.79 tpd of direct PM2.5 emissions.[67]

In its 2005 BART amendments to the Regional Haze Rule, EPA left it to the states to individually determine if these two pollutants, which EPA acknowledges can potentially impact visibility, should be addressed.[68] In the Draft Guidance, EPA acknowledged that much of its guidance on BART remained applicable to the second round of SIPs and included an entire appendix devoted to identifying which portions of the BART guidance remained applicable.[69] This appendix has been deleted in EPA's Final Guidance. By arbitrarily excluding potential visibility-impairing pollutants from review, EPA's guidance conflicts with the same sections of the Regional Haze Rule as described *supra* section III.G, primarily preamble language to the 2017 Regional Haze Rule revision and sections 51.308((f)(3)(ii)(A), 51.308((f)(3)(ii)(B), and 51.308(f)(2)(i). EPA should revise the Final Guidance to direct states to inventory and evaluate potential visibility-impairing pollutants including VOCs and ammonia and determine associated control measures necessary to make reasonable progress. .

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[62] San Joaquin Valley Air Pollution Control District, 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards, at 5-6, http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.
[63] *Id.* at 3-12.
[64] American Lung Association, 2019 State of the Air Report: Most Polluted Cities Ranking, https://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/most-polluted-cities.html.
[65] San Joaquin Valley Air Pollution Control District, *supra* note 62, at ES-8.
[66] *See generally, id.* at 4-1 through 4-34.
[67] *See* California Air Resources Board, *supra* note 60.
[68] *See* 70 Fed. Reg. 39,104, 39,112-14 (July 6, 2005). EPA stated that scientific and technical data shows "that ammonia in the atmosphere can be a precursor to the formation of particles such as ammonium sulfate and ammonium nitrate . . . [and] certain aromatic VOC emissions such as toluene, xylene, and trimethyl-benzene are precursors to the formation of secondary organic aerosol." *Id.* at 39,114.
[69] Draft Guidance at Appendix D.

I. Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.

States choosing light extinction as a metric for visibility impacts should use Class I-specific figures to identify sources for a four-factor analysis. If a threshold is applied, states must ensure that the threshold is low enough to bring in most sources harming a Class I area. In the Final Guidance, EPA recommends visibility metrics and thresholds in terms of inverse megameters of light extinction.[70] Although light extinction may be acceptable as a metric, states should not use a generic extinction threshold for selecting sources for consideration of pollution controls for each of the Class I areas evaluated in their regional haze SIPs. If a light extinction threshold is too high, it can significantly limit the amount of sources a state evaluates for controls to make reasonable progress.

States must make clear how each source's visibility impacts are to be determined. States must explain whether the sources' potential emissions were modeled, what visibility-impairing pollutants were modeled for each source, whether all units were modeled for all sources, whether sources were modeled for impacts on the twenty percent worst days or some other timeframe, and identify and allow public review of and comment on the technical approach that the state employed to determine source-specific visibility extinction, pursuant to 40 C.F.R. § 51.308(f)(2). Any proposed extinction threshold for defining sources to target for controls is only as good as the underlying technical analysis to define if a source exceeds the extinction threshold. States must address these requirements and justify any and all extinction thresholds that they rely on for each Class I area impacted by states' sources.

For any souces that exceed an extinction threshold but are not subject to reduction requirements, states should provide a thorough four-factor analysis of controls or provide justification as to why a four-factor analysis would not likely lead to a determination that additional controls are needed to make reasonable progress. For any sources that a state claims already has adequate controls or justifies for other reasons that a four-factor analysis of controls would not result in additional controls, the state must document in its regional haze SIP why it makes this finding. To the extent such justification is relying on other regulatory or permit requirements, the state must document those regulatory or permit requirements in detail and indicate whether such requirements are already or will be submitted to EPA as part of the SIP

J. State's using the Q/d metric should include all visibility-impairing pollutants when calculating a source's annual emissions.

In Section II.B.3.b of the Final Guidance, EPA discusses the use of a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts, along with a reasonably selected threshold for this metric.[71] As EPA notes, although Q/d is the least

[70] Final Guidance at 19.
[71] Final Guidance at 13.

complicated technique, it should "be limited to source selection for the purpose of developing a list of sources for which a state may conduct a four-factor analysis" because the metric is a less reliable indicator of actual visibility impact.[72]

EPA should revise the Final Guidance to require states using the Q/d metric to include all visibility-impairing pollutants when determining the annual emissions being used to obtain a source or source category's estimated visibility impacts. As discussed further *supra* section III.H, states cannot eliminate certain emissions, such as VOCs and ammonia emissions, from consideration. Additionally, EPA should recommend that states using the Q/d metric not use the Q/d threshold from the first implementation period for the second implementation period. Rather, the Q/d threshold should be lower in order to address more sources, including sources that are lower emitting and sources that are further in distance than the sources addressed in the first implementation period.

## IV. Determination of affected Class I areas in other states

### A. States must use methods permitted by statute and regulation to identify its sources that impact visibility at Class I areas in other states, not merely any "reasonable method."

In Section II.B.2 of the Final Guidance, EPA inserts a blanket statement that jeopardizes making progress towards the Clean Air Act Class I visibility goal and obfuscates the Regional Haze Rule's requirements regarding how a state should identify its sources that impact the visibility at Class I areas in other states: "As an initial matter, a state has the flexibility to use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas, and it may use any reasonable assessment for this determination."[73]

EPA does not provide any explanation or examples of what it considers "reasonable." Thus, this statement would allow a state to use any methodology, regardless of its scientific rigor, to identify those sources. Furthermore, once having identified these sources, however loosely, the state can then "assess" those sources any way it wishes. Confusingly, EPA seems to distinguish between quantifying the impacts of these sources and assessing these impacts. This single statement would serve to hand a state seemingly unlimited discretion over a key step in preparing its SIP, in marked contrast to what it proposed.

As EPA states in its 2017 Regional Haze Rule revision:

> On July 8, 2016, we released Draft Guidance that discusses how states can determine which Class I areas they ''may affect'' and therefore must consider when selecting sources for inclusion in a four-factor analysis. The Draft Guidance discusses various approaches that states used during the first implementation

[72] *Id.*
[73] Final Guidance at 8.

> period, provides states with the flexibility to choose from among these approaches in the second implementation period, and recommends that states adopt ‘‘a conservative . . . approach to determining whether their sources may affect visibility at out-of-state Class I areas.[74]

Indeed, EPA's Draft Guidance did provide actual guidance to the states on this issue:

> Once contributions by sources, groups of sources or geographic areas have been quantified in some manner, the EPA recommends that states adopt a conservative (more protective approach of visibility) approach to determining whether their sources may affect visibility at out-of-state Class I areas. For example, states could consider all Class I areas for which the state contributes at least one percent to anthropogenic light extinction from all U.S. sources on any day within the 20 percent most impaired days. States may choose a different threshold to determine which out-of-state Class I areas may be affected by the States sources, but must provide an adequate explanation of why the threshold is sufficiently protective of visibility.[75]

EPA followed this statement with more than twelve pages of highly technical guidance detailing approaches it deemed acceptable.[76] The Final Guidance deletes most of this and provides a summary approach void of technical rigor or analytical teeth. The Regional Haze Rule makes plain that a state's long-term strategy, including its application of the four statutory factors, be comprised of a robust initial step—the assessment of the state's emission sources on downwind states' Class I areas. However, by diminishing actual guidance and inventing this undefined and ambiguous standard, EPA creates confusion and ambiguity for states, leaving states to determine reasonability on a SIP-by-SIP basis. EPA should restore the discussion and directives to states from the Draft Guidance.

B. Application of a threshold for cumulative impacts to multiple Class I areas.

EPA should reconsider and revise the Final Guidance to recommend that states quantitatively document the results of the screening process for each Class I area rather than presenting only the impacts at the most affected or nearest Class I area. This allows the public to know the scope of the source's impacts and assures that the SIP comports with the letter and spirit of the regional haze program, a program grounded in the fact that regional haze is a regional problem and that Class I area impacts are felt typically by a multitude of sources' pollution that defy state boundaries.

EPA should also make clear that states must consider cumulative impacts of sources or groups of sources to all affected Class I areas. A source's cumulative impacts across Class I

[74] 82 Fed. Reg. at 3094.
[75] Draft Guidance at 58.
[76] Draft Guidance at 58-70.

areas provides a valuable screen to identify sources for further analysis. As EPA conceded and the court found in *Nat'l Parks Conservation Ass'n v. EPA*, in considering the visibility improvement expected from the use of controls, states must take into account the visibility impacts at all impacted Class I areas rather than focusing solely on the benefits at the most impacted areas.[77] This must include sources that have relatively small impacts in isolation but larger cumulative impacts either in the aggregate or across Class I areas.

V. Ambient data analysis

A. States must prioritize emissions within their borders to achieve reasonable progress.

International emissions contribute to visibility impacts. Rather than encouraging states to pursue an adjustment to the end goal of natural visiblity due to international emissions, EPA should be directing states to focus on the emissions within their borders for which requirements would help achieve reasonable progress. We encourage EPA to work with states, FLMs, stakeholders, and other countries to develop emissions inventories for cross-border pollution as well as scientifically valid methods for assessing long range emissions transport. However, the development of accurate accounting and modeling should not come with the expense of postponing or ignoring domestic emission-reducing measures. EPA's updated 2028 modeling[78] attempts to incorporate international emissions, but the agency itself makes clear that the science upon which the modeling rests is questionable.[79] EPA should reconsider and revise its Guidance to clarify that assessing international emissions is a work in progress and opportunity for partnership across a broad set of stakeholders, but the mandate of the Clean Air Act compels states to take measures to make reasonable progress by reducing emissions in their borders, not look to analysis to excuse doing so because other nations also contribute to regional haze.

We also urge EPA to revise the Final Guidance to clarify that affected states also have an obligation to take appropriate action to address international emissions.[80] Although EPA and the states are not required to "compensate" for international emissions, it is well within EPA and the states' rights and obligations to formally request reductions from international sources where appropriate, or to take permitting actions in the United States that will lead to emission reductions in other countries.

For example, Mexico's Carbon I and II power plants, which are less than twenty miles from the Texas border, are responsible for significant levels of pollution across several of the border states. Despite noting the significant impact of Mexican sources on its Class I areas, and

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[77] *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 165 (3d Cir. 2015).
[78] EPA, Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling (Sept. 19, 2019), https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf ("Updated 2028 Modeling").
[79] *Id.* at 67.
[80] 64 Fed. Reg. 35,714, 35,755 (July 1, 1999) ("The States retain a duty to work with EPA in helping the Federal government use appropriate means to address international pollution transport concerns.").

requesting federal efforts to reduce impacts from international emissions,[81] Texas approved water discharge and mining permits for a coal mine in Maverick County. Rejecting these permits instead would have prevented the Mexican company Dos Republicas from mining high-sulfur coal that is transported and burned at the Carbon I & II facilities. EPA should remove its false implication that international emissions are entirely "uncontrollable" and should instead make clear that states must demonstrate that they are doing what is within their control to address international emissions—both generally and in particular.

EPA also discusses an "adjustment" to the URP for prescribed wildland fires. Wildfires, particularly in the West, have grown hotter, bigger, and more frequent with climate change. We recognize the role of prescribed fire in both managing fire size due to climate impacts and in restoration of natural ecosystems—which can, if effective, reduce the size and scale of fires later. There are, as a result of increased prescribed fire, potential benefits to both short- and long-term air quality. In planning for prescribed wildland fires, states should consider effects on visibility, alongside health and other concerns, including potential control measures and the potential benefits. A State cannot adjust a URP based on prescribed fires unless these fires actually result in visbility impairment on the "most-impaired" days. The Final Guidance should be clear that analysis of and planning for prescribed wildland fires need to be tailored to the planning period basis and would not automatically apply to the next planning period.

VI. Characterization of factors for emission control measures

A. States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

In Section II.B.4.a of the Final Guidance, EPA advises states that they have the flexibility to reasonably determine which control measures to evaluate, and the agency lists examples of types of emission control measures states may consider.[82] EPA should reconsider its approach to ensure that the best controls for a source or source category are identified, evaluated, and the appropriate option determined. Identification of all available control measures is an important first step to ensure the best controls or emission reduction measures emerge from a four-factor analysis. However, EPA should revise the Final Guidance to ensure evaluation of the best control options.

1. EPA should reiterate and expand upon Step 1 of the BART-Guidelines regarding the identification of all available emission control techniques.

EPA should encourage states to consider various sources of information and types of emissions control techniques in developing its long-term strategy. Specifically, EPA should make clear that states must look to new source review control technology determinations, including major source BACT and LAER determinations, as well as state minor source BACT

[81] Texas Revisions to the State Implementation Plan (SIP) Concerning Regional Haze, at ES-2 (Feb. 25, 2009).
[82] Final Guidance at 29-30.

determinations. EPA should also recommend that states evaluate technologies that were considered in applicable new source performance standards, as well as those emission controls that were required in applicable new source performance standards.[83] EPA should also recommend that states consider the control techniques evaluated and required for similar source BART determinations.

In addition, EPA should recommend that states consider BACT determinations and other new source control requirements that states have adopted in minor new source review permits. Several states have minor source BACT provisions which may provide useful information for control technology considerations, and/or states have adopted targeted emission control requirements for source categories that do not have parallel federal requirements.[84]

Further, EPA should recommend that states investigate controls for source categories evaluated in reasonably available control measures ("RACM")/ reasonably available control technology ("RACT") and best available control measures ("BACM")/BACT determinations for nonattainment areas, a good starting point for information for control techniques available for a particular source category. States should also be encouraged to consult vendors or vendor groups such as the Institute of Clean Air Companies for control techniques for sources or source categories.

States should consider inherently lower-emitting processes, by themselves, and in combination with add-on controls. A state should not reject a combination of control measures altogether when the control measures could also be applied independently, unless the state is instead focusing on a control measure that is more effective at reducing emissions than the individual control measures.

In general, EPA should provide flexibility for states to consider innovative technologies tied to quantifiable and enforceable emission reduction requirements and to consider control techniques that some could view as "redefining the source" such as a change in fuel form. The BART Guidelines seemed to limit such controls from consideration for BART. Setting aside whether this was appropriate for BART determinations, States should not be constrained when evaluating measures to consider for the long-term strategy to make reasonable progress towards the national visibility goal.

In evaluating measures for the long-term strategy, states may need to address sources that were constructed many decades ago and/or sources to which pollution controls have not typically

[83] As EPA acknowledges in the BART guidelines, the NSPS standards do not always require the most stringent level of available control technology for a source category. 40 C.F.R. Part 51, Appendix Y, Section IV.D.2. In some cases, EPA evaluates more stringent controls in an NSPS proposed rulemaking, but ultimately requires a less stringent control to set the NSPS standard. EPA should make clear that NSPS standards are likely insufficient for purposes of reasonable progress determinations because the standards will not be reflective of the reduction measures available and otherwise meeting the four factors as SIPs are being advanced.

[84] *See, e.g.*, Colorado Regulation No. 7 – Control of Ozone via Ozone Precursors and Control of Hydrocarbon via Oil and Gas Emissions, https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=8546&fileName=5%20CCR%201001-9.

been applied. There may be little experience with applying pollution controls to such sources. However, the lack of information on "available" control technologies should not be used as a justification to eliminate a source from consideration of controls (or to only evaluate less effective controls). In such cases, States should be encouraged to consider innovative technologies, technologies that may not have historically been applied to the source type but could be transferred to the source type, emission unit replacement with more energy efficient/less polluting technology, and other such measures in evaluating how to best reduce haze-forming pollution from the source or source type.

2. EPA should advise states how to determine "available" and "technically feasible" control techniques for long-term strategy measures.

EPA should elaborate on how to determine whether a control technique is considered "available" or "technically feasible" for a source or source category. Section IV(D)(1) of the BART Guidelines[85] states in part that that "available retrofit control options are those with a practical potential for application to the emissions unit . . ." and "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice." EPA should recommend that states take a broader view in determining what control strategies are "available" for a source or source category, especially if traditional pollution controls had not been historically applied to that source category. In such cases, states may need to examine more innovative options for pollution control at such sources or source categories, including the consideration of promising pollution control options that have not already been demonstrated in practice but which offer quantifiable emission reductions.

Section IV(D)(1) of the BART Guidelines includes provisions to determine whether a control option is "technically feasible." Those provisions, as well as the discussion on available technologies, generally track guidance on evaluations for BACT determinations set out in EPA's New Source Review Workshop Manual.[86]

Sources often make availability or technical infeasibility arguments to avoid having to consider a pollution control, pointing out that that the control has not been used on the specific type of coal the source utilizes or on the particular size plant. Given that states may be having to determine controls for sources or source categories that have not been traditionally controlled in the long-term strategies, EPA should encourage states in such situations to fully evaluate controls that can be transferred from other source categories or that can be altered to accommodate the specific source or source category in question. EPA should recommend in such situations that states consult with, for example, environmental consultants, research technical journals, or air pollution control conference articles. States should also consider technologies demonstrated outside of the United States. EPA's New Source Review Workshop Manual describes how to

[85] 40 C.F.R. § Pt. 51, App. Y.
[86] U.S. EPA, New Source Review Workshop Manual, at B.17-B.21 (Draft Oct. 1990).

identify all control options "with potential application to the source and pollutant under evaluation."[87]

In summary, EPA should reconsider and revise the Final Guidance to elaborate on how states should evaluate available and technically feasible control techniques with the goal of ensuring that all potential controls with a practical application to a source or source category are considered in the development of the long-term strategy.

B. Cost analyses for the long-term strategy.

1. States must adhere to the accounting principles of the Control Cost Manual.

EPA should require states to follow the accounting principles and generic factors of EPA's Control Cost Manual because states and EPA have historically determined whether the costs of control measures are "reasonable" based on the costs that other similar sources determined in other regulatory actions including permits. [88] If EPA does not require all states to use the same accounting principles, it will be extremely difficult to compare costs of control between sources to evaluate whether the controls are cost effective.

2. States should compile and make publicly available the documentation for generic cost estimates.

EPA's Final Guidance suggests that states may reduce time and effort in determining control costs by using generic cost estimates or estimation algorithms, such as the Control Strategy Tool.[89] However, we request that EPA require the documentation for such generic cost estimates to be compiled and made publicly available. As stated in Sierra Club and National Parks Conservation Association's comments on EPA's proposed revisions to the Control Cost Manual, the Integrated Planning Model's SCR cost database is based on Sargent & Lundy's confidential database and the underlying data and methods used to develop the regression equations have not been publicly reviewed and analyzed.[90] Given that the cost estimates may be a primary basis for rejecting a control measure, the underlying data for such cost estimates must be publicly available.

C. EPA should reconsider and revise the Final Guidance regarding how to address energy and non-air quality environmental impacts of control measures.

EPA should state that the third factor of energy and non-air quality environmental impacts should generally be based on the same methodology laid out in the BART Guidelines. Section 8.1.1 of the BART Guidelines indicates that states must consider the energy and non-air quality environmental impacts as part of the cost analyses. With respect to taking into account non-air quality environmental impacts, we agree in general to take into account such impacts in

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[87] *Id.* at B.10-B.11.
[88] Final Guidance at 31.
[89] *Id.* at 32.
[90] *See* September 10, 2015 Comment Letter from Sierra Club and National Parks Conservation Association to U.S. EPA, Docket ID No. EPA-HQ-OAR-2015-0341, at 8.

the cost analysis if the costs can be quantified. Otherwise, such impacts may need to be discussed qualitatively and weighed in the four-factor analysis.

EPA should also revise the Final Guidance and recommend that states analyze the climate and environmental justice impacts of regional haze SIPs. Although the Regional Haze Rule does not define "non-air quality environmental impacts," the BART Guidelines, which inform a state's reasonable progress analysis, explain that the term should be interpreted broadly.[91] Climate change[92] and environmental justice[93] impacts are the types of non-air quality impacts that states should consider when they determine reasonable progress measures for specific sources. Incorporating climate change and environmental justice impacts into the regional haze analysis will further states' climate and environmental justice policy goals, and it will also help states ensure that their actions related to regional haze planning support their other work on climate and environmental justice issues. Most of the same sectors and sources implicated under the regional haze program are also implicated in climate and environmental justice initiatives. As a result, when states determine "the emissions reduction measures that are necessary to make reasonable progress," they should assess how those measures will either reduce or exacerbate greenhouse gas emissions and/or environmental justice impacts on nearby disproportionately burdened communities.

## VII. Decisions on what control measures are necessary to make reasonable progress

### A. States cannot allow sources to discontinue the use of currently operating controls.

In Section II.B.5.e of the Final Guidance, EPA advises states how currently controlled sources may be able to discontinue those controls under reasonable progress:

> It is also possible that a source may be operating an emission control device but could remain in compliance with applicable emission limits if it stopped operation of the device. The state may reasonably consider based on appropriate factors whether continued operation of that device is necessary to make reasonable progress, such that the regional haze SIP submission for the second implementation period must make such operation of the device (or attainment of an equivalent level of emission control) enforceable.[94]

Suggesting to states that they may discontinue the use of controls that are already operating is antithetical to the regional haze program. Rather, EPA should revise the Final Guidance to require states to evaluate more effective operation of existing controls, including year-round

[91] 40 C.F.R. pt. 51, App. Y at § (IV)(D)(4)(i), (IV)(D)(4)(j).
[92] *See, e.g.*, 74 Fed. Reg. 66,496 (Dec. 15, 2009) (EPA endangerment finding); Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2015), https://www.ipcc.ch/report/ar5/syr/.
[93] *See* EPA, Learn about Environmental Justice, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (last visited April 24, 2020); Exec. Order No. 12,898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 Fed. Reg. 7629 (Feb. 11, 1994).
[94] Final Guidance at 43.

operation requirements. Further, the Clean Air Act is clear that visibility is not a factor in determining reasonable progress measures required at a source.

In evaluating controls for a source that already had a control installed, such as a wet or dry scrubber for $SO_2$ or SCR or selective non-catalytic reduction ("SNCR") for NOx, states must be required to evaluate whether these controls can be more effectively operated. Companies tend to operate their air pollution control systems to the level needed to ensure compliance with applicable emission limits rather than to the maximum emission reduction capability of the pollution control technology. For example, there are electrical generating units ("EGUs") that are only operating their installed SCR or SNCR systems during the ozone season to meet limits under the Cross State Air Pollution Rule ("CSAPR"). Indeed, in projecting operations and emissions scenarios for evaluating the CSAPR program, EPA included assumptions for dispatchable SCR, SNCR, and also scrubbers, which reflected the fact that no emission limits or consent decrees required continuous operation of the pollution controls installed at many EGUs. EPA should thus recommend that states, at a minimum, require year-round operation of existing scrubbers, SCRs, SNCRs, or other controls as one of the control options considered.

Additionally, there are numerous examples of scrubbers, SCRs, and SNCRs that, when operated, are not operated to achieve the maximum emission reductions that could be accommodated within the existing control technology at a particular unit, primarily because the applicable emission limitation does not require operation of those pollution controls to achieve the maximum emission reductions. As mentioned *supra* section III.E, states should consider sources that already have in place the most stringent controls available for additional control in the development of the long-term strategy during the second implementation period.

EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, and requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

## VIII. Regional scale modeling of the long-term strategy to set the RPGs for 2028

### A. States should use regional scale modeling to support their regional haze SIPs.

In Section II.B.6 of the Final Guidance, EPA advises states that they are not required to use regional scale modeling to support their regional haze SIPs. Specifically, under Step 6, EPA states that a state must:

> Determine the visibility conditions in 2028 that will result from implementation of the LTS and other enforceable measures to set the RPGs for 2028. Typically, a state will do

> this through regional scale modeling, *although the Regional Haze Rule does not explicitly require regional scale modeling*.[95]

Were a state to forego estimating source or source categories emitting visibility-impairing pollutants, as the guidance provides, it would not be able to satisfy a number of basic requirements of the Regional Haze Rule. Estimating the visibility impacts from a collection of sources is a prerequisite of establishing a state's RPG. As EPA explains in its 2017 Regional Haze Rule revision, this is a key first step in a state setting its RPG: "the 2007 guidance clearly describes the goal-setting process as starting with the evaluation of control measures. First, we recommended that states '[i]dentify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area.'"[96] If a state did not estimate the visibility impacts from source or source categories, it could not satisfy the requirement in Section 51.308(f)(3)(ii)(A) that it demonstrate, "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Indeed, this misplaced advice is not even internally consistent with other sections of the Final Guidance, which cover many techniques for estimating the visibility impacts of sources or source categories. Estimating the collective visibility impacts of sources or source categories to determine the RPG is a fundamental requirement of the regional haze program.

In fact, there is no known substitute for the use of photochemical air quality models to project the visibility impact from thousands of individual sources, influenced by complex meteorological fields and atmospheric chemical interactions at a Class I area, ten years into the future, as EPA makes clear in Appendix W to Part 51.[97] The use of air quality models has been a cornerstone of the technical demonstration of the regional haze program (and many other air programs) since its inception. Almost every EPA Regional Haze Rule revision and guidance either discusses the use of air quality models or assumes their use. In fact, EPA recently updated its modeling guidance for regional haze.[98] The very first sentence of the section specifically devoted to regional haze is: "[t]his section focuses on the modeling analysis needed to set RPGs that reflect the enforceable emission limitations, compliance schedules, and other measures included in the long-term strategy of a regional haze SIP."[99] Part 51 makes it clear that air quality

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[95] Final Guidance, Table 1, at 6 (emphasis added).
[96] *See* 82 Fed. Reg. at 3092-93. Notably, EPA does not abandon its 2007 Guidance and in fact refers to in several places in its rule revision.
[97] *See* 40 C.F.R. Pt. 51; App. W, Section 2.0 (a), "Guideline on Air Quality Models," ("Increasing reliance has been placed on concentration estimates from air quality models as the primary basis for regulatory decisions concerning source permits and emission control requirements. In many situations, such as review of a proposed new source, no practical alternative exists."); *see also id.* at Section 1.0 (b), ("The impacts of new sources that do not yet exist, and modifications to existing sources that have yet to be implemented, can only be determined through modeling.") This is precisely the challenge of setting RPGs – accounting for modifications to potentially dozens of existing sources (e.g., installation of controls).
[98] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.s and Regional Haze, EPA 454/R-18-009, (Nov. 2018).
[99] *Id.* at 143.

modeling is a necessary tool in the setting of RPGs and EPA should not imply otherwise in its guidance.

Instead of guiding states on modeling, EPA repeatedly informs states that they can use "surrogates" to estimate visibility impacts of a body of sources. Specifically, EPA states that "the Regional Haze Rule does not require states to develop estimates of individual source or source category visibility impacts, or to use an air quality model to do so. Reasonable surrogate metrics of visibility impact may be used instead."[100] EPA lists a number of surrogates that can be used for this purpose, including Q/d, wind trajectories, and daily light extinctions budgets and states that states can use "other reasonable techniques."[101] However, although more strongly worded in its Draft Guidance,[102] EPA does state in its Final Guidance, "[s]urrogate metric here refers to a quantitative metric that is correlated to some degree with visibility impacts as they would be estimated via air quality modeling."[103] Consequently, although EPA tells states that modeling is unnecessary and that surrogate measures can be used, modeling is required in order to check the validity of visibility surrogates. EPA should reconsider this provision, and clarify that modeling is needed to assess the collective visibility impacts of sources or source categories to establish RPGs.

## IX. Progress, degradation, and URP glidepath checks

### A. If a state's RPG is above the URP, the state's "robust demonstration" must include a consideration of specific items identified by EPA.

In section II.B.7.c of the Final Guidance, EPA discusses what could constitute a "robust demonstration," required under section 51.308(f)(3)(ii)(A) when a state's RPG is above the URP.[104] EPA states that a simple "narrative explanation of how the state has already conducted the source selection and control measures analyses in such a manner that addresses the requirements of 51.308(f)(3)(ii)" may suffice.[105] EPA then goes on to note that such a state *may* consider a long list of additional items, including reconsideration of its visibility threshold, acceptable cost threshold, additional technically feasible controls, how its determination criteria compares to that of other states, etc.[106]

In contrast, EPA's Draft Guidance did not state that a simple narrative would suffice. The Draft Guidance stated that such a demonstration *should* include consideration of a similar listing

[100] Final Guidance at 12.
[101] *Id.* at 13.
[102] Draft Guidance at 76 ("Before relying on Q/d as a surrogate for screening purposes, a state should investigate how well Q/d relates to visibility impacts for the 20 percent most impaired and 20 percent clearest days, in terms of both the central tendency of the relationship (e.g., the regression line) and the variability of the relationship (e.g., the error of the regression). This understanding should be developed through relevant modeling of some actual cases or model plant scenarios, or another appropriate approach.")
[103] Final Guidance at 10 n.25.
[104] *Id.* at 50.
[105] *Id.*
[106] *Id.* at 50-51.

of items. EPA's pivot from *should* consider to *may* consider substantially misinterprets and is directly at odds with what the robust demonstration required under section 51.308(f)(3)(ii)(A) should contain.

Moreover, states should not rely on EPA's Updated 2028 Modeling[107] to determine which Class I areas are projected to be at or below the URP. Projected conditions for 2028 are tied to the 2064 natural conditions endpoint adjustments to account for international anthropogenic contributions, as well as wildfires. By EPA's own admission as discussed *supra* section V.A, these adjustments lack scientific validation and should not be relied on to determine whether a Class I area is on track to meet its URP in 2028.[108] The result of the updated modeling adjustments reduced the number of Interagency Monitoring of Protected Visual Environments ("IMPROVE") sites projected to be above the glidepath from forty-seven to eight. IMPROVE monitors are not the same as Class I areas, however many Class I areas share monitors; only ninety-nine monitoring sites (representing 142 Class I areas) were evaluated.[109] EPA must reconsider and revise the Final Guidance to specify what a "robust demonstration" under section 51.308(f)(3)(ii)(A) requires and that a state's demonstration should include consideration of the specific list of items identified by the agency.

## X. Additional requirements for regional haze SIPs

### A. States must submit to EPA the emission inventory used in a regional haze SIP.

In section II.B.8.c of the Final Guidance, regarding section 51.308(f)(6)(v) which covers the requirements for the state's emissions inventory, EPA states that "[t]he emission inventories themselves are not required SIP elements and so are not required to be submitted according [sic] the procedures for SIP revisions. The emission inventories themselves are not subject to EPA review."[110] This conflicts with the Regional Haze Rule, is internally inconsistent with the rule and other state requirements, and is impracticable. First, EPA's statement conflicts with several sections of the Regional Haze Rule. For instance, section 51.308(f)(2)(iii) requires that the state must document the following:

> [T]he 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 Federal area it affects. . . . The emissions information must include, but need not be limited to, information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to

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[107] *See* Updated 2028 Modeling.
[108] *Id.* at 67.
[109] *Id.* at 3 n.6.
[110] Final Guidance at 55.

> the Administrator in compliance with the triennial reporting requirements of subpart A of this part.

Here, it is clear that a state is required to document the technical basis of all aspects of its regional haze demonstration. A state's emission inventory is a foundational aspect of its technical demonstration. In fact, EPA specifically calls out "emissions information," and clarifies that the emissions information must include "information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to the Administrator."[111]

Plainly, a state is required to submit the emission inventory it is using as part of its technical demonstration to EPA, and that inventory must include certain specified elements. Because states are already required to submit specified emission inventories to EPA as part of other requirements ("Part A"), EPA clarifies that a state may refer to that submission instead of physically including it in its SIP. However, the mere fact that EPA specifies a state may use an already prepared work product does not shield it from a review of its suitability for the task at hand. [112] For instance, EPA has frequently stated that states may use the technical work of RPOs in their SIPs. That position has never been interpreted to mean information is shielded from EPA review.[113] Indeed, EPA has a duty to review that inventory in the context of the state's regional haze SIP submission.[114] Thus, a state's emission inventory is an inseverable part of its regional haze SIP and subject to EPA's review.

Despite this, EPA appears to imply in its guidance that it cannot bring to the state's attention potential faults in the emission inventory a state used to support its regional haze SIP, nor even examine that inventory in the context of its review of the state's regional haze SIP. EPA should revise the Final Guidance to advise states that a state's emission inventory is a part of the state's SIP and subject to EPA's review.

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[111] *Id.*

[112] *See* EPA's "Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations," EPA-454/B-17-002, at 11 (May 2017), ("[Inventory information provided to EPA] will allow the EPA to make a determination whether the emissions information used in Regional Haze analysis is sufficient for the purposes of the SIP.")

[113] For instance, in the Texas FIP, EPA observed that under the current regulation each state "must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving *reasonable progress* in each mandatory Class I Federal area it affects." 79 Fed. Reg. 74,818, 74,829 (Dec. 16, 2014) (emphasis in original). While the current regulations provide that, "[s]tates may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants," 40 C.F.R. § 51.308(d)(3)(iii), the Texas haze rule clarified that in situations "where a regional planning organization's analyses are limited, incomplete *or do not adequately assess the four factors*, however, then states must fill in any remaining gaps to meet this requirement." *Id.* (emphasis added).

[114] In the 2017 Regional Haze Rule revision, EPA makes it a point to review a number of circuit court opinions that affirm EPA's review authority, including the Eight Circuit's conclusion that EPA "must 'review the substantive content of the . . . determination." 82 Fed. Reg. at 3090 (quoting *Ariz. el rel. Darwin v. EPA*, 815 F.3d 519, 531 (9th Cir. 2016).

B. States must ensure that FLM opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP.

In Section II.B.8.a of the Final Guidance, EPA provides guidance to the states regarding the FLM consultation requirements in the Regional Haze Rule, 40 C.F.R. § 51.308. Although EPA reiterates that states are required to consult with FLMs, EPA should reconsider and revise the Final Guidance to ensure that states give credence to the opinions and concerns expressed by FLMs. FLMs have affirmative duties under section 169A(a) and (d) of the Clean Air Act as well as mandates to protect and manage public lands under the Wilderness Act[115] and the Organics Act[116]. Therefore, EPA should revise the Final Guidance to direct states that to work collaboratively with FLM to develop regional haze SIPs that satisfy federal agency duties and public resource protections.

XI. Overarching recommendations

A. EPA should emphasize that the end result must be reasonable progress.

EPA should make clear in a revised Final Guidance that the end result of any state's implementation plan must be real, reasonable progress. Consequently, each new plan must require that states actually reduce their emissions that contribute to visibility impairment. The statute requires each haze plan to contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress . . . ."[117] Therefore, any interpretation of the Regional Haze Rule via guidance should direct a state's long-term strategy to be more than just a hand waving exercise—each plan must require adequate emission limits and other enforceable measures to make reasonable progress.[118] EPA should revise the Final Guidance to explicitly provide that actually requiring emission reductions which constitute reasonable progress must be the outcome of the four-factor analysis to meet the applicable requirements; deliberation, no matter how well documented, is not enough. Emission reductions recognized through the four-factor analysis must result in emission reduction measures enforceable through a state or federal regional haze plan.

B. Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.

EPA must also revise the Final Guidance to clarify that decisions on which controls to require as part of long-term strategy cannot rest solely on controls required by past SIPs and state rules. Although EPA stated in the Draft Guidance that decisions on whether controls for a source or source category are cost-effective or provide sufficient visibility improvement cannot rely solely on past decisions evaluating controls for similar sources[119], that language is completely absent from the Final Guidance. EPA must revise the Final Guidance to state this point. For

[115] 16 U.S.C. §§ 1131-1136.
[116] 54 U.S.C. § 100101.
[117] 42 U.S.C. § 7491(b)(2).
[118] *See id.*
[119] Draft Guidance at 97, 103.

example, costs or technologies which were previously considered unreasonable or infeasible at a later date may become more common and may nevertheless be necessary in the second or future planning periods to make reasonable progress. Likewise, making reasonable progress in the current and future planning periods will require the implementation of controls that individually account for smaller visibility impacts than those contemplated in the first planning period and in other past emission reducing rules and permits. Therefore, EPA must revise the Final Guidance to direct states to conduct new source-specific, four-factor emission reduction analyses.

C. EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.

The Clean Air Act not only requires that existing visibility impairment be remedied, but that future impairment be prevented. 42 U.S.C. § 7491(a)(1). As such, it is imperative that each state's long-term strategy be required to include measures to prevent regional haze visibility impairment and that such plans take into account the effect of new sources, as well as existing sources of visibility impairment. EPA must revise its Guidance to comport with this requirement.

EPA has historically relied on the prevention of significant deterioration ("PSD") permitting program and the visibility new source review ("NSR") requirements mandated by 40 C.F.R. § 51.307[120] to address this requirement of the national visibility goal.[121] These provisions essentially mandate that new and modified major sources that are subject to major source permitting requirements do not adversely impact visibility in any Class I area. However, much has changed in the PSD and NSR permitting programs since 1980. The current PSD rules, as well as the major source nonattainment NSR rules, now exempt many modifications at existing major sources that were previously subject to PSD review. As a result, the PSD and visibility NSR rules do not provide as comprehensive Class I areas protections as they previously did, due to impacts from modified sources. Further, there have been significant increases in emissions near some Class I areas due to oil and gas emissions and other activities that are not adequately addressed by the PSD permitting program.

EPA must revise its Final Guidance to ensure that states prevent future impairment by analyzing new and modified emission sources and by requiring mitigation of the cumulative visibility-impairing emissions. As we discuss below, it is especially important for EPA to articulate that states consider minor, area, and other new growth, or modification of stationary sources that are not subject to the Class I area protections of the PSD permitting and visibility NSR requirements.

[120] 40 C.F.R. §51.307(b)(2) and (c) provides that the PSD requirements of 40 C.F.R. §51.166(o), (p)(1) through (2), and (q) apply to new and modified major proposing to locate in nonattainment areas that may have an impact on visibility in a mandatory Class I area.
[121] *See* 45 Fed. Reg. 80,089 (Dec. 2, 1980).

1. The 2002 PSD and nonattainment NSR Rule revisions exempt many modifications from PSD permitting that could result in large, visibility-impairing emission increases from existing major sources.

EPA has historically relied on the PSD and nonattainment/visibility NSR permitting programs to meet the requirement of preventing future impairment of visibility. The PSD permitting requirements specifically provide for ensuring that a new or modified major source will not adversely impact visibility in a Class I area[122], and the EPA's visibility NSR rules in 40 C.F.R. §51.307(c) require new and modified major sources proposing to locate in nonattainment areas that may impact visibility in a Class I area to meet these same requirements of the PSD program.[123] However, the December 2002 revisions to the PSD and nonattainment NSR permitting requirements significantly reduced the scope of modifications that would trigger PSD or nonattainment NSR as major modifications by drastically changing the methodology for determining whether a significant emission increase would occur as a result of a modification.[124]

Despite these significant regulatory changes which reduced the scope of modified sources subject to PSD and nonattainment NSR permitting, EPA has never re-evaluated its reliance on the major source permitting programs as sufficient to prevent future impairment of visibility. However, these rules, as revised in recent years, will likely allow significant increases[125] in actual emissions from existing sources to occur without any evaluation of the impacts on visibility and without even applying BACT or LAER, due to being exempt from PSD or nonattainment NSR permitting.

In summary, the PSD and nonattainment NSR rules as revised in 1992 and 2002 now exempt many modifications that would have previously been subject to major source permitting, including the visibility requirements of the PSD program and visibility NSR rules. Thus, while the rules still include vital provisions for the prevention of future visibility impairment, the PSD and visibility NSR rules are no longer adequate by themselves to ensure the prevention of future visibility impairment. In light of this, EPA should revise the Final Guidance to clarify that states may not solely rely on the PSD and visibility NSR programs to prevent future impairment of visibility. EPA must ensure that states specify requirements in their SIPs to prevent future visibility impairment from the new source growth in any state that may increase visibility-impairing pollution and thus affect Class I area visibility.

2. Minor, area, mobile, and other source emissions must be evaluated to prevent future, as well as remedy existing, impairment of visibility.

[122] 40 C.F.R. §52.21(o), (p)(1) and (2), and (q).
[123] 40 C.F.R. §51.307(b)(2) and (c).
[124] 67 Fed. Reg. 80,185, 80,186-89 (Dec 31, 2002) (also known as "NSR Reform" Rule).
[125] *See* Joseph Goffman, et al., EPA's Attack on New Source Review and Other Air Quality Protection Tools (Nov. 1, 2019), http://eelp.law.harvard.edu/wp-content/uploads/NSR-paper-EELP.pdf.

Although the Final Guidance mentions minor, area, mobile, and other emission sources, most of the discussion addresses major stationary sources. EPA should be more explicit in its expectation that states evaluate sources and source categories that are not major stationary sources as well, including the potential for growth in emissions from these sources. For example, given the increases in emissions from oil and gas development over the last 10 years,[126] it is clear that the existing SIPs and FIPs do not currently include adequate mechanisms for preventing visibility impairment from these sources as production ebbs and flows with economic conditions and other factors, such as deregulation and technology. EPA must revise the Final Guidance to clarify that states need to address these sources in the aggregate, rather than source-by-source.

There are several examples of rules and programs that may be necessary in a long-term strategy to prevent future impairment of visibility in Class I areas. EPA should revise the Final Guidance to direct states to consider these examples and include them where appropriate in SIPs.

a. Methods to address visibility-impairing emissions from oil and gas development

EPA should revise the Final Guidance to explicitly note that it expects states to review area sources like oil and gas, and should provide additional guidance on how to do so. Undoubtedly, this should begin with requiring states to collect better data on the emissions from oil and gas.

In many states, emissions from oil and gas development are a significant threat to visibility and air quality in Class I areas. Such development often occurs on federal lands that are near to or abut Class I areas For example, oil and gas development contributes to visibility impairment in public lands in Utah and Colorado where the NPS found that oil and gas development and leasing in the two states would "cause visibility impairment" at Dinosaur National Monument.[127] Additionally, NPS recently found impacts from oil and gas emissions at Carlsbad Caverns and San Pedro Parks Wilderness Class I areas, among others, based on 2008 emissions inventories—which do not capture more recent growth—and include only a portion of emissions from the production process.[128] Examples of Class I areas currently or potentially

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[126] "The U.S. Energy Information Administration ("EIA") reports that oil production growth in the United States has risen by about 3 million barrels per day (from 5.8 to 8.72 MMb/d) from January 2001 to July 2014 (EIA, 2014a). Natural gas production has increased from 53.74 to 70.46 billion cubic feet per day within this time period (EIA, 2014a). The trend is expected to continue with the number of oil and gas wells in the lower 48 states projected to increase by 84 percent between 2013 and 2040 (EIA, 2014b)." Thompson et al., Modeling to Evaluate Contribution of Oil and Gas Emissions to Air Pollution, 67 Journal of the Air & Waste Management Association Vol. 4, 445 (Sept. 2016), https://doi.org/10.1080/10962247.2016.1251508.

[127] Memorandum from Regional Director, Intermountain Region, National Park Service, to Planning and Environmental Coordinator, BLM 9 (2013); *see also* Memorandum from Superintendent, Dinosaur National Monument, National Park Service, to Field Office Manager, BLM Vernal Field Office 2 (Aug. 2017); Krish Vijayaraghavan et al., Ramboll Environ US Corporation, 2017); BLM, Colorado Air Resources Management Modeling Study (CARMMS): 2025 CAMx Modeling Results for the High, Low and Medium Oil and Gas Development Scenarios, 104-05 (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.

[128] Thompson et al., *supra* note 126, at 456; *see also* Table C6, *available at* https://www.tandfonline.com/doi/suppl/10.1080/10962247.2016.1251508?scroll=top.

impacted by oil and gas emissions include: Theodore Roosevelt and Lostwoods (Bakken Shale in eastern Montana and North Dakota); Wind Cave and Badlands (Powder River Basin in northeast Wyoming); Bridger and Fitzpatrick Wilderness Areas (Pinedale Anticline and Jonah Fields in western Wyoming); Mesa Verde (North and South San Juan Basin); Carlsbad Caverns and Guadalupe Mountains (Permian Basin in southeastern New Mexico and western Texas); and Canyonlands and Arches (Uintah, Paradox, and Piceance Basins in Utah and Colorado).

Significant information is available to enable states and EPA to develop strategies to reduce visibility-impairing emissions from this significant source category. However, these prior analyses do not substitute for meaningful consideration of oil and gas emissions reductions sufficient to meet the Regional Haze Rule's "reasonable progress" mandate. NPCA's recent report, "Oil and Gas Sector Reasonable Progress Four-Factor Analysis for Five Source Categories" assesses emissions controls for the five primary sources of visibility-impairing (and health harming) pollution in the sector: gas-fired reciprocating internal combustion engines ("RICE"); diesel-fired RICE; gas-fired combustion turbines; gas-fired heater, boilers, and reboilers; and flaring and thermal incineration of excess gas and waste gas.[129] The controls and practices included in this document represent various requirements for sources across the country and should be considered by states with emissions from the oil and gas sector.

Resource Management Plans ("RMPs") or land use plans issued by federal agencies explain how the agency will manage areas of public land over a period of time, usually ten to fifteen years. RMPs and amendments to those plans are required to go through a public review process under the National Environmental Policy Act ("NEPA"), which must include an analysis of projected impacts to all resources, including air quality. Such plans would include projections of oil and gas development, among other land use projections, on federal lands. Unfortunately, numerous RMPs have not been revised for decades, and only a few consider the effect of emissions from the planning area. EPA should revise the Final Guidance to require that states consider RMPs and other land use plans in determining the appropriate measures to prevent future impairment of visibility to include in regional haze SIPs. However, if RMPs are outdated or fail to consider the effects of visibility-impairing pollution from development, EPA must also indicate that those RMPs not be relied upon.

Recent NEPA analyses conducted for projected oil and gas development in RMPs can be useful tools for obtaining data regarding anticipated growth in such emissions. However, neither NEPA assessments nor RMPs are tools for preventing future impairment from oil and gas development. First, if adverse impacts are projected, the federal agency may make recommendations on mitigation methods to avoid adverse impacts, but neither the federal agency nor the local or state air permitting agency are under any obligation to implement such mitigation measures. Second, the federal agency is often making projections of expected amounts of development and in the types and emission rates of emissions units utilized. Those projections do

[129] Vicki Stamper & Megan Williams, Nat'l Parks Conservation Ass'n, Oil and Gas Sector Reasonable Progress Four-Factor Analysis for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration (Mar. 6, 2020) ("NPCA Report").

not always reflect the level of development that actually occurs, or the specific emission units and emission rates that are utilized. The Colorado Air Resources Management Modeling Study is one example of the type of information which can be developed in conjunction with the RMP process.[130]

In developing long-term strategies, EPA should direct states to use available information such as county-level reported emissions data and RMP and site-specific NEPA analyses, and request additional information to round out and make inventories accurate. To aid in this data gathering, EPA should direct industry to produce emissions inventories and submit them to states alongside an evaluation of emissions-reduction strategies and control technologies for this significant source of visibility impairment. Further, EPA should revise the Final Guidance to explicitly advise states on creating and making publicly available oil and gas emissions data.

States with significant oil and/or gas development should be required to consider the adoption of emission control regulations for the oil and gas development industry to reduce visibility-impairing emissions from such development.[131] Many states already require measures to reduce emissions from the sector. For example, California has enacted extensive air pollution requirements for oil and gas production, processing, and storage.[132] Colorado has also adopted emission requirements for the oil and gas industry.[133] Pennsylvania has also revised the state's oil and gas drilling regulations.[134] While these regulations may not be sufficient as to visibility impairment from the sector's emissions, the regulations provide relevant examples of states' decisions to address threats to air quality that are not covered by federal major source permitting requirements. EPA should identify the source types and associated emission-reducing measures available in the sector and use them to develop guidance to specify EPA's expectations of states in assessing these sources and requiring emission reduction measures from them. EPA must reconsider and revise the Final Guidance to require states to apply these and other control measures in their regional haze SIPs.

b. Minor New Source Review permitting programs

A state's minor NSR permitting program can be a useful tool to impose emission limitations and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal. EPA should revise the Final Guidance to direct states to model new or modified minor NSR sources for their impacts on visibility in Class I areas. States could thus determine if the source's emissions would be consistent with making reasonable progress towards the national visibility goal, similar to the requirement in 40 C.F.R. §51.307(c) of the visibility NSR rules. Such a provision would also be

[130] *See* BLM, Colorado Air Resources Management Modeling Study (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.
[131] NPCA Report at 7-10.
[132] California Air Resources Board, Oil & Natural Gas Production (last reviewed July 18, 2017), https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm.
[133] Colo. Regulation No. 7, Section XII, https://www.colorado.gov/pacific/cdphe/air/oil-and-gas-compliance.
[134] *See* Environmental Protection Performance Standards at Oil and Gas Well Sites, 46 Pa. B. 6431 (Oct. 8, 2016), http://www.pacodeandbulletin.gov/Display/pabull?file=/secure/pabulletin/data/vol46/46-41/1757.html.

consistent with section 7410(a)(2)(D)(i)(II) of the Clean Air Act, which requires SIPs to include adequate provisions prohibiting any source type from emitting any air pollutant which will interfere with measures to protect visibility. States could include criteria to ensure that the sources most likely to interfere with making reasonable progress are addressed, based on total emissions of visibility-impairing pollutants, distance to Class I areas, and/or other criteria focused on modifications at existing major sources that avoid PSD or nonattainment NSR review. EPA should instruct states to add such provisions to their minor NSR programs as necessary to ensure that their long-term strategies adequately prevent future impairment to visibility. Such provisions should also be incorporated and made enforceable through regional haze SIPs relying on such emission reductions to make reasonable progress.

States that decide to rely on minor NSR programs to prevent future impairment should be required to examine the relevant definitions and exemptions that exist in their programs to ensure that the types of sources that need to be addressed to prevent future impairment are indeed subject to the states' minor NSR programs. A state's minor NSR program also may need to be revised to include emissions from emitting units not typically covered under PSD permitting requirements, such as fugitive emissions.

Applicability at minor NSR sources should be based on projected changes in allowable or actual emissions from a baseline reflective of recent emissions. If a state is intending to rely on its minor NSR program to prevent future impairment of visibility, then the minor NSR program must be written in a manner to truly accomplish that intention. As other Clean Air Act programs fail to adequately integrate limits for new or modified sources, regional haze SIPs should be used directly for this purpose.

c. Provisions for other potential threats to visibility impairment

There are a number of source types other than those covered by a minor NSR permit program or oil and gas development that could potentially impair visibility. In recognition of this, EPA should revise its Final Guidance to recommend that states specifically include the analyses of these potential sources in their long-term strategies, and if necessary, adopt provisions to address them. For instance, if construction activities threaten future impairment, states should adopt control measures to mitigate air pollution at construction sites. As an example, the Sacramento Metropolitan Air Quality Management District applies air emissions requirements to construction sites.[135] California also has stricter mobile source emissions requirements (including for non-road engines) that apply under federal rules, and states with significant mobile source growth threatening future impairment could consider adopting such standards as their own.[136] EPA should encourage states to consider various measures to address

[135] *See* Sacramento Metro. Air Quality Management Dist., CEQA Guide, Ch. 3: Construction-Generated Criteria Air Pollutant and Precursor Emissions (April 2019), http://www.airquality.org/LandUseTransportation/Documents/Ch3ConstructionFinal4-2019.pdf.

[136] Congress preempted states from setting emission standards for mobile sources, except that California could set its own standards with EPA's permission and other states could opt into the stricter California standards (generally for ozone SIP purposes). 42 U.S.C. § 7543(e)(2)(B)(i)-(ii).

potential future Class I visibility impairment, based on the recent or planned growth in new source emissions expected for the state, that could threaten future impairment of visibility in any Class I area.

Additionally, to the extent that states have limited information on such sources, EPA should require that states collect and submit actual emissions increase data on minor modifications at existing sources in order to gather more information on the extent of minor source growth and on new minor, area, and other source growth.

Visibility-impairing emissions need to be inventoried and modeled from many sectors in order to properly inform the next round of haze plans. Several states have started collecting and submitting oil and gas emissions data to be inventoried and modeled for purposes of regional haze. For instance, the Western Regional Air Partnership has started collecting from its oil and gas producing states emissions for their modeling inventory.[137] However, there are several states not in the western region of the country, such as Pennsylvania and Virginia, which are significant producers of oil and gas, and should also be collecting and submitting oil and gas emissions data.[138] Furthermore, as noted *supra* section III.H, there is no inventory of emissions from the agricultural sector; states should develop such inventories and submit them with their regional haze SIPs.

Emissions data from wood burning devices should be modeled. As EPA has explained, the smoke from these devices "contains harmful particle pollution, also known as fine particulate matter or PM2.5, along with other pollutants including carbon monoxide, volatile organic compounds (VOCs), black carbon, and air toxics such as benzene."[139] EPA has also confirmed that residential wood combustion "accounts for 44 percent of total stationary and mobile polycyclic organic matter (POM) emissions, nearly 25 percent of all area source air toxic cancer risks and 15 percent of noncancer respiratory effects."[140] Furthermore, wood burning devices are a significant source of heating for many communities near Class I areas that struggle with regional haze pollution problems. Wood burning devices materially contribute to the significant proportion of particulate matter (fine and course) and VOC emissions that come from residential wood combustion in Arizona, Massachusetts, Minnesota, Nevada, Washington and other states, adding to regional haze visibility problems in Class I areas around the country.

While the collection and evaluation of much of this data should inform the next round of haze plans, we note that for the oil and gas sector, this data is sufficiently available such that regulation of the sector is appropriate and much needed in this second round of regional haze

[137] *See* Western Regional Air Partnership ("WRAP"), EGU Emissions Analysis Project, https://www.wrapair2.org/EGU.aspx.
[138] *See* U.S. Energy Info. Admin., Pennsylvania State Profile and Energy Estimates (last updated Aug. 15, 2019), https://www.eia.gov/state/?sid=PA; U.S. Energy Info. Admin., Virginia State Profile and Energy Estimates (last updated Sept. 15, 2019), https://www.eia.gov/state/?sid=VA.
[139] EPA, Fact Sheet: Overview of Final Updates to Air Emissions Requirements for New Residential Wood Heaters, at 1 (Feb 4, 2015), https://www.epa.gov/sites/production/files/2015-02/documents/20150204fs-overview.pdf.
[140] EPA, Strategies for Reducing Residential Wood Smoke, Publ'n No. EPA-456/B-13-001 at 4 (Mar. 2013), https://www.epa.gov/sites/production/files/documents/strategies.pdf.

planning. EPA should specify that in order for a state to satisfy the requirements of proposed 40 C.F.R. § 51.308(f), states must consider the cumulative impacts from minor and other source growth that may affect future visibility impairment. With this information, states can determine the number and types of new source growth and magnitude of emissions that may threaten future visibility impairment, which can then assist states in developing targeted measures to prevent future visibility impairment and address regional haze from these source types. Such measures should be required to be part of the long-term strategy of the regional haze SIP.

In summary, EPA must revise the Final Guidance to require long-term strategies to include measures to ensure the prevention of future visibility impairment, as well as the remedying of existing visibility impairment in Class I areas, in accordance with the national visibility goal of the Clean Air Act. While the PSD and visibility NSR programs have some effective provisions for ensuring that new and modified sources subject to those permitting requirements do not threaten future visibility impairment, those programs are not sufficient to fully address the statutory requirement of preventing future impairment to visibility. EPA should require states to evaluate the threats to future impairment to visibility in any Class I area and to adopt provisions within regional haze SIPs to minimize emissions from such sources, and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal.

## XII. Conclusion

The Conservation Organizations respectfully ask that EPA reconsider and revise the Final Guidance as mentioned above.

Sincerely,

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# Attachment 3

Alcoa Press Release announcing closure of the Alcoa Intalco Works facility.[1]

For Immediate Release: April 22, 2020

ALCOA INTALCO WORKS

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**Alcoa Corporation Announces Full Curtailment of Intalco Works**

FERNDALE, Wash. — Alcoa Corporation today announced that it will fully curtail its Intalco Works smelter located in Whatcom County amid declining market conditions.

The curtailment is expected to be complete by the end of July 2020, and the announced curtailment is included in the Company's first-quarter 2020 earnings press release, posted at www.alcoa.com.

"While our employees have worked diligently to improve the facility, the smelter is uncompetitive, and current market conditions have exacerbated the facility's challenges," said Alcoa President and CEO Roy Harvey. "This is difficult because of the impact on our employees, and we will ensure appropriate support as we work to safely curtail the facility."

Since the beginning of the year, aluminum prices have fallen more than 20 percent, down 45% from highs in 2018. In the first quarter of 2020, the Intalco smelter lost $24 million.

Steve Emig, Intalco Plant Manager, said the site's approximately 700 employees have worked together to address numerous challenges in an attempt to make the site competitive in the global market.

"Unfortunately, we cannot control the larger market dynamics," Emig said. "While this is a sad day, I remain proud of our Intalco team. We will work together during this difficult transition, focusing on safety and providing all available support to our employees."

Intalco will be working with its employees, the International Association of Machinists and Aerospace Workers (IAMAW) Union, and other stakeholders to minimize the impact of the curtailment.

Intalco, established in 1966, has 279,000 metric tons of nameplate operating capacity; 49,000 metric tons of production was curtailed earlier.

The Alcoa Foundation will continue its annual giving, donating $200,000 to qualifying non-profit organizations in the local community in 2020.

[1] "Ferndale's Alcoa Works to Close in July," The Fourth Corner News, https://thefourthcorner.com/ferndales-alcoa-intalco-works-to-close-in-july/ (April 22, 2020).

February 16, 2021, *Submitted with correction on February 19, 2021*[1]

Philip Gent
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Department of Ecology
P.O. Box 47600
Olympia, WA 98504-7600

*Submitted via email to*: philip.gent@ecy.wa.gov

Re: NPCA Comments Submitted for Informal comment period: Regional Haze SIP Revision - 2nd 10-Year Plan

Dear Mr. Gent:

The National Parks Conservation Association (NPCA), Sierra Club, the Duwamish River Cleanup Coalition (DRCC), Puget Soundkeeper Alliance (PSK), and Waste Action Project (WAP) ("Conservation Organizations") submit the following and attached comments regarding the Washington Department of Ecology's ("Ecology, DOE") informal comment period for its Regional Haze SIP Revision - 2nd 10-Year Plan.[2] We greatly appreciate Ecology's time and

[1] This corrected version of the comment letter includes four paragraphs that were inadvertently omitted from Section XI. on Environmental Justice, which are inserted at pages 55-56, starting with the paragraph "There are additional legal grounds…"

[2] "The Four-Factor Reasonable Progress Analysis for Ardagh Glass," was prepared for NPCA by Steven Klafka, P.E. BCEE, Environmental Engineer, Wingra Engineering, S.C. (Jan. 27, 2021) (This Analysis is referenced in Section III of these comments and attached as "Exhibit 1"). Sections III through IX were prepared for NPCA by Victoria Stamper, Boise, Idaho. Ms. Stamper is an independent air quality consultant and engineer with extensive experience in the regional haze program. Also enclosed are NPCA's comments submitted on the Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), which included proposed source-specific amendments for Ecology's Regional Haze SIP Revision, (Dec. 3, 2020). ("Exhibit 2").

efforts to provide for an inclusive early stakeholder engagement and comment on the four factor analysis reasonable progress (RP) reports submitted by the sources. Additionally, we commend Ecology for approaching its RP analysis by evaluating the industrial source categories, which provides for efficiencies in SIP development and public involvement, and equities in evaluating RP emission controls across each source category.

NPCA is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education. NPCA has over 1.4 million members and supporters nationwide with its main office in Washington, D.C. and 24 regional and field offices. NPCA's regional Northwest office is located in Seattle working on a variety of issues affecting Northwest national parks such as North Cascades, Olympic, and Mt. Rainier National Parks. NPCA is active nation-wide in advocating for strong air quality requirements in our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, global warming and mercury impacts on parks, and emissions from individual power plants and other sources of pollution affecting National Parks. NPCA's members live near, work at, and recreate in all the national parks of the Northwest, including those directly affected by emissions from Washington's sources.

The Sierra Club is a national nonprofit organization with 67 chapters and about 830,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club has long participated in Regional Haze rulemaking and litigation across the country in order to advocate for public health and our nation's national parks. The Washington Chapter of the Sierra Club has approximately 32,000 members.

Waste Action Project (WAP) has been around since 1994. WAP focuses on advocacy and education, and the Clean Water Act and has also provided technical and other support for communities for issues around the Clean Water Act, Superfund, Resource Conservation Recovery Act, and Model Toxics Control Act. WAP are a co-founder of Duwamish River Cleanup Coalition, and for the first few years oversaw DRCC's EPA Technical Assistance Grant for the Lower Duwamish Waterway Superfund Site. WAP has worked with impacted communities around the state to better understand their rights to clean water, and implementation of restoration and water quality improvement projects.

Puget Soundkeeper Alliance (PSK) is a regional organization whose mission is to protect and enhance the waters of Puget Sound for the health and restoration of our aquatic ecosystems and the communities that depend on them. PSK conducts outreach via stewardship, advocacy, monitoring and enforcement in order to achieve behavior change and systems change. PSK currently has 1,898 members who live, work, play, and worship all round Puget Sound and its tributaries, and have strong interests in protecting the waters from pollution and associated harms to community health. PSK is currently prosecuting Clean Water Act lawsuits against both Ardagh Glass and Ash Grove Cement for violations of National Pollution Discharge Elimination System (NPDES) permits. Though PSK is a water quality focused organization, it acknowledges and appreciates the undeniable intersectionality of water and air pollution with human health, and with racial and environmental justice.

PSK is also a coalition member of the Duwamish River Cleanup Coalition (DRCC/TAG). DRCC/TAG was founded in 2001 by ten non-profit organizations representing community, environmental, social justice, health, Tribal and small business stakeholders affected by the pollution and cleanup of Seattle's Duwamish River. Beyond monitoring the cleanup of Seattle's Duwamish River, we are a voice for the nearby community, which is negatively affected by the environmental, social and economic impacts of pollution. DRCC/TAG has worked closely with the affected communities in the Duwamish Valley for more than 18 years, including residents negatively impacted by Ardagh Glass legacy of frequent air pollution violations. The Duwamish Valley's riverfront neighborhoods Georgetown and South Park are situated within two miles of the Ardagh Glass facility and have long been disproportionately exposed to contamination, cumulative environmental injustices, and subsequent adverse health-related outcomes.

Residents who live in Georgetown and South Park have some of the highest health discrepancies in the City of Seattle. Childhood asthma hospitalization rates are the highest in the City. Heart disease death rates are 1.5 times higher than the rest of Seattle and King County. Life expectancy is 13 years shorter when compared to Laurelhust in North Seattle; one of Seattle's wealthiest neighborhoods.

Additionally, as you may know, in May 2020, NPCA shared the petition it submitted to the previous EPA Administrator - which sought reconsideration of the 2019 RH guidance[3] - alongside a cover letter to Washington.[4] In addition to NPCA, Sierra Club, Natural Resources Defense Council, Western Environmental Law Center, Appalachian Mountain Club, Coalition to Protect America's National Parks, and Earthjustice, signed the petition for reconsideration. As of the date of this comment letter, EPA has not responded to the Petition. Until the current EPA Administration withdraws the illegal approaches in the 2019 guidance, we trust states will not follow it, instead adhering closely to the regulation itself and working to achieve the Clean Air Act goal of Class I visibility restored to natural conditions.[5]

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[3] EPA issued the Final Guidance on August 20, 2019 via Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards to EPA Air Division Directors.

[4] "Petition for Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," submitted by National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Coalition to Protect America's National Parks, Appalachian Mountain Club, Western Environmental Law Center and Earthjustice, to former EPA Administrator Andrew Wheeler (May 8, 2020). ("Conservation Organizations Petition"). ("Exhibit 2," attached)

[5] The Petition explained that, as issued, the Final Guidance conflicts with this statutory objective, previous rulemaking and guidance; misdirects states as to how they can go about complying with their legal obligations to make reasonable progress towards restoring natural visibility to protected public lands; and otherwise fails to set expectations that comport with legal requirements for the second planning period. Further, we petitioned the prior Administrator to replace it with guidance that comports with the Clean Air Act ("CAA") and the Regional Haze Rule, 42 U.S.C. §§ 7491, 7492; 82 Fed. Reg. 3078 (Jan. 10, 2017); 71 Fed. Reg. 60,612 (Oct.13, 2006); 70 Fed. Reg. 39,104 (July 6, 2005); 64 Fed. Reg. 35,714 (July 1, 1999), and aids states in making progress towards achieving the national goal of natural visibility conditions at all Class I areas. Conservation Organizations Petition at 1-2. The Petition includes a detailed analysis of the issues. As of the date of this comment letter, EPA has not responded to our Petition. Until the current EPA withdraws the illegal approaches in the 2019 guidance, we trust states will not follow it instead adhering closely to the regulation itself and work to achieve the Clean Air Act goal of Class I visibility restored to natural conditions.

Our comments identify numerous issues and offer detailed suggestions to ensure that the four factor analyses Ecology proposes in the spring will be in line with the legal requirements of the Clean Air Act and federal regulations, and address visibility impairing emissions. Washington's regional haze plan presents a significant opportunity to not only improve the skies across the region's treasured public lands but also the air quality in communities across the state, including some of the most disproportionately affected by health harming pollution that can and must be abated.

We appreciate Ecology's consideration of these comments.

**Conservation Organizations' Comments**
**Washington Department of Ecology's Informal Comment Period**
**Regional Haze SIP Revision: 2nd 10-Year Plan**
**February 16, 2021**

# Table of Contents

## I. Introduction and Background

Washington is home to three national parks, Mount Rainier, Olympic, and North Cascades National Parks, and five wilderness areas, Alpine Lakes, Glacier Peak, Goat Rocks, Mount Adams, and Pasayten Wilderness Areas. Our national parks and wilderness areas are iconic, treasured landscapes and Washington is rich in national parks and natural areas.

Congress set aside these national parks and wilderness areas to protect our natural heritage for generations. Washington's protected areas also generate millions of dollars in tourism revenue, provide habitat for a range of species, and provide year-round recreational opportunities for residents. These special places are designated "Class I areas" under the Clean Air Act ("CAA") and as such, their air quality is entitled to the highest level of protection. Unfortunately, that requirement and promise is unfulfilled because the air in most Class I areas, including in Washington's most treasured natural areas, remains polluted by industrial sources, including the sources covered in our comments: Tesoro Refining (Anacortes Refinery); BP-Cherry Point Refinery; Phillips 66 Ferndale Refinery; U.S. Oil and Refining Company; Cardinal FG Winlock Glass Plant; Ardagh Glass Plant; Nippon Dynawave Packaging Company Longview; Georgia-Pacific Consumer Operations, LLC (GP Camas); WestRock Longview, LLC; WestRock PC, LLC Tacoma; Port Townsend Paper Corporation; Packaging Corporation of America (PCA) Wallula.

To improve air quality in our most treasured landscapes, Congress passed the visibility protection provisions of the Clean Air Act in 1977, establishing "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution."[6] "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities."[7] In order to protect Class I areas' "intrinsic beauty and historical and archeological treasures," the regional haze program establishes a national regulatory floor and requires states to design and implement programs to curb haze-causing emissions within their jurisdictions. Each state must submit for EPA review a SIP designed to make reasonable progress toward achieving natural visibility conditions.[8]

A regional haze SIP must provide "emissions limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal."[9] Two of the most critical features of a regional haze SIP are the requirements for installation of Best Available Retrofit Technology ("BART") limits on pollutant emissions *and a long-term strategy for making reasonable progress toward the national visibility goal*.[10] The haze requirements in the Clean Air Act present an unparalleled opportunity to protect and restore regional air quality by curbing visibility-impairing emissions from some of the nation's oldest and most polluting facilities.

[6] 42 U.S.C. § 7491(a)(1).
[7] *Id.* § 7491(g)(3).
[8] *Id.* § 7491(b)(2).
[9] 42 U.S.C. § 7491(b)(2).
[10] *Id.* § 7491(b)(2)(B); 40 C.F.R. § 51.308(d)(1)(i)(B).

Implementing the regional haze requirements promises benefits beyond improving views. Pollutants that cause visibility impairment also harm public health. For example, oxides of nitrogen (“$NO_X$”) are a precursor to ground-level ozone which is associated with respiratory disease and asthma attacks. $NO_X$ also reacts with ammonia, moisture and other compounds to form particulates that can cause and/or worsen respiratory diseases, aggravate heart disease, and lead to premature death. Similarly, sulfur dioxide (“$SO_2$”) increases asthma symptoms, leads to increased hospital visits, and can also form particulates. $NO_X$ and $SO_2$ emissions also harm terrestrial and aquatic plants and animals through acid rain as well as through deposition of nitrates (which in turn cause ecosystem changes including eutrophication of mountain lakes).

## II. The Regional Haze Reasonable Progress Legal Requirements

### A. Requirements for Periodic Comprehensive Revisions for Regional Haze SIPs

In developing its long-term strategy, a state must consider its anthropogenic sources of visibility impairment and evaluate different emission reduction strategies including and beyond those prescribed by the BART provisions.[11] A state should consider “major and minor stationary sources, mobile sources and area sources.”[12] At a minimum, a state must consider the following factors in developing its long-term strategy:

> (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
> (B) Measures to mitigate the impacts of construction activities;
> (C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
> (D) Source retirement and replacement schedules;
> (E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
> (F) Enforceability of emission limitations and control measures; and
> (G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.[13]

Additionally, a state

> Must include 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.[14]

In developing its plan, the state must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based.[15] All of this information is part of a state’s revised SIP and

[11] 40 C.F.R. § 51.308(f).
[12] *Id.* § 51.308(f)(2)(i).
[13] *Id.* § 51.308(f)(2)(iv).
[14] 40 C.F.R. § 51.308(f)(2)(i).
[15] 40 C.F.R. § 51.308(f)(2)(i).

subject to public notice and comment. A state's reasonable progress analysis must consider the four factors identified in the Clean Air Act and regulations. *See* CAA 169A(g)(1); 40 C.F.R. 51.308(f)(2)(i) ("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.")

EPA's 2017, Regional Haze Rule Amendments made clear that states are to 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.[16] Specifically, EPA explained in its final notice that it proposed, took and responded to comments and amended 40 C.F.R. § 51.308(f) to eliminate the cross-reference to 40 C.F.R. §51.308(d) to "codify …[its] long-standing interpretation of the way in which the existing regulations were intended to operate" to track "the actual [SIP] planning sequence" as follows, thus, states are required to:

(1) [C]alculate baseline, current and natural visibility conditions, progress to date and the URP;
(2) [D]evelop a long-term strategy for addressing regional haze by evaluating the four factors to determine what emission limits and other measures are necessary to make reasonable progress;
(3) [C]onduct regional-scale modeling of projected future emissions under the long-term strategies to establish RPGs and then compare those goals to the URP line; [FN73] and
(4) [A]dopt a monitoring strategy and other measures to track future progress and ensure compliance.[17]

Thus, to the extent Ecology's draft long-term strategy uses reasonable progress goals developed by the Western Regional Air Partnership (WRAP) *before* conducting the required four-factor analysis – which as discussed in Section X of these comments it appears it has done - it has reversed the order of the requirements. Ecology must first conduct the four-factor analyses, determine measures for reducing visibility impairing emissions and then use the results to develop proposed revisions to the reasonable progress goals.

The state's SIP revisions must meet certain procedural and consultation requirements.[18] The state must consult with the Federal Land Manager(s) and look to the Federal Land Managers' expertise of the lands and knowledge of the way pollution harms them to guide the state to ensure SIPs do what they must to help restore natural skies.[19] The rule also requires that in "developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers."[20]

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[16] 82 Fed. Reg. 3078, 3090-91 (Jan. 10, 2017).
[17] *Id.* at 3091.
[18] For example, in addition to the RHR requirements, states must also follow the SIP processing requirements in 40 C.F.R. §§ 51.104, 51.102.
[19] 40 C.F.R. § 51.308(i).
[20] *Id.* § 51.308(i)(3).

Finally, the duty to ensure reasonable progress requirements are met for purposes of the SIP rests with the state. While the WRAP plays an important role in providing support in regional haze planning, the state is ultimately accountable for preparing, adopting, and submitting a compliant SIP to EPA. Further, as discussed more fully in Section X of these comments, Ecology has an obligation to cite to the technical support documentation it proposes to rely on and use as part of its SIP revision.[21]

B. Requirements for Sources with Permits (and State "RACT") In Process: Four-Factor Analysis Required

We provide the following comments regarding RP requirements pertaining to sources with permits in process, which include the Cardinal FG Winlock Glass Plant. In addition to the requirements that apply to this source, we provide an analysis of potential controls for Cardinal FG Winlock Glass Plant in Section V, below. While the Company requested a permit to install emission controls, the permit does not exempt it from a four-factor analysis and establishment of emission limits to provide reasonable progress towards the national visibility goal. Ecology should conduct a proper four-factor analysis for the Cardinal FG Winlock Glass Plant and ensure that emission limits are imposed to address the facility's visibility impairing pollution.

For a source that is found subject to the required reasonable progress Four-Faction Analysis as a result of a state's reasonable progress screening process, the state must ensure the Analysis is conducted. Neither the Act nor EPA's rules provide an "off-ramp" for a source in this situation. A RACT analysis that Ecology may have gone through (or will go through in the future) for an individual source or source category is separate and distinct from the four-factor reasonable progress analysis requirement. The regional haze program includes identifying and issuing requirements to remedy *existing* impairment and also requirements necessary to prevent *future* impairment. The four-factor RP and RACT analysis apply different factors and consider different information because they are different programs with different objectives. A RACT analysis and controls must not be used as an offramp to the requirement to conduct the four-factor RP analysis and determine RP for the source. The regional haze four-factor RP analysis and determination applies *in conjunction with* other CAA programs. Therefore, as individual sources and source categories are modified and subject to emission controls (e.g., RACT), Ecology must take into consideration *all* requirements of the CAA (e.g., RP four-factor analysis and determination) and not make one decision in isolation, set aside distinct requirements or delay their implementation. A state's issuance of a permit does not replace its responsibility under the CAA to conduct the required RP four-factor analysis.

Additionally, since Ecology did not provide a Q/d value, as you'll see below in our comments, we provide that evaluation. Based on the Q/d value, it's clear that a Four-Factor Analysis is required for this source. The duty to ensure reasonable progress requirements are met for purposes of the SIP rests with the state, not the source. Therefore, if a source is unwilling to prepare the Analysis, Ecology must conduct the analyses to inform its reasonable progress determination. The lack of Ecology's analysis on this source appears to suggest that doing nothing to meet the reasonable progress requirements is justified because the source "proposes"

[21] *See, e.g.,* 40 C.F.R. §§ 51.100, 51.102, 51.103, 51.104, 51.105 and Appendix V to Part 51.

controls on "some" of the visibility impairing pollutants. Ecology fails to provide any authority or analysis for this "do nothing" approach.

Because the Q/d value for this source shows a Four-Factor Analysis is required, Ecology must conduct the required four-factor analysis for the source, including requirements for emission limitations and other measures based on the source's current operations. If the source elects some other emission controls, which are less stringent than what would be required under the Four-Factor Analysis, Ecology should further analyze the source to evaluate additional controls. Furthermore, since the source is subject to the reasonable progress requirements, Ecology must integrate the source into its regional haze plan and include provisions to ensure permit provisions are enforceable in the SIP.

Ecology cannot merely rely on the permit provisions for this source. The Clean Air Act requires states to submit implementation plans that "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of achieving natural visibility conditions at all Class I Areas.[22] The Regional Haze Rule requires that states must revise and update its regional haze SIP, and the "periodic comprehensive revisions must include the "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress as determined pursuant to [51.308](f)(2)(i) through (iv)."[23] At this point, as discussed above, the State's materials lack the required Four-Factor Analysis, emission limitations and other requirements necessary. Furthermore, EPA's Guidance further explains these requirements:

> This provision requires SIPs to include enforceable emission limitations and/or other measures to address regional haze, deadlines for their implementation, and provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.[24]

Thus, EPA's Guidance recognizes EPA's long-standing position that while the SIP is the basis for demonstrating and ensuring state plans meet the regional haze requirements, state-issued permits must complement the SIP and SIP requirements.[25] State-issued permits must not frustrate SIP requirements.[26] For example, sources with PSD permits under Title I must not hold permits that allow emissions that conflict with SIP requirements.[27] Additionally, the Act's Title V operating permits collect and implement all the Act's requirements – including the

[22] 42 U.S.C. § 7491(a)(1), (b)(2).
[23] 40 C.F.R. § 51.308(f)(2); 40 C.F.R. § 51.308(d)(3)(v)(F) (Enforceability of emission limitations and control measures).
[24] "EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," at 42-43 (August 20, 2019), https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf. (While NPCA filed a Petition for Reconsideration regarding EPA's issuance of the 2019 Guidance, it does not dispute the information in the Guidance referenced here regarding enforceable limitations, which cite to the "General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990, 74 Fed. Reg. 13498 (April 16, 1992).
[25] 74 Fed. Reg. 13498, 13568 (April 16, 1992).
[26] Furthermore, to the extent stationary source are granted permits by rule or other mechanisms, these other categories that allow construction and operation must also complement SIP requirements.
[27] Additionally, the proposed SIP revisions fail to contain source-specific "measures to mitigate the impacts of construction activities." 40 C.F.R. § 51.308(d)(3)(v)(B).

requirements in the SIP – as applicable to the particular permittee. And sources with Title V permits must not hold such permits if they contain permit terms and conditions that conflict with the SIP and Clean Air Act SIP requirements.

C. It is Inconsistent with the CAA's Requirements to Use Air Quality Modeling to Decide Reasonable Process Controls

As explained above the reasonable progress four-factor analysis includes consideration of the following:

- Consider 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 sources.[28]

The four-factor analysis is clearly bounded by the information collected under each of the factors. Air quality impacts, modeling results, and emission inventories are not information collected pursuant to any of the four-factors. Therefore, to the extent a state adds an additional factor or factors to its four-factor analysis the state's analysis is inconsistent with the four-factor analysis requirement. As discussed in these comments, as part of its reasonable progress analysis Ecology uses visibility impacts to reject emission controls at several of the sources, and because visibility is not one of the four statutory factors, the State cannot rely on it to exclude emission reducing measures from a source that otherwise satisfies the four statutory factors.

## III. Four-Factor Reasonable Progress Analysis Ardagh Glass Plant

Enclosed at Exhibit 1 is the "Four-Factor Reasonable Progress Analysis for Ardagh Glass, Inc. in Seattle, Washington, which evaluates the feasibility of installing emission control equipment for air pollutants that are precursors to regional haze.

## IV. Comments on Four-Factor Analyses Submitted for the Oil Refineries

According to the four-factor submittals made for the refineries, Ecology requested four-factor analyses for each fluid catalytic cracking unit (FCCU), boiler with heat input greater than 40 MMBtu/hr, and heater with heat input greater than 40 MMBtu/hr that has not been retrofitted with NOx controls since 2005.[29] However, if any of these units have been retrofit with NOx controls since 2005, at most the units have been retrofitted with combustion controls. SCR should still be evaluated as an add-on control measure for units with LNB or ULNB or other combustion controls, even if installed in the past 15 years.

[28] CAA 169A(g)(1); 40 C.F.R. 51.308(f)(2)(i).
[29] *See*, e.g., BP Cherry Point Refinery Regional Haze Four Factor Analysis, April 2020 (hereinafter "BP Cherry Point Analysis") at 2.

Ecology apparently also limited the evaluation of NOx controls to low NOx burners (LNB), Ultra-low NOx burners (ULNB), and selective catalytic reduction (SCR).[30] It is not clear why Ecology did not also ask for a review of selective noncatalytic reduction (SNCR). McIlvaine Company indicates that urea-based SNCR used at refinery process units and boilers has generally achieved 50-70% NOx reduction.[31] In its AP-42 emission factor documentation for heaters and boilers from 1998, EPA stated that LNBs and FGR were the two most prevalent control techniques being used at gas-fired heaters and boilers.[32] Thus, if LNB or ULNB are truly not technically feasible for a heater or boiler, Ecology should at least require FGR be evaluated as a NOx control. In addition, LNBs plus FGR should also be evaluated as a control measure, which EPA states can reduce NOx by 60-90%.[33] Further, Ecology should require that combustion controls be evaluated in conjunction with SNCR and SCR to determine the most effective and the most cost-effective NOx emissions controls.

In addition, Ecology should not limit evaluation of LNBs and ULNBs for units greater than 40 MMBtu/hour capacity, as such burners are available for smaller units.[34] The California Air Resources Board (CARB) determined as far back as 1991 that heaters and boilers as small as 5 MMBtu/hour or greater could meet NOx "best available retrofit control technology" (BARCT) limits of 30 ppmv (or about 0.036 lb/MMBtu).[35] However, more recently, California's South Coast Air Quality Management District (AQMD) concluded that even lower NOx limits, as low as 9 ppm, could be met with ULNB at boilers and process heaters as small as 2 MMBtu/hr.[36] This was based on actual ULNB retrofit experience at boilers and heaters in the San Joaquin Unified Air Pollution Control District (SJVAPCD).[37] The Ventura County Air Pollution Control District in California also found that boilers and process heaters as small as 2 MMBtu/hr could meet NOx limits of 9 ppm with ULNB.[38] Thus, Ecology should not limit the evaluation of reasonable progress controls to only heaters and boilers greater than 40 MMBtu/hr. Ecology should also request companies demonstrating that the retrofit of ULNBs is not technically feasible and for which SNCR or SCR are truly not cost effective to evaluate the costs of replacing an existing boiler or heater with a new unit equipped with state-of-the-art ULNBs. If a unit is near the end of its useful life, this could be a very cost effective and readily implementable approach to reducing NOx emissions.

None of the five refineries for which Ecology requested four-factor analyses found that LNB/ULNB or SCR were appropriate for regional haze reasonable progress controls. Either the companies claimed that a control, such as ULNB, was not technically feasible for a heater or

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30 *Id.*
31 *See* http://www.mcilvainecompany.com/industryforecast/refineries/background1/text/Chapter%20X/Chapter%20X.htm.
32 EPA, AP-42, Section 1.4.4 (last revised 1998), available at: [https://www.epa.gov/sites/production/files/2020-09/documents/1.4_natural_gas_combustion.pdf](https://www.epa.gov/sites/production/files/2020-09/documents/1.4_natural_gas_combustion.pdf).
33 *Id.*
34 *See*, e.g., BP Cherry Point Refinery Regional Haze Four Factor Analysis, April 2020 (hereinafter "BP Cherry Point Analysis") at 2.
35 As discussed in Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 120. ("Exhibit 3," attached.)
36 *Id.* at 121.
37 *Id.*
38 *Id.* at 121-122.

boiler, or a company claimed that controls were not cost effective. Tesoro used a cost effectiveness threshold of $3,430/ton which the company claims is from the $3,400/ton used by EPA in 2011 for the Cross-State Air Pollution Rule scaled to today's dollars.[39] Based on this threshold, Tesoro found that no additional NOx controls (whether low NOx burners or SCR) would be cost effective for its heaters and boilers. However, no justification has been provided for use of this cost threshold or any cost threshold for defining measures necessary to make reasonable progress. For any cost threshold selected by a state, EPA's regional haze guidance requires that the State Implementation Plan (SIP) "explain why the selected threshold is appropriate for that purpose and consistent with the requirements to make reasonable progress."[40]

With respect to determining whether a NOx control is cost effective for a particular heater or boiler, it is important to consider the costs that similar sources have had to bear to meet Clean Air Act requirements for NOx. For example, several Californian Air Districts as well as the states of Texas, Massachusetts, New York, and Georgia have set NOx emission limits for existing heaters and boilers that are reflective of the use of LNB/ULNB, SNCR, or SNCR.[41] While these emission limits were often set to address ozone and/or PM2.5 nonattainment issues, the fact is that each of these controls can be quite cost effective. For example, a SJVAPCD cost analysis for ULNBs shows that the retrofitting of such controls to meet a NOx limit of 6 ppm would have cost effectiveness values ranging from $545/ton to $3,270/ton, with the higher cost effectiveness values being at smaller units (the smallest size unit evaluated was 30 MMBtu/hr) and/or lower capacity factors.[42] In addition, based on a SJVAPCD cost analysis for SCR to meet NOx emission rates of 2.5 ppm, SCR was found to have a cost effectiveness of $1,025/ton to $6,149/ton for heaters and boilers as small as 30 MMBtu/hr, with the lowest cost effectiveness values for the larger units and units that operate at higher capacity factors.[43] It is important to note that these cost effectiveness analyses were done using a higher interest rate of 5.5% than currently applies,[44] as the bank prime lending rate is currently 3.25%.

In determining cost effective controls for the heaters, boilers and FCCU's at the refineries selected for review, Ecology must consider the fact that other similar sources have been required to retrofit LNB/ULNB or similar combustion controls, or SCR/SNCR if combustion controls are not feasible to meet an emission limit. We encourage Ecology to review Table 42 of the attached March 6, 2020 report of four-factor analyses for the oil and gas industry,[45] which includes a list of state and local air agency emission limits and rules applicable to existing natural gas-fired heaters and boilers. As that report indicates, the most stringent NOx limit for units greater than or equal to 75 MMBtu/hour required of existing sources in the listed state and local rules is 5 ppm,

[39] *Id.* at 10.
[40] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 39.
[41] Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 139-145. ("Exhibit 3," attached.)
[42] *Id.* at 125 (Table 36).
[43] *Id.* at 135 (Table 41).
[44] *Id.* at 125 (fn 568) and at 135 (fn 615).
[45] Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 139-145. ("Exhibit 3," attached.)

which most likely reflects use of SCR. The most stringent limits for smaller heaters and boilers between 2 to 75 MMBtu/hr range between 5 to 12 ppm, which reflect LNB/ULNB at the minimum, if not SNCR/SCR. There are several examples of similar sources having to bear the costs of these controls to meet Clean Air Act requirements. Ecology would thus be justified in finding these controls, LNB/ULNB at the minimum, to be cost effective for the heaters, boilers, and FCCUs evaluated in the refinery four-factor analyses. We urge Ecology to give preference to the most effective control that will remove the highest rate of NOx achievable and otherwise satisfy the Four-Factor reasonable progress analysis.

In most cases, the cost analyses submitted by the refineries overstate costs and understate emissions reductions, and so the cost effectiveness numbers should not be relied upon by Ecology without significant revisions. More specific concerns with each company's four-factor analyses of NOx controls are provided below.

A. Tesoro Refining (Anacortes Refinery) Four-Factor Analyses

Tesoro Refining & Marketing Company LLC's (Tesoro's) Anacortes Refinery submitted a four-factor analysis for fluid catalytic cracking unit (FCCU) and boilers and heaters greater than 40 MMBtu/hr. Specifically, Tesoro submitted a four-factor analysis for following emission units at the refinery:

- Crude Heater 2
- Vacuum Flasher Heater
- CCU Feed Heater
- DHT Feed Heater
- Boiler 1
- Boiler 2
- Boiler 3
- NHT Feed Heater
- NHT Column C-6600 Reboiler
- CR Feed Heaters
- CO Boiler 2
- FCCU.

Tesoro only evaluated controls for NOx. The company stated that Ecology only requested evaluations of low NOx burners/ultra-low NOx burners and SCR. The following provides comments on Tesoro's cost effectiveness analyses in its Four-Factor submittal.

*Issues with Four-Factor Analyses for Boilers and Heaters at Tesoro Refinery*

1. Tesoro did not conduct four-factor analyses for any heaters or boilers that had installed NOx controls since 2005.[46] However, none of Tesoro's heaters or boilers that it exempted from a four-factor analysis have installed SCR to reduce NOx emissions. Given that SCR is such a highly effective NOx control, the state should require the evaluation of SCR installation at all boilers and heaters at the refinery.

[46] Tesoro Four-Factor Analysis at 3.

2. Tesoro used 2014 as the baseline year for cost effectiveness analysis for the various emission units, but it did not provide any analysis to show that 2014 emissions were reflective of emissions expected in 2028. EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions.[47] The use of emissions from over six years ago needs to be justified. For example, Tesoro assumed the CCU Feed Heater, Unit F-301, only operated 839 hours per year.[48] The Crude Heater 2 (Unit F-102) and the Vacuum Flash Heater (F-201) were evaluated at operational levels over 8,000 hours per year, whereas most other units were evaluated at lower operating hours in the range of 4,600-5,500 hours per year.[49] The annual hours of operation define how much pollution is emitted in a year and thus how much pollution can be decreased with a particular control being evaluated, which can greatly impact the cost effectiveness of a pollution control. Thus, the state should ensure that the assumptions are reasonable projections of emissions in 2028.

3. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Tesoro used an interest rate of 5.5%. In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

4. In the SCR cost analyses, a very high and unjustified cost of ammonia was assumed of $900/ton.[50] No basis was cited for this cost. The company calculated a cost per gallon for 19.5% aqueous ammonia of $3.513 per gallon.[51] Yet, EPA's SCR Control Cost Manual chapter assumes a much lower cost for 29% aqueous ammonia of $0.293/gallon, based on the average cost for ammonia for 2016 from the U.S. Geological Survey's Minerals Commodities Summaries for which EPA provided a weblink.[52] The U.S. Geological Survey Minerals Commodities Report currently lists the 2019 average cost for ammonia at $230/ton.[53] Thus, Tesoro's costs of ammonia reagent were greatly overstated. It is also not clear why only 19.5% aqueous ammonia was considered as a reagent. EPA's Control Cost Manual states that 29% aqueous ammonia is the more commonly used form of aqueous ammonia.[54] Use of anhydrous ammonia is the least expensive form of the reagent and is commonly used at utility installations.[55] The State must ensure that Tesoro

[47] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[48] Tesoro Four-Factor Analysis at pdf page 39 (Appendix A at F-301).
[49] *Id.* at Appendix A in SCR cost spreadsheets for Units F-652, F-751, F-752, F-753, F-6600, F-6650/1/2/3, F-6601, and F-304.
[50] *See*, e.g., Tesoro Four-Factor Analysis, Appendix A at F-102 (pdf page 26 of document).
[51] *Id.*
[52] See EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[53] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 116, available at https://www.usgs.gov/centers/nmic/mineral-commodity-summaries.
[54] EPA, Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 15.
[55] *Id.* at pdf page 5.

evaluates the most cost-effective approaches to controlling NOx emissions with SCR and also that Tesoro does not use a wholly unjustified and very high cost for ammonia of $900/ton.

5. Tesoro's cost effectiveness evaluations of SCR used the EPA SCR cost spreadsheet that has been made available with its SCR Control Cost Manual chapter for all units except for the fluid catalytic cracking unit (CCU) for which Tesoro used a cost estimate from a similar installation.[56] For the CCU, only a one-page printout of an apparent spreadsheet was provided for review. The State should request the underlying calculations that went into the spreadsheet as well as the cost estimates from a planned SCR installation at an FCCU at the other Marathon refinery that Tesoro relied on. Without that data, it is not clear if the SCR cost analysis for the CCU complied with EPA's Control Cost Manual. In addition, the NOx control cost effectiveness of the SCR installation at the other Marathon facility should be made available and considered by the State, among other factors, in deciding whether SCR is cost effective at the CCU at the Tesoro refinery.

6. With respect to the use of EPA's cost spreadsheet for SCR, there is one entry made by Tesoro into the EPA cost spreadsheet that ultimately defines the size of the SCR reactor, and that is the "base case fuel gas volumetric flow rate factor" which is in units of $ft^3$/min-MMBtu/hr. These numbers seem very high in comparison to the values EPA uses for coal-fired boilers for which EPA defines as a constant for fuel type regardless of unit size or actual gas throughput.[57] Tesoro's fuel gas volumetric flow rate factors for each combustion turbine are roughly a factor of 100 higher than the fuel gas volumetric flow rate factors of 484-547 cubic $ft^3$/min-MMBtu/hour (depending on coal type) used by EPA in its SCR cost spreadsheet for coal-fired boilers.[58] The State should request documentation and justification for the base case fuel gas volumetric flow rate factors used by Tesoro.

7. Tesoro assumed NOx control efficiencies across the SCRs of 90%-96% for most boilers and heaters, with the exception of Boiler 3 (F-753) for which Tesoro only assumed a control efficiency of 75%.[59] The State should request justification for only assuming 75% control for Boiler 3.

8. With respect to the cost evaluations for ULNB for the heaters and boilers, Tesoro only assumed a 20-year life of controls in determining the amortizing the capital costs of control.[60] There was no basis provided for only assuming a 20-year life of ULNB.[61] If ULNB only have a life of 20-years, then the State should not exempt any boiler or heater from a four-factor analysis if it has installed controls by 2005 as claimed by Tesoro,[62] because the low NOx burners installed at Crude Heater 1 (F-101), Crude Heater 3 (F-

[56] Tesoro Four-Factor Analysis at Appendix A.
[57] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 59, Table 2.6.
[58] Compare values used for flue gas volumetric flow rate factors in Tesoro Four-Factor Analyses, Appendix A, to Table 2.6 of EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction.
[59] Tesoro Four Factor Analysis, Appendix A, SCR spreadsheet printouts.
[60] *Id.* at pdf pages 84-91.
[61] *Id.* at 15.
[62] *Id.* at 3.

103), CGS Column C-113 Reboiler (F-104), BenSat Column C-6601 Reboiler (F-6602), and Carbon Monoxide Boiler 1 (F-302)[63] will be at the end of their useful lives during the second planning period. Ultra-low NOx burners should have a useful life 25-30 years or more. In evaluations of best available retrofit technology (BART) for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[64] In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR.[65] Thus, the State should not allow the use of a useful life of an ULNB any less than 25 years for the Tesoro units.

9. Tesoro did not provide justification for the NOx emission rate for the ULNBs. For most units, Tesoro assumed a 0.04 lb/MMBtu achievable NOx rate with ULNB.[66] Yet, the CGH Heater F-104, which has ULNBs,[67] is subject to a NOx limit of 0.035 lb/MMBtu.[68] The State should thus require an evaluation of ULNBs to meet a similar 0.035 lb/MMBtu NOx rate. For Units F-751 and F-752 which are boilers, a much higher NOx rate of 0.11 lb/MMBtu was assumed for ULNB.[69] Yet, Unit F-753 which is also a boiler of similar size to Units F-751 and F-752 but which has been retrofitted with low NOx burners and internal flue gas recirculation (IFGR),[70] Tesoro assumed a NOx rate of 0.04 lb/MMBtu in its evaluation of SCR cost effectiveness[71] which presumably reflects its current emission rate. Thus, Tesoro's evaluation of ULNBs for Units F-751 and F-752 should have evaluated cost effectiveness to meet a similar NOx rate as has been achieved at Unit F-753 with a similar control.

10. Tesoro did not evaluate the cost effectiveness of the most effective control – ULNB plus SCR. Ecology must require Tesoro to evaluate this level of control for its heaters and boilers.

B. BP-Cherry Point Refinery Four-Factor Analyses

BP Cherry Point submitted a four-factor analysis for nine emission units at the refinery:

- Crude Charge Heater;
- South Vacuum Heater;
- #1 Reformer Heaters;
- #2 Reformer Heaters;
- Naphtha HDS Charger Heater;

[63] *Id.*
[64] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).
[65] BP Cherry Point Four-Factor Analysis at 14.
[66] Tesoro Four-Factor Analyses, Appendix A, at pdf pages 84-91.
[67] *Id.* at 3-4.
[68] January 26, 2010 Air Operating Permit #013R1 for Tesoro Refining and Marketing Company at 72 (Permit Term 5.2.13).
[69] Tesoro Four-Factor Analyses, Appendix A, at pdf pages 87-88.
[70] *Id.* at page 7.
[71] *Id.,* Appendix A at F-753 (pdf page 61).

- Naphtha HDS Stripper Reboiler;
- Hydrocracker R-4 Heater;
- #1 Hydrogen Plant (North and South Furnaces);
- #5 Boiler.

BP states that Ecology narrowed the request to only LNB/ ULNB and SCR. BP analyzed the cost effectiveness of LNB/ULNB and SCR for these units and found that no controls were cost-effective. The following provides comments on BP's cost effectiveness analyses in its Four-Factor submittal.

*Issues with Four-Factor Analyses for BP Cherry Point*

1. BP used 2016 as the baseline year for cost effectiveness analysis for the various emission units, but it did not provide any analysis to show that 2016 emissions were reflective of emissions expected in 2028. EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions.[72] In addition, BP did not identify each units' baseline NOx emissions rates in terms of lb/MMBtu, nor did BP specify the baseline operating hours/capacity factor of each unit. Such information is necessary to review to ensure that the company selected a reasonable period of baseline emissions for its cost effectiveness analyses that reflects a reasonable projection of emissions in 2028, as required by EPA's regional haze guidance. Ecology must request that the company make that information available in BP Cherry Point's four-factor analysis. Ecology should also request that BP justify its year of baseline emissions as reflective of future operations in 2028.

2. One of the deficiencies in BP Cherry Point's cost analyses is that it used a 5% interest rate in amortizing capital costs.[73] BP claimed that this interest rate was based on the past Federal Reserve Prime Rate, but the Federal Reserve Prime Rate has been at 3.25% since March 2020.[74] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[75] In a cost effectiveness analyses being done today, even a 5.0% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

3. For all of the units except the #5 boiler and the #3 reformer heater, BP used cost estimates that were previously done in 2010 and which reflected a 2007 dollar basis.[76] BP scaled those costs up from 2007 dollars to 2020 dollars using the Nelson Farrar Refinery Construction cost index, which increased capital costs by 41%.[77] EPA's Control Cost

[72] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[73] BP Cherry Point Four-Factor Analyses at 5.
[74] https://fred.stlouisfed.org/series/DPRIME.
[75] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[76] BP Cherry Point Four-Factor Analyses at 9-12.
[77] *Id.* at 12.

Manual cautions against attempting to escalate costs more than five years from the original cost analysis.[78] EPA states that "[e]scalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate."[79] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. Thus, Ecology should request that BP obtain current retrofit cost information for these units. Notably, for SCR, EPA's SCR cost effectiveness spreadsheet can be used to estimate costs of SCR, as was used by the Tesoro Refinery in its cost effectiveness analyses.

4. BP Cherry Point stated that LNBs/ULNBs were not technically feasible on the crude charge heater, the naphtha HDS charge heater, the naphtha HDS stripper reboiler, and the hydrocracker R-4 heater due to flame impingement and that they would need to rebuild the heater to accommodate the burner retrofit.[80] A review of the air operating permit for BP Cherry Point shows that most of these heaters and boilers were installed fifty years ago in 1970. Given the age of the heaters, it could be more economical to replace the heaters and boilers with new heaters equipped with state-of-the-art ultra-low NOx burners. Ecology should request BP to evaluate the cost effectiveness of replacing the 50-year old heaters and boilers.

5. BP Cherry Point Assumed that LNB and ULNB could only achieve NOx emission rates of 0.055 to 0.060 lb/MMBtu for forced and balanced draft heaters with air preheaters.[81] The company provided no citation or support for that statement. NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[82] Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[83]

6. BP applied retrofit factors to the costs of SCR which would increase the capital costs due to purported retrofit difficulty, but BP provided no justification for the use of retrofit factors. For the one unit for which BP utilized EPA's SCR cost spreadsheet, it must be noted that the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology should request justification and documentation for any retrofit factors used in BP's cost analyses.

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[78] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[79] *Id.*
[80] BP Cherry Point Analysis at 15-17.
[81] BP Cherry Point Analysis at 7.
[82] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144. ("Exhibit 3," attached.)
[83] BP Cherry Point Analysis at 19.

7. BP assumed a cost for ammonia reagent in the SCR systems of $0.33/lb, or $660/ton, which is unreasonably high.[84] No basis was cited for this cost. EPA's SCR Control Cost Manual chapter assumes a much lower cost for 29% aqueous ammonia of $0.293/gallon, based on the average cost for ammonia for 2016 from the U.S. Geological Survey's Minerals Commodities Summaries for which EPA provided a weblink.[85] The U.S. Geological Survey Minerals Commodities Report currently lists the 2019 average cost for ammonia at $230/ton.[86] Thus, BP's costs of ammonia reagent were greatly overstated. Use of anhydrous ammonia is the least expensive form of the reagent and is commonly used at utility installations. The State must ensure that BP evaluates the most cost-effective approaches to controlling NOx emissions with SCR and also that Tesoro does not use a wholly unjustified and very high cost for ammonia of $900/ton.

8. Ecology should ask BP to doublecheck and request documentation the number of operating hours assumed in the calculation of ammonia reagent costs for SCR. BP assumed an SCR would operate 8,784 hours per year (i.e., the total number of hours in a leap year) in estimating the reagent costs for SCR at the South Vacuum Heater, which clearly is in error as that could only occur once every four years. BP also assumed 8,760 hours of operation for estimating reagent costs for SCR at the #1 Hydrogen Plant North and South Reforming Furnaces. Ecology must ensure that the assumed operating hours for estimating reagent costs are consistent with the baseline emissions and baseline capacity factor assumed in each SCR cost analysis.

9. With respect to non-air quality impacts of SCR controls, BP has indicated that spent catalyst will require off-site disposal or recycling.[87] However, EPA's Control Cost Manual states that use of rejuvenated and regenerated catalyst can both reduce catalyst replacement costs and eliminate catalyst disposal costs. Ecology must ensure that BP's SCR cost analyses assumes the most cost-effective options for catalyst replacement.

10. BP assumed it would take 7 to 10 years to implement additional NOx control strategies.[88] Yet, the company has not proposed to install any control strategies in its four-factor submittal. The company states that it would need to follow the refinery maintenance TAR schedule which is 5 to 6 years per unit, but it seems very unlikely that each unit is on the same maintenance schedule and instead the maintenance schedules are likely staggered. Ecology should request an evaluation of the time to install controls for each boiler and heater, the #1 reformer heaters, the #2 reformer heater, and Ecology should also evaluate how long it took BP to install controls adopted to meet BART which requires compliance within five years.

[84] BP Cherry Point Four-Factor Analysis at Attachment B.
[85] See EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[86] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 116, available at https://www.usgs.gov/centers/nmic/mineral-commodity-summaries.
[87] BP Cherry Point Four-Factor Analysis at 13.
[88] BP Cherry Point Four-Factor Analyses at 13.

C. Shell Puget Sound Refinery

The Shell Puget Sound Refinery is located near Anacortes, Washington. Shell submitted a four-factor analysis evaluating NOx controls for its FCCU and boilers and heaters greater than 40 MMBtu/hr. The company stated that Ecology only requested evaluations of LNB/ULNB and SCR.[89] The units that Shell evaluated NOx controls for include the following:

- Vacuum Pipe Still (VPS) Charge Heater 1
- VPS Charge Heater 2
- Vacuum Tower Heater
- Delayed Coking Unit (DCU) Charge Heater
- Hydrotreater Unit 1 (HTU1) Charge Heater
- HTU1 Fractionator Reboiler
- HTU2 Stripper Reboiler
- Hydrotreater Unit 2 (HTU2) Fractionator Reboiler
- Catalytic Reforming Unit #2 (CRU2) Charge Heater
- CRU2 Interheater #1
- CRU2 Stabilizer Reboiler
- Erie City Boiler #1
- Cogen Gas Turbine Generator (GTG) Heat Recover Steam Generator (HRSG) with duct burners (GTG1, GTG2, and GTG3)

Shell states that Ecology narrowed the request to only LNB/ ULNB and SCR. Shell analyzed the cost effectiveness of LNB/ULNB and SCR for these units.

Shell concludes that SCR is not a cost-effective control for NOx emissions at the refinery.[90] Shell indicates that the cost-effectiveness of LNB is much lower than those of SCR. However, Shell argues that a more thorough, unit-specific evaluation by vendors will be required to determine if the installation of low-NOx is technically feasible and cost-effective.[91] It must be noted that several of the units listed above already have LNBs installed, as do some additional units at the Shell refinery which were not evaluated in the four-factor analysis. That fact is persuasive in that LNBs are widely used at refinery heaters and boilers, and thus at least that level of control should be required to meet reasonable progress. The following provides comments on Shell's cost effectiveness analyses in its Four-Factor submittals.

*Issues with Four-Factor Analyses for Shell Puget Sound Refinery*

1. Shell used 2019 emissions as baseline and stated that 2019 "is representative of the anticipated actual emissions in the near future."[92] However, emissions data in the 2017 National Emission Inventory show that NOx emissions for the refinery were 1,054 tons per year, which is significantly higher than the 592.6 tons per year of NOx that Shell has indicated was emitted in 2019. Ecology must ensure that the year of emissions selected

[89] Shell Puget Sound Refinery Four-Factor Analysis at 2-1.
[90] *Id.* at 5-5.
[91] *Id.*
[92] *Id.* at 4-1.

by Shell does not reflect a period of lower levels of operation and that the 2019 baseline level operations and emissions are expected to continue at that rate.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Shell used an unreasonably high interest rate of 7%.[93] In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units except the Erie City Boiler, the Shell cost effectiveness analyses assumed a 20-year life of controls.[94] No justification has been included in Shell's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[95] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years.[96] In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR.[97] Thus, the State should not allow the use of a 20-year useful life of a LNB or an SCR to be assumed in the cost effectiveness analyses for any of the Shell units, with one possible exception being the Erie City Boiler 1 (ECB1).

4. With respect to the remaining useful life of the Erie City Boiler 1, Shell provided brief information for this boiler that "substantial upgrades will be required to replace the boiler's refractory and the boiler skin" and that "the remaining useful life of the unit is expected to be less than 10 years."[98] The company assumed 8 years in its four-factor analysis for the Erie City Boiler.[99] Importantly, Shell did not indicate that it would be retiring Erie City Boiler 1. If Shell plans on these substantial upgrades to the boiler, then Ecology should not consider this boiler as having a shortened remaining useful life in the NOx control cost effectiveness analyses. If the company is planning to retire and replace the boiler within the next 8 years, then Ecology should impose an enforceable retirement date for the boiler.[100] Ecology should also require that any replacement boiler should, at the very least, be equipped with state-of-the-art ULNB. The Erie City Boiler 1 currently

[93] *Id.* at 5-3.
[94] *Id.* at 8-0.
[95] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).
[96] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[96] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 80.
[97] BP Cherry Point Four-Factor Analysis at 3, 14 and at Attachment B.
[98] Shell Four-Factor Analyses at 5-5.
[99] *Id.*
[100] *See* EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 20, which states that a state "may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028."

has no controls and, at 182.4 tons per year, has the highest emissions of NOx of any of the units evaluated in Shell's four-factor analysis. Ecology should not allow this unit or its replacement to avoid controls because it is either going to be reconstructed or removed from service in the next 8-10 years.

5. In its four-factor analysis, Shell assumed that LNG would only achieve a NOx emission rate of 0.06 lb/MMBtu. Shell provided no justification for assuming such a high NOx emission rate with LNB. As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[101] In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control.[102] It is also worth noting that Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[103]

6. For SCR, Shell assumed a NOx removal efficiency of 90%. Yet, Tesoro and BP often assumed NOx removal efficiencies of 95% in their evaluation of SCR. BP assumed SCR would achieve 95% control or 5 ppm, whichever resulted in higher emissions.[104] A review of the printout of SCR cost spreadsheets provided in Appendix A of Tesoro's Four-Factor Analyses shows that the company assumed a controlled NOx rate of 0.01 lb/MMBtu with SCR for almost all units evaluated, which typically reflected a NOx control efficiency in excess of 90% for most units.[105] Ninety percent control is clearly not the maximum level of reduction that could be achieved with SCR, and Ecology should request Shell to evaluate NOx control at levels of NOx removal similar to what BP and Tesoro have assumed.

7. For SCR, Shell used the EPA SCR cost spreadsheet made available with EPA's recent updated to its SCR chapter of the Control Cost Manual. However, Shell applied a very high retrofit factor of 1.5 to each SCR evaluation, without providing any justification for any retrofit factor much less a retrofit factor that increases SCR costs by 50%. It must be noted that the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology must scrutinize the use of any retrofit factor in Shell's SCR cost estimates using EPA's SCR cost spreadsheet. EPA's SCR cost spreadsheet already adds a retrofit factor of 20% compared to the cost of SCR installation at a new unit for SCR retrofits at existing units.[106] EPA's Control Cost Manual states that higher retrofit factors than 1 can be used "provided the reasons for using a higher retrofit factor are appropriate

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[101] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144. ("Exhibit 3," attached.)
[102] May 5, 2015 Air Operating Permit AOP 014R1M1 for Shell Puget Sound Refinery at 13 and 127.
[103] Tesoro Four-Factor Analysis at Appendix A (at pdf pages 84-91).
[104] BP Cherry Point Four-Factor Analysis at 8.
[105] Tesoro Four-Factor Analysis at Appendix A. Not that Tesoro only assumed 75% control across the SCR at its Boiler 3, which was not sufficiently documented or justified as discussed above.
[106] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 66.

and fully documented."[107] No unit-specific documentation of the justification for higher SCR retrofit factors was included in Shell's four-factor submittal.

8. Shell appears to have assumed that that the gas stream of each heater/boiler would need to be reheated to accommodate SCR.[108] However, Shell did not provide any data on each of the units for which these costs were included in the SCR cost effectiveness to indicate that reheating the gas stream to accommodate SCR operation is necessary. Ecology must request further information to justify the inclusion of these costs for reheating the gas stream for each of the emission units at the Shell refinery.

D. Phillips 66 Ferndale Refinery Four-Factor Analysis

Phillips 66 provided four-factor analyses of NOx controls for the following emission units at its Ferndale Refinery:[109]

- Crude Heater
- Crude Heater
- Alky Heater
- Reformer - Pretreater heater
- Reformer heater
- Reformer heater
- Reformer heater
- Reformer heater
- #1 Boiler
- #2 Boiler
- #3 Boiler
- DHT Heater
- S-Zorb Heater.

Phillips 66 states that Ecology narrowed the request to only LNB/ ULNB and SCR.[110] Phillips 66 analyzed the cost effectiveness of LNB/ULNB and SCR for these units and concluded that neither SCR nor LNB are cost-effective control for NOx emissions reductions at the refinery.[111] The following provides comments on the four-factor analyses submitted by Phillips 66.

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[107] *Id.* (emphasis added)
[108] Shell Four-Factor Analysis at Appendix B.
[109] Regional Haze Four-Factor Analysis, Phillips 66 Ferndale, WA Refinery, June 2020 (hereinafter referred to as "Phillips 66 Four-Factor Analysis"). Note that Phillips 66 originally submitted its four-factor analysis in April of 2020, but it revised the analysis in June 2020 because it claimed that "the burners currently in operation for the alkylation heater (17F-1) and the DHT heater (33F-1) are considered low-NOx burners," and thus Phillips 66 excluded LNBs as a control to be evaluated for these units. *See* June 29, 2020 cover letter to Phillips 66 June 2020 Four-Factor Analysis.
[110] Phillips 66 Four-Factor Analysis at 1-1.
[111] *Id.*

*Deficiencies and shortcomings in the Phillips 66 Analyses are as follows:*

1. Phillips 66 used a five-year average of annual emissions from 2014-2018 as baseline emissions.[112] EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions. Ecology should request that Phillips 66 show each of the five years of emissions available for review so it can be determined if the average likely reflects expected emissions in 2028. The state should ensure that the assumptions are reasonable projections of emissions in 2028.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. Phillips 66 used an unreasonably high interest rate of 7%. In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units, the Phillips 66 cost effectiveness analyses assumed a 20-year life of controls.[113] No justification has been included in Shell's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[114] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years. In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR. Thus, the State should not allow the use of a useful life of a LNB or an SCR to be assumed in the cost effectiveness analyses for any of the Phillips 66 units.

4. Phillips 66 assumed high NOx rates with LNB in the range of 0.09 to 0.23 lb/MMBtu.[115] As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower.[116] In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control.[117] It is also worth noting that Tesoro evaluated LNB/ULNB to

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[112] *Id.* at 4-1.
[113] *Id.* at Appendix B.
[114] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natural gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944, 18953, 18960 (Apr. 8, 2015).
[115] *Id.*
[116] *See* Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144. ("Exhibit 3," attached.)
[117] May 5, 2015 Air Operating Permit AOP 014R1M1 for Shell Puget Sound Refinery at 13 and 127.

meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.[118] Moreover, the #1 boiler, the DHT Heater, and the S-Zorb heater at the Phillips 66 refinery, which all have LNB, have baseline NOx emission rates in the range of 0.031 to 0.042 lb/MMBtu, per Phillips 66 SCR cost effectiveness analysis.[119]

5. Phillips 66 only assumed 90% control of NOx with SCR.[120] Yet, Tesoro and BP often assumed NOx removal efficiencies of 95% in their evaluation of SCR. BP assumed SCR would achieve 95% control or 5 ppm, whichever resulted in higher emissions.[121] A review of the printout of SCR cost spreadsheets provided in Appendix A of Tesoro's Four-Factor Analyses shows that the company assumed a controlled NOx rate of 0.01 lb/MMBtu with SCR for almost all units evaluated, which typically reflected a NOx control efficiency in excess of 90% for most units.[122] Ninety percent control is clearly not the maximum level of reduction that could be achieved with SCR, and Ecology should request Phillips 66 to evaluate NOx control at levels of NOx removal similar to what BP and Tesoro have assumed.

6. Phillips 66 assumed continual operation every hour of the year (i.e., 8,760 hours per year – 100% capacity factor) in assessing reagent and other operational expenses of SCR.[123] Unless the company demonstrates that its emitting units operated 8,760 hours per year during the baseline period, this assumption results in overstated operational costs.

7. Phillips 66 included the same dollar amount for construction and management costs, contingencies, and escalation for every SCR cost analysis. Specifically, the company included costs of $3,841,150 for construction and management, $1,323,000 for contingencies, and $168,300 for escalation for each SCR cost analysis.[124] These were all identified as "indirect capital costs."[125] Such costs are typically scaled to the size of the unit, but these costs clearly have not been scaled. For many units, these costs exceed the costs of the SCR and the direct installation costs. Ecology must request further justification for these indirect capital costs to determine if identical costs are justified for each SCR installation. In addition, to the extent these costs include owner's costs, such as the costs for owner activities to oversee the project regarding engineering, management, and procurement, or to fund the project, such costs must be excluded from the cost effectiveness analysis. EPA does not allow owner's costs to be included in cost effectiveness analyses under the Control Cost Manual.[126]

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[118] Tesoro Four-Factor Analysis at Appendix A (at pdf pages 84-91).
[119] Phillips 66 Four-Factor Analysis, Appendix B (at pdf page 44).
[120] *Id.* at 5-2.
[121] BP Cherry Point Four-Factor Analysis at 8.
[122] Tesoro Four-Factor Analysis at Appendix A. Not that Tesoro only assumed 75% control across the SCR at its Boiler 3, which was not sufficiently documented or justified as discussed above.
[123] Phillips 66 Four-Factor Analysis, Appendix B.
[124] *Id.* (at pdf page 45).
[125] *Id.*
[126] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 65.

E. U.S. Oil & Refining Company – Tacoma Refinery Four-Factor Analysis

U.S. Oil submitted a four-factor analysis of NOx controls for the following emission units:[127]

- Package Steam Boiler B-4
- Package Steam Boiler B-5
- Process Heater H-11.

U.S. Oil states that Ecology narrowed the request to only LNB/ ULNB and SCR.[128] U.S. Oil analyzed the cost effectiveness of LNB/ULNB and SCR for these units and concluded that neither SCR nor LNB are cost-effective control for NOx emissions reductions at the refinery.[129]

*Deficiencies and shortcomings in the U.S. Oil Four-Factor Analyses are as follows:*

1. Rather than using a level of baseline emissions based on historical emissions at the emission units of the Tacoma refinery, U.S. Oil states that it is "implementing changes during the refinery's upcoming turnaround in early 2021 that will add significantly to heat recovery, thereby reducing the fired duties of these sources."[130] Specifically, the baseline NOx emissions assumed for the three emission units evaluated are as follows:

| | |
|---|---|
| Unit B-4 (Package Steam Boiler) | 24.96 tpy NOx |
| Unit B-5 (Package Steam Boiler) | 10.39 tpy NOx |
| Unit H-11 (Process Heater) | 31.56 tpy NOx[131] |

Ecology should request or make public how U.S. Oil's projection of future NOx emissions from these units compares to recent annual NOx emissions from these emission units.

EPA's regional haze guidance states with respect to the baseline control scenario for the control analysis that:

> Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable

[127] Regional Haze Four-Factor Analysis for U.S. Oil & Refining Co., Tacoma Refinery, April 2020 (hereinafter "U.S. Oil Four-Factor Analysis) at 3-2.
[128] *Id.* at 1-1.
[129] *Id.* at 1-1 to 1-2.
[130] *Id.* at 4-1.
[131] *Id.*

basis for quantifying any change in future emissions due to operational changes may be another.

EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.

Ecology should thus require that U.S. Oil identify the details of its changes, including providing verifiable information to quantify its projection of the future NOx emissions of these units. Further, Ecology should evaluate whether the changes at the refinery should be made into enforceable requirements, so as to ensure the refinery's continued operation at these emission rates throughout the second planning period and beyond.

2. In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate. The current bank prime rate is 3.25%. Yet, much higher interest rates were used in amortizing capital costs of controls evaluated in the four-factor analyses. U.S. Oil used an unreasonably high interest rate of 7%.[132] In a cost effectiveness analyses being done today, an interest rate of 3.25% must be used to be consistent with EPA's Control Cost Manual. Use of a higher interest rate results in significantly higher annualized capital costs.

3. For all units, the U.S. Oil cost effectiveness analyses assumed a 20-year life of controls.[133] No justification has been included in U.S. Oil's four-factor analysis for only assuming a 20-year life of controls in the cost-effectiveness analyses. As previously stated, in evaluations of BART for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[134] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years. In the four-factor submittals made to Ecology, BP Cherry Point assumed 25 years for LNB/ULNBs as well as SCR. Thus, the State should not allow the use of a useful life of a LNB or an SCR to be assumed in the cost effectiveness analyses for any of the U.S. Oil units.

3. U.S. Oil assumed NOx rates with LNB in the range of 0.060 to 0.072 lb/MMBtu. As was discussed above, NOx emission limits for refinery heaters and boilers reflective of LNB/ULNB are typically set at 0.040 lb/MMBtu or lower. In fact, one unit at the Shell Puget Sound refinery, the 95 MMBtu/hour CDHDS Heater in the Hydrotreater Unit #3, which was constructed in 2003, is subject to a NOx limit of 0.035 lb/MMBtu with an LNB for NOx control. It is also worth noting that Tesoro evaluated LNB/ULNB to meet NOx emission rates of 0.040 lb/MMBtu in its four-factor analyses.

[132] *Id.* at B-2.
[133] *Id.* at 5-5.
[134] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).

4. U.S. Oil only assumed 90% control of NOx with SCR. Yet, Tesoro and BP often assumed NOx removal efficiencies of 95% in their evaluation of SCR. BP assumed SCR would achieve 95% control or 5 ppm, whichever resulted in higher emissions. A review of the printout of SCR cost spreadsheets provided in Appendix A of Tesoro's Four-Factor Analyses shows that the company assumed a controlled NOx rate of 0.01 lb/MMBtu with SCR for almost all units evaluated, which typically reflected a NOx control efficiency of greater than 90% for most units. Ninety percent control is clearly not the maximum level of reduction that could be achieved with SCR, and Ecology should request U.S. Oil to evaluate NOx control at levels of NOx removal similar to what BP and Tesoro have assumed.

5. U.S. Oil applied a 1.5 retrofit factor to the costs for both ULNB and for SCR.[135] This is a very high retrofit factor which essentially increases the capital costs of controls by 50%. Yet, U.S. Oil did not provide unit-specific information to justify the 1.5 retrofit factor applied to each ULNB and each SCR evaluation. With respect to SCR, it must be noted that the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. Ecology must scrutinize the use of any retrofit factor in U.S. Oil's SCR cost estimates using EPA's SCR cost spreadsheet. EPA's SCR cost spreadsheet already adds a retrofit factor of 20% compared to the cost of SCR installation at a new unit for SCR retrofits at existing units. EPA's Control Cost Manual states that higher retrofit factors than 1 can be used "provided the reasons for using a higher retrofit factor are appropriate and fully documented." No unit-specific documentation of the justification for higher SCR retrofit factors was included in U.S. Oil's four-factor submittal. With respect to the 1.5 retrofit factor applied to the cost effectiveness evaluation of ULNBs, U.S. Oil states this factor was included "to account for the additional challenges of retrofitting a low-NOx burner in an existing heater."[136] This is not sufficient documentation to justify a retrofit factor, especially such a high retrofit factor.

7. U.S. Oil states that SCR will require flue gas reheating.[137] However, U.S. Oil did not provide any data on each of the units for which these costs were included in the SCR cost effectiveness to indicate that the current exhaust gas stream would necessitate reheating to accommodate effective SCR operation. Ecology must request further information to justify the inclusion of these costs for reheating the gas stream for each of the emission units at the Tacoma refinery.

## V. Analysis of Potential Controls for Cardinal FG Winlock Glass Plant

The Cardinal FG Winlock plant is a flat glass manufacturing plant in Winlock, WA. According to Ecology, its 2014 NOx emissions were 791.5 tons per year based on 2014

[135] *Id.* at 5-4 and at Table B-2 (pdf page 45).
[136] *Id.* at Table B-2.
[137] *Id.* at 5-5.

emissions.[138] In 2017, its NOx emissions were a bit higher at 809.1 tons per year.[139] Thus, the facility is a large source of NOx. Based on 2017 emissions and considering Class I areas in which the facility had a Q/d equal to or greater than 5, we calculate a cumulative Q/d of the Cardinal FG Winlock Glass Plant as 48.0. Therefore, the Cardinal Glass Plant is subject to the four-factor analysis. As discussed above in Section II.B. and in this section, the RH four-factor analysis applies to the Cardinal Glass Plant *in conjunction with* any other CAA requirements. That additional regulatory requirements also apply to this or any other sources does not obviate the need for the state to comply with reasonable progress requirements, nor excuse timely compliance.

Ecology did not request a four-factor analysis of pollution controls for the Cardinal Glass Plant. Instead, Ecology proposes to rely on the fact that the company recently submitted a permit application to install SCR controls, remove existing NOx controls, and increase production of plate glass. However, the company is also planning on an increase in glass production capacity, from 650 tons per day to 750 tons per day. Ecology presented the difference in potential to emit based on the current emission limits and the permit modification limits in an attempt to focus on the reduction in potential emissions for NOx and the seemingly minor increases for PM10, PM2.5, and to a lesser extent SO2.[140] However, in conducting the required four-factor analysis, Ecology must present what the increase in emissions that could be allowed with the permitted increase in glass production capacity compared to current actual emissions. For example, the Cardinal FG Winlock Glass Plant's SO2 emissions in 2017 were 49 tons per year and the facility and the facility-wide potential to emit after the permit modification will be 114.21 tons per year.[141] Ecology must explain whether this means SO2 emissions could actually increase by the difference of these two values, or by 65.21 tons per year. Similarly, the 2017 actual PM10 emissions of the facility were 58 tons per year and the facility-wide potential to emit PM10 after the permit modification is 141.96 tons per year,[142] so does this mean with the glass plant capacity increase that PM10 could actually increase by 83.96 tons per year?

With respect to NOx, the facility-wide NOx emissions in 2017 were 723 tons per year, and the facility-wide potential to emit is 249.62 tons per year,[143] which only reflects a NOx reduction with SCR of 65.5% which is much lower than the 90%+ control efficiency that SCR is capable of achieving. In part, the higher annual NOx emissions after the capacity increase are because the exhaust gas is currently planned to be reheated to "raise the exhaust steam temperatures to the range required for proper SCR operation."[144] However, the increased exhaust temperature will "require the existing spray dryer and electrostatic precipitator (ESP) to operate at higher temperatures, reducing their collection efficiency."[145] Further, Ecology states

[138] *Id.*
[139] Data from EPA's National Emissions Inventory for 2017.
[140] WDOE Draft SIP Revision, Chapter 11, at 21 (Table 3).
[141] *Id.* at 12 and 21.
[142] *Id.*
[143] *Id.*
[144] *Id.* at 20.
[145] *Id.* at 21.

that the "increased temperature results in a greater fuel consumption and SO2 emissions."[146] Thus, the addition of the SCR, which the company is planning to install in lieu of, rather than in addition to, its existing combustion control system will not be utilized to its maximum emission reduction potential and will result in increases in other visibility-impairing pollutants.

Consistent with the four-factor analysis, Ecology must evaluate other options to accomplish the NOx emission reductions without increasing other visibility-impairing pollutants. First, Ecology must explain why it is justifiable for Cardinal FG Winlock to stop using the 3R Process to control NOx, when it could readily use additional NOx controls in addition to the 3R Process. For example, if the company were required to add SCR along with the existing 3R process, which is currently required by the Cardinal FG Winlock's prevention of significant deterioration (PSD) permit,[147] it could operate SCR at a NOx removal efficiency that both reduced NOx emissions from current levels and ensured the same efficacy of PM and SO2 removal by not having to reheat the gas stream. In addition, the use of low temperature catalysts should have been evaluated for the SCR, to avoid having to heat the gas stream and reduce the effectiveness of the PM and SO2 controls. Another option Ecology should consider for the Cardinal Glass Plant is the use of ceramic catalyst filters along with the existing 3R process, which can reduce NOx at lower temperatures than conventional SCR and also capture particulate and SO2. This control method is discussed in the January 27, 2021 Four-Factor Reasonable Progress Analysis for the Ardagh Glass plant in Seattle, Washington, done by Wingra Engineering, S.C. and attached as Exhibit 1.

Ecology applies RACT and asserts that it need not also independently address reasonable progress requirements. Application of RACT, does not negate Ecology's obligation to comply with the RHR and evaluate reasonable progress requirements for a source the state identified in its RP screening process. This includes not only identifying and issuing requirements to remedy existing impairment but also requirements necessary to prevent future impairment. RACT and RP are not equivalent programs and do not host the same objectives. As such it is incumbent on the agency to conduct a reasonable progress analysis for Cardinal and determine RP for the source.

Ecology must also comply with the state law RCW 70A.15.2220 cited in its draft Long-Term Strategy as part of its review and determination of appropriate regional haze emission limitations for the Cardinal FG Winlock glass plant in its Regional Haze plan for the second implementation period. It has an obligation to ensure RACT level controls are met. RACT is defined under Washington State law as:

> *[T]he lowest emission limit* that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved

[146] *Id.* at 21-22.
[147] *See* PSD-03-03, Amendment 2, issued by WDOE to Cardinal FG Company on Dec. 13, 2010, at Condition 15.1.1.

by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls. RACT requirements for a source or source category shall be adopted only after notice and opportunity for comment are afforded.

RWA 70A.15.1030(20) (emphasis added).

While SCR is a control technology capable of meeting the lowest emission limit, the proposed NOx emission limit does not appear to require the "lowest emission limit" that can be met with SCR. Further, with the decreases in SO2 and PM removal efficacy that will occur as a result of the SCR installation, it is questionable whether the SO2 and PM emission limits reflect RACT in that the revised emission limits do not reflect the lowest emission limit for the spray dryer and electrostatic precipitator that are installed at the glass furnace.

## VI. Comments on Four-Factor Analyses Submitted by the Northwest Pulp & Paper Association (NWPPA) for the Washington Pulp and Paper Mills

The Northwest Pulp & Paper Association (NWPPA) submitted four-factor analyses for several emission units associated the following five pulp and paper mills:

- Nippon Dynawave Packaging Company Longview
- Georgia-Pacific Consumer Operations, LLC (GP Camas)
- WestRock Longview, LLC
- WestRock PC, LLC Tacoma
- Port Townsend Paper Corporation
- Packaging Corporation of America (PCA) Wallula.[148]

The NWPPA report is organized by reviewing controls for similar emission units at each of the six pulp and paper mills. Specifically, NWPPA evaluated controls for the following recovery furnaces, controls for lime kilns, and controls for power boilers at each pulp and paper mill.

**Figure 1. Recovery Furnaces Evaluated by NWPPA.**

| Facility Name | Emissions Unit Description | Fuels Currently Fired | Current Pollution Controls |
|---|---|---|---|
| Nippon Dynawave Packaging Company | Recovery Furnace No. 10 | Black Liquor Solids, No. 6 Fuel Oil | Electrostatic Precipitator |
| WestRock Longview Mill | Recovery Furnace 19 | Black Liquor Solids, Natural Gas, No. 2 and No. 6 Fuel Oil | Electrostatic Precipitator |

[148] *See* Dec. 5, 2019 Reasonably Available Control Technology Analysis for Washington Pulp and Paper Mills, Northwest Pulp & Paper Association (hereinafter "December 2019 NWPPA Report").

| | | | |
|---|---|---|---|
| WestRock Longview Mill | Recovery Furnace 22 | Black Liquor Solids, Natural Gas, No. 2 and No. 6 Fuel Oil | Electrostatic Precipitator |
| WestRock Tacoma Mill | Recovery Furnace No. 4 | Black Liquor Solids, No. 6 Fuel Oil* | Electrostatic Precipitator |
| Port Townsend Paper Corporation | Recovery Furnace | Black Liquor Solids, No. 2 Fuel Oil | Electrostatic Precipitator |
| PCA Wallula Mill | No. 2 Recovery Furnace | Black Liquor Solids, No. 2 Fuel Oil, Natural Gas | Electrostatic Precipitator |
| PCA Wallula Mill | No. 3 Recovery Furnace | Black Liquor Solids, No. 2 Fuel Oil, Natural Gas | Electrostatic Precipitator |

**Figure 2. Lime Kilns Evaluated by NWPPA.**

| Facility Name | Emissions Unit Description | Fuels Currently Fired | Current Pollution Controls |
|---|---|---|---|
| Nippon Dynawave Packaging Company | Lime Kiln | Natural Gas | Electrostatic Precipitator<br>Staged Combustion |
| WestRock Longview Mill | Lime Kiln 3 | Natural Gas, Fuel Oil | Scrubber |
| WestRock Longview Mill | Lime Kiln 4 | Natural Gas, Fuel Oil | Scrubber |
| WestRock Longview Mill | Lime Kiln 5 | Natural Gas, Fuel Oil | Electrostatic Precipitator |
| WestRock Tacoma Mill | Lime Kiln No. 1 | Natural Gas, No. 6 Fuel Oil | Scrubber |
| WestRock Tacoma Mill | Lime Kiln No. 2 | Natural Gas, No. 6 Fuel Oil | Scrubber |
| Port Townsend Paper Corporation | Lime Kiln | Natural Gas, No. 2 Fuel Oil | Scrubber |
| PCA Wallula Mill | Lime Kiln | Natural Gas, No. 2 Fuel Oil | Scrubber |

**Figure 3. Power Boilers Evaluated by NWPPA.**

| Facility Name | Emissions Unit Description | Fuels Currently Fired | Current Pollution Controls |
|---|---|---|---|
| Nippon Dynawave Packaging Company | Power Boiler 6 | Natural Gas | N/A |
| Nippon Dynawave Packaging Company | Power Boiler 7 | Natural Gas | N/A |
| Nippon Dynawave Packaging Company | Power Boiler 9 | Natural Gas | N/A |
| Nippon Dynawave Packaging Company | Hogged Fuel Boiler No. 11 | Hog fuel, Bituminous Coal, Sludge, ultra-low sulfur diesel | ESP, Multiclone, DSI System, Overfire Air System |
| GP Camas | No. 5 Power Boiler | Natural Gas | Flue Gas Recirculation, Low NOx Burners |
| WestRock Longview Mill | Power Boiler 20 | Natural Gas, Fuel Oil, Biomass* | WESP, Scrubber, SNCR |
| WestRock Tacoma Mill | Power Boiler No. 6 | Natural Gas, No. 6 Fuel Oil | Low NOx Burners |
| WestRock Tacoma Mill | Power Boiler No. 7 | Natural Gas, Biomass | ESP, Scrubber |
| Port Townsend Paper Corporation | Power Boiler No. 10 | Natural Gas, No. 2 Fuel Oil, Hog Fuel | WESP, Multiclone, Scrubber |
| Port Townsend Paper Corporation | Package Boiler | Natural Gas | Low NOx Burner |
| PCA Wallula Mill | No. 1 Power Boiler | Natural Gas | N/A |
| PCA Wallula Mill | No. 2 Power Boiler | Natural Gas | N/A |

| | | | |
|---|---|---|---|
| PCA Wallula Mill | Hogged Fuel Boiler | Natural Gas, Hog Fuel | WESP, Overfire Air |

Despite evaluating pollution controls for 28 emission units at six pulp and paper mills, NWPPA did not find that any additional pollution controls were cost effective for these units.

The following provides general comments on the control evaluations and cost-effectiveness analyses that appear to apply to all of the NWPPA four-factor analyses and, further below, additional comments are provided that specifically apply to the controls evaluated for lime kilns and for power boilers.

*Deficiencies that Appear in All Four-Factor Analyses*

NWPPA used an interest rate of 4.8% in amortizing capital costs of most of the controls evaluated.[149] For the evaluation of low NOx burners at the power boilers, NWPPA assumed a much higher interest rate of 7%.[150] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[151] The current bank prime rate is 3.25%.[152] In a cost effectiveness analyses being done today, interest rates in the range of 4.8% to 7% are unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

1. NWPPA assumed too short of a life of pollution controls in amortizing capital costs of controls. For example. NWPPA assumed 20 years for the life of particulate matter (PM) and NOx controls, such as a wet electrostatic precipitator (WESP), improvements to existing ESPSs, and combustion control upgrades. Further, NWPPA only assumed a 15-year life for the sulfur dioxide (SO2) control of the addition of a caustic scrubber at lime kilns and for the addition of a wet scrubber to boilers. NWPPA only assumed a 10-year life for low NOx burners (LNBs). ESPs, WESPs, scrubbers, LNBs and other combustion controls should all be considered to have a life of at least 25 years. For example, in its proposed regional haze review for SO2, NOx, and PM controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls and SNCR and a 30-year life for WESPs and wet scrubbers in the cost effectiveness evaluation for these controls.[153] One just needs to evaluate how long existing controls have been in place at some of the emission units at the pulp and paper mills to know that a 25-30 year life (or more) is a much more reasonable assumption than a 15-20 year life. For example, in the Statement of Basis for the WestRock Longview Tacoma Mill, Ecology states as a description of a 2007 permitting action for replacement of a wet scrubber that the "[e]xisting scrubber is 30

[149] *Id.,* Appendix B at Tables B-1 through Table B-31.
[150] *Id.*, Appendix B at Tables B-57 through Table B-61.
[151] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[152] https://fred.stlouisfed.org/series/DPRIME.
[153] 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).

years old and nearing end of service life."[154] As another example, Recovery Furnace 22 at the WestRock Longview Tacoma Mill was constructed in approximately 1990 and equipped with an ESP, which was about 30 years ago.[155] In addition, the Georgia Pacific Camas Mill installed an ESP at Power Boiler #3 in 1992, approximately 29 years ago,[156] which is still in operation although NWPPA has indicated that the Camas Mill "does not plan to operate Boiler No. 3 going forward."[157] Thus, there are several examples of pollution controls having useful lives in the range of 25-30 years at pulp and paper mills. It is important for Ecology to require use of a realistic cost of pollution controls in amortizing capital costs of controls because the life of controls assumed has a significant impact on the annualized costs of controls, as does the interest rate.

2. NWPPA appears to use a $3,400/ton threshold to define whether pollution controls were cost-effective.[158] However, no justification has been provided for use of this cost threshold or any cost threshold for defining measures necessary to make reasonable progress, other than that NWPPA cites to the $3,400/ton cost threshold used in the Cross State Air Pollution Rule (CSAPR) for non-electrical generating units.[159] For any cost threshold selected by a state, EPA's regional haze guidance requires that the State Implementation Plan (SIP) "explain why the selected threshold is appropriate for that purpose and consistent with the requirements to make reasonable progress."[160] With respect to determining whether a pollution control is cost effective for a recovery furnace, lime kiln, or power boiler, it is important to consider the costs that similar sources have had to bear to meet Clean Air Act requirements.

   The NWPPA Four-Factor Report identifies several examples of pollution controls being installed at the pulp and paper mills evaluated in its report. For example, the burner at the lime kiln at Nippon Dynawave Packaging Company was replaced with a staged combustion natural gas burner in 2017 and the kiln no long fires fuel oil.[161] As another example, an SNCR system was installed at Power Boiler No. 20 of the WestRock Longview Mill in 2012.[162] At the WestRock Tacoma Mill, Power Boiler No. 7 has a spray tower wet scrubber installed on Power Boiler No. 7 in 2017 and low-NOx burners were installed on Power Boiler No. 6 in 2018.[163] The package boiler at Port Townshend Paper was converted to fire only natural gas using a low-NOx burner in 2016.[164] The hogged fuel boiler at the PCA Wallula Mill had an overfire air system and a WESP installed in 2016.[165] Regardless of the reasons that these controls were installed, the fact

[154] *See* Washington Department of Ecology, Statement of Basis, Air Operating Permit 0000078, WestRock Longview, LLN, December 15, 2020, at 12.
[155] *Id.* at 10.
[156] *See* Southwest Clean Air Agency, Title V Basis Statement, SW20-24-R0-A, Georgia-Pacific Consumer Operations LLC, December 17, 2020, at 7.
[157] *See* December 2019 NWPPA Report at 1-5.
[158] *Id.* at 2-12 and at 3-16.
[159] *Id.*
[160] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 39.
[161] *See* December 2019 NWPPA Report at 1-7 to 1-8.
[162] *Id.* at 1-8.
[163] *Id.*
[164] *Id.*
[165] *Id.* at 1-9.

that the controls were installed by the companies is indicative of the cost-effectiveness of the controls. Ecology should gather cost data on these control installations as well as costs of controls at other pulp and paper mills, in developing a cost effectiveness threshold for emission units at these facilities.

3. NWPPA estimated costs for certain controls based on a report from 2003. Specifically, NWPPA used cost information from the May 1, 2003 report from the National Economic Research Associates (NERA) entitled "Evaluation of Air Pollution Control Costs for the Pulp and Paper Industry."[166] Specifically, NWPPA used the cost estimates from this report to develop scaled capital cost estimates for WESPs, upgrades to ESPs, and for wet scrubbers.[167] NWPPA escalated costs from the 2003 cost basis of the NERA report to 2018 dollars using the Chemical Engineering Plant Index (CEPCI).[168] However, EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis.[169] EPA states that "[e]scalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate."[170] Further, the cost of an air pollution control does not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. Thus, Ecology should request that NWPPA obtain current retrofit cost information for these controls.

4. NWPPA included costs for sales taxes, property taxes and insurance in its capital costs of controls for several controls evaluated.[171] Yet, in many cases, property taxes do not apply to capital improvements made such as air pollutant controls, and pollution controls are not necessarily considered as increasing risks to necessitate higher insurance costs.[172] In addition, it appears that air pollution controls would be exempt from Washington sales taxes.[173] Ecology must not allow NWPPA to artificially inflate costs by items that likely would not apply to pollution control installations and upgrades.

5. NWPPA somewhat readily dismissed switching/converting to less polluting fuels, stating such fuel switches were too costly without providing sufficient detail for the assumptions of its cost analyses. Specifically, for SO2 control at recovery furnaces, NWPPA stated that the cost of switching to low sulfur No. 2 fuel oil was $12,000/ton based on a 10% capacity factor.[174] It is not clear why the assumption of only a 10% capacity factor is justified for all recovery furnaces that could switch to less polluting fuels. NWPPA did state that "some recovery furnaces are limited by their air permit to an annual heat input

[166] *Id.* at Appendix C.
[167] *Id.*
[168] *Id.*, Appendix B at Tables B-1 through B-5, B-8, B-25 through B-28, and B-31.
[169] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[170] *Id.*
[171] *See* December 2019 NWPPA Report, Appendix B at Table B-1 through B-31.
[172] *See*, e.g., EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80 (Equation 2.69). See also EPA Control Cost Manual, Section 4, Chapter 1 (SNCR), at 1-54.
[173] WAC 458-20-242A.
[174] *See* December 2019 NWPPA Report at 2-8.

of less than 10% fossil fuel…for avoidance of additional NSPS requirements."[175] However, NWPPA did not identify which of those recovery furnaces had capacity factor limitations, nor did NWPPA explain how those NSPS requirements that the facilities were avoiding with capacity factor limitations might differ if the units utilized a less polluting fuel. Yet, several units have switched from No. 6 fuel oil to No. 2 fuel or from fuel oil to natural gas, as discussed in the NWPPA report in Section 1.2.1 "Summary of Recent Emissions Reductions." Switching to lower sulfur fuel provides the least capital-intensive approach to significantly lowering SO2 emissions, and thus Ecology should not allow such fuel switches to be so readily dismissed as not cost effective without adequate documentation and justification. Indeed, other benefits of switching to less polluting fuels should also be considered in the four-factor analysis. For example, burning of natural gas requires less maintenance than the burning of fuel oil. Thus, Ecology must require that switching to less polluting fuels be more thoroughly evaluated and that any cost effectiveness evaluations be documented with data specific to each furnace or boiler for which this control is evaluated.

In addition to these general concerns that apply to NWPPA's cost effectiveness analyses, the following provides more specific comments to the cost effectiveness evaluations for lime kilns and for power boilers.

***Comments on SO2 Controls for Lime Kilns***

NWPPA states that all lime kiln SO2 emissions are low, "meaning that installing additional SO2 controls would not be cost effective."[176] The emissions presented to make this argument for each facility's lime kilns are from 2017, but NWPPA has not provided any analysis to indicate that operations and SO2 emissions from the lime kilns in 2017 are indicative of typical operating emissions. EPA's regional haze guidance for the second implementation period provides that the cost effectiveness analyses for pollution controls evaluated in four-factor analyses should be based on current emissions or projected 2028 emissions.[177] Ecology should request more information from NWPPA or the facility owners to ensure that these emissions are reflective of typical operations.

EPA stated in a 2014 document that nearly 70% of lime kilns in the pulp and paper industry are equipped with wet scrubbers.[178] Of the lime kilns that NWPPA evaluated, the WestRock Longview Mill Lime Kiln 5 had the highest SO2 emissions in 2017 and is not equipped with a wet scrubber, according to NWPPA's Four-Factor Report. Ecology should evaluate whether this lime kiln's emissions are properly characterized by 2017 data and consider evaluating the addition of a wet scrubber for SO2 control and also PM control.

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[175] *Id.*
[176] *Id.* at 2-9.
[177] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 29.
[178] U.S. EPA, Universal Industrial Sectors Integrated Solutions Model for Pulp and Paper Manufacturing Industry – Universal ISIS-PNP, November 2014, at 2-40, available at https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=311359.

***Comments on of NOx Controls Evaluations for Power Boilers***

NWPPA evaluated NOx controls for several power boilers at the six pulp and paper mills. The controls to be evaluated differed based on the fuel utilized and presumably the boiler type and existing controls. Generally, SNCR and SCR were evaluated for all boilers, and low NOx burners (LNB) were evaluated for several boilers. The following provides comments on deficiencies noted in NWPPA's NOx cost effectiveness analyses.

1. For SNCR cost evaluations, NWPPA assumed 35% control of NOx, regardless of the NOx inlet rate to the SNCR system.[179] NWPPPA did not provide any justification for that assumption. EPA's Control Cost Manual indicates NOx removal efficiencies for SNCR used at boilers in the pulp and paper industry as achieving a median NOx removal efficiency of 50% with urea used as the reagent with a range of 20-62%.[180] EPA also stated that median NOx reductions with ammonia-based SNCR systems are 61-65% and that most boilers with ammonia-based SNCR systems that are solid fuel-fired are fired with wood or municipal solid waste.[181] Thus, NWPPA has greatly underestimated the NOx reduction capabilities and cost effectiveness of SNCR by only assuming 35% NOx control.

2. NWPPA used EPA's SNCR cost calculation spreadsheet made available with its Control Cost Manual.[182] For the SNCR control evaluations, NWPPA assumed a 1.5 retrofit factor, which essentially increases capital costs by a factor of 1.5. NWPPA states that "the costs algorithms [of EPA's cost spreadsheet] were developed based on project costs for large coal-fired utility boilers" and assumed, without providing any further justification that EPA's cost algorithms "likely underestimate costs for smaller industrial boilers." Thus, NWPPA applied a retrofit factor of 1.5 "to account for the need to add multiple levels of injectors and perform additional tuning of the system across loads."[183] This was not a justified cost increase. EPA's Control Cost Manual chapter on SNCR costs states there is very little difference in the costs to retrofit SNCR to existing boilers compared to new boilers.[184] EPA's SCNR cost spreadsheet states that it can be used for industrial boilers with maximum heat input capacities of 250 MMBtu/hour or greater and, while EPA has acknowledged that capital costs increase for smaller boilers, the costs do not increase by 50% except for very small boilers.[185] Thus, Ecology should not allow use of any retrofit factor for SNCR costs at any of the power boilers without sufficient documentation from NWPPA or the facility owners to justify the use of a retrofit factor.

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[179] *See* December 2019 NWPPA Report at 3-8 and 3-10.
[180] EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-2, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[181] *Id.* at 1-1.
[182] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[183] *See* December 2019 NWPPA Report at 3-20.
[184] EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, 4/25/2019, at 1-6.
[185] *Id.* at 1-7 (Figure 1.2).

3. NWPPA used EPA's SCR cost calculation spreadsheet made available with its Control Cost Manual.[186] EPA's SCR cost spreadsheet already provides a 20% retrofit factor for SCR retrofits as compared to SCR installation costs on a new facility.[187] In addition, the cost algorithms in EPA's SCR cost spreadsheet are based on the average SCR retrofit costs for utility boilers, which often have retrofit difficulties and additional costs, especially due to the large sizes of the SCR reactors and the need for specialized cranes to maneuver large SCR reactors into tight or elevated spaces. Thus, some retrofit difficulty is already built into the costs of EPA's SCR cost spreadsheet. NWPPA did not provide adequate justification for its application of a 1.5 retrofit factor to SCR cost analyses for power boilers. NWPPA simply said "[a] retrofit factor of 1.5 was applied to all industrial boilers since the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, and the likelihood of needing a new ID fan to account for increased pressure drop."[188] Ecology must not allow use of retrofit factors in the SCR cost analyses unless justified based on the specific situation for a particular power boiler.

4. NWPPA did not provide data on the assumptions that went into the cost effectiveness of SCR or SNCR for the power boilers. For example, NWPPA's four-factor submittal does not identify the baseline NOx emissions and emission rates of each boiler in tons per year and lb/MMBtu. It also did not identify the operating hours and/or operating capacity factor of each power boiler used in estimating the operational expenses of these controls. In addition, NWPPA did not identify specific costs assumed for the SNCR and SCR reagent (including what type of reagent was assumed) or the electricity costs. It also is not clear what unit characteristics and fuel characteristics were assumed in the cost spreadsheets for each boiler. Had NWPPA provided a printout of all pages of EPA's SNCR and SCR spreadsheets in its four-factor report, this information could be evaluated. Thus, Ecology must ask NWPPA to make all of the pages of the SNCR and SCR spreadsheets available for review for the power boilers.

   It must be noted that the calculated NOx emission reductions for SNCR and SCR seem inconsistent with the baseline emissions assumed for the boilers evaluated for LNB control. Specifically, one can back-calculate the assumed uncontrolled emissions for a boiler by dividing the NOx reductions presented in the spreadsheet printouts for SNCR and SCR by the assumed 35% (for SNCR) and 90% (for SCR) NOx removal efficiency. When we back-calculated those uncontrolled NOx emission rates for the five power boilers that were evaluated for LNB controls (i.e., Nippon Dynawave Boilers 6, 7, and 9 and PCA Wallula Boilers 1 and 2), we found the resulting "uncontrolled NOx emissions" assumed in the SNCR and SCR analyses for these boilers were about 55% higher than the uncontrolled NOx emissions assumed for these units in the LNB cost analyses.[189] Ecology should further evaluate these emission calculations to ensure consistency across

[186] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[187] This is evident by the fact that if one enters in the Data Inputs tab that the SCR is for a new boiler, the retrofit factor drops from 1 to 0.8.
[188] *See* December 2019 NWPPA Report at 3-22.
[189] *Id.*, Appendix B at Tables B-57 through Table B-61. The LNB cost analyses for these power boilers identify baseline NOx emissions.

all analyses, and to ensure that the baseline NOx emissions truly reflect actual baseline emissions for the power boilers. Having NWPPA submit the entire spreadsheets for these cost calculations would greatly help in ensuring consistency and accuracy of the cost effectiveness calculations.

5. For the analysis of LNBs, NWPPA used a John Zink cost analysis from 2016 for a 99 MMBtu/hr gas-fired boiler.[190] For this analysis, NWPPA inexplicably assumed a 7% interest rate rather than the 4.7% interest rate it assumed for its other cost analyses.[191] As discussed above, there is no justification for such a high interest rate, and Ecology should make sure the current prime rate be used in cost analyses, to be consistent with EPA's Control Cost Manual. In addition, NWPPA's cost effectiveness analyses of LNB for power boilers assumed LNBs would only have a life of 10 years.[192] Low NOx burners should have a useful life of 25-30 years or more. In evaluations of best available retrofit technology (BART) for natural gas and oil-fired utility boilers, EPA evaluated combustion controls such as low NOx burners and SCR at lifetimes of 30 years.[193] Thus, NWPPA was not justified in assuming such a short lifetime of LNB and such a high interest rate, and these invalid assumptions improperly made LNB appear to be less cost effective.

It is also questionable whether NWPPA's assumption of only 50% NOx reductions with LNB is a reasonable estimate of achievable emission reductions with LNB. EPA states that NOx emission reductions of 40 to 85% are achievable with low NOx burners.[194] In addition, NWPPA did not evaluate flue gas recirculation (FGR) in combination with LNB. EPA states that these controls are normally used together to reduce NOx, and emission reductions of 60 to 90% are achievable.[195] Indeed, the No. 5 Power Boiler at the Georgia Pacific Camas Mill is equipped with these controls.[196] Ecology must ensure that NWPPA evaluates the most effective combustion controls for the power boilers.

It is important to note that just revising the annualized capital costs of LNBs using NWPPA's cost numbers but using a capital recovery factor reflective of a 3.25% interest rate and a 25-year life makes a significant difference in the cost effectiveness of LNBs at the power boilers, as the table below demonstrates.

[190] *Id.* at 3-22.
[191] *Id.*, Appendix B at Tables B-57 through Table B-61.
[192] *Id.*
[193] *See*, e.g., EPA's proposed action on Arkansas' Regional Haze Implementation Plan in which EPA assumed a 30-year life for combustion controls including LNB, SNCR, and SCR at a 30-year life for a natural gas- and oil-fired power plant, Bailey Unit 1, and the natura gas- and oil-fired McClellan power plant. 80 Fed. Reg. 18944 at 18953, 18960 (Apr. 8, 2015).
[194] EPA, AP-42 Emission Factor Documentations, Section 1.4 Natural Gas Combustion, at Section 1.4.4, available at https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.
[195] *Id.*
[196] *See* December 2019 NWPPA Report at 3-13.

**Figure 4. Revisions to NWPAA's Cost Effectiveness of LNBs at Power Boilers to Use a Lower Interest Rate and a More Realistic Life of LNB Controls (3.25% Interest Rate, 25-Year Life of LNB)**

| Plant-Unit | Total Annualized Costs (at 3.25% Interest and 25 Year Life) | NOx reductions (per NWPPA), tpy | Revised Cost Effectiveness (at 3.25% Interest Rate and 25-Year Life) | NWPPA's Cost Effectiveness (at 7% Interest Rate and 10-Year Life) |
|---|---|---|---|---|
| Nippon Dynawave Boiler 6 | $141,708 | 18.55 | $7,639 | $12,093 |
| Nippon Dynawave Boiler 7 | $168,795 | 28 | $6,028 | $9,543 |
| Nippon Dynawave Boiler 9 | $250,813 | 97.3 | $2,578 | $4,081 |
| PCA Wallula Boiler 1 | $142,579 | 25.85 | $5,516 | $8,732 |
| PCA Wallula Boiler 2 | $136,856 | 30.3 | $4,517 | $7,162 |

As the Figure 4 demonstrates, the use of an unreasonably high interest rate and an unreasonably low useful life of controls can greatly distort the cost effectiveness of controls. Not only do revisions to the cost effectiveness analyses to reflect appropriate interest rates and life of controls improve the cost effectiveness of LNB, but such revisions would also improve the cost effectiveness of SNCR and SCR for the power boilers. Moreover, if more realistic levels of NOx reduction were assumed with LNB and also with SNCR, those controls would likely be more effective. Further, as previously stated, no retrofit factor was justified to the SNCR costs or the SCR costs and revising the costs to eliminate the retrofit factor applied would also make those controls more cost effective. Indeed, with these revisions made, it is likely that LNB and/or SNCR would be considered very cost effective for several of the power boilers at the pulp and paper mills. Further, a review of the cost inputs used in the SCR cost analyses is imperative to ensure that costs for items such as reagent, electricity, or catalysts were not overstated in those analyses. Ecology must thus obtain more information on the cost analyses done and require revisions to those analyses to address the above issues, before making a determining on the most cost-effective controls for the power boilers at the pulp and paper mills evaluated by NWPPA.

## VII. Comments on Four-Factor Analyses for the Cosmo Specialty Fibers Mill

Cosmo Specialty Fibers (Cosmo) operated a sulfite pulp mill located in Cosmopolis, Washington. A four-factor analysis was submitted for controls at one emissions unit at the plant:

the hog fuel boiler at the facility.[197] Cosmo did not provide four-factor analyses for the recovery boilers at the facility (Recovery Boiler 1, 2, and 3), nor did Cosmo provide four-factor analyses for the hogged fuel dryer at the facility. Ecology should require that Cosmo provide a four-factor analysis of controls for those emission units.

Cosmo relied on Ecology's 2016 analysis entitled "Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills" dated November 2016 to justify no additional regional haze controls for its recovery boilers.[198] However, the November 2016 Ecology RACT analyses was focused on whether the visibility benefits of pollution controls evaluated justified the costs of the pollution controls. As discussed in Section I.C., the visibility benefits of controls are not part of the Clean Air Act's four-factor analysis; thus, Ecology's determination should not add an additional factor to the four statutory factors. It must also be pointed out that Ecology's 2016 RACT analysis was based on emission inventories between 2003 to 2011 and, as noted in the 2016 RACT analysis, Cosmo did not operate from 2007-2010.[199] In fact, a support document for a Title V permit for the Cosmo facility states that when the Cosmo mill restarted in 2011, it had eliminated two processes (cellophane and paper grade production) and only produced dissolving pulp.[200] That basis statement also stated that "[p]roduction varies upon market demand."[201] Thus, Ecology's 2016 report did not have much emissions data reflective of the new operations at the Cosmo facility to base a cost effectiveness analysis of pollution controls on, and a revised analysis of pollution controls must be done for these emission units reflective of current emissions that reflect expected operations in 2028. For these reasons, Ecology's 2016 RACT analysis must not exempt a facility from evaluating pollution controls for any part of its facility.

Cosmo evaluated SCR and SNCR for NOx controls at the hog fuel boiler and evaluated use of an ESP to reduce PM emissions from the hog fuel boiler. Cosmo determined that no additional controls are required at the hog fuel boiler to address regional haze requirements.[202]

*Deficiencies in Cosmo's cost effectiveness analyses*

1. Cosmo assumed a 4.75% interest rate in amortizing capital costs of the controls evaluated.[203] In its Control Cost Manual, EPA states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[204] The current bank prime rate is 3.25%.[205] In a cost effectiveness analyses being done today, an interest rate of

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[197] December 2019 Four-Factor Analysis for Cosmo Specialty Fibers (hereinafter referred to as "Cosmo Four-Factor Analysis").
[198] *Id.* at 3-1.
[199] Washington Department of Ecology, Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills, November 2016, at 34.
[200] Support Document for the Air Operating Permit issued to Cosmo Specialty Fibers, [undated], at 4.
[201] *Id.*
[202] *See* Cosmo Four-Factor Analysis at 1-1.
[203] *Id.*, Appendix B, Tables 1b, 2b, and 3b.
[204] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[205] https://fred.stlouisfed.org/series/DPRIME.

4.75% is unreasonably high, given the current bank prime lending rate of 3.25%. Use of a higher interest rate results in higher annualized capital costs.

2. Cosmo assumed too short of a life of pollution controls in amortizing capital costs of controls. Cosmo only assumed a 20-year life in its cost effectiveness evaluations for SCR, SNCR, and ESP.[206] EPA's SCR chapter of its Control Cost Manual indicates that the life of SCR at industrial boilers would be 20-25 years.[207] As stated above in the comments on the NWPPA facilities, a simple review of pollution controls at existing boilers and furnaces in the pulp and paper industry shows that pollution controls like ESPs are in place for 25 to 30 years or more. For example, Recovery Furnace 22 at the WestRock Longview Tacoma Mill was constructed in approximately 1990 and equipped with an ESP, which was about 30 years ago.[208] Further, the Georgia Pacific Camas Mill installed an ESP at Power Boiler #3 in 1992, approximately 29 years ago.[209] Thus, a 25-30 year life is likely a more appropriate life of controls to use in amortizing capital costs of a pollution control for the hog fuel boiler. In its proposed regional haze review for SO2, NOx, and PM controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls and SNCR and a 30-year life for WESPs and wet scrubbers.[210] It is important for Ecology to require use of a realistic cost of pollution controls in amortizing capital costs of controls, because the life of controls assumed has a significant impact on the annualized costs of controls, as does the interest rate.

3. In the evaluation of SNCR for NOx control, Cosmo only assumed 25% NOx control would be achieved.[211] Cosmo stated this lower NOx control efficiency was applied due to the "load-swing nature of the Hog Fuel Boiler as well as low NOx concentration…."[212] Ecology should request more information from Cosmo on the load-swing nature of the boiler and how that could impact NOx removal efficiency with SNCR. The hog fuel boiler does appear to run throughout the year, as Cosmo stated the typical operating level of the unit was 357 days per year at 24 hours per day.[213]

4. In the evaluation of SCR for the hog fuel boiler, Cosmo assumed that the flue gas would need to be reheated and Cosmo took into account estimated costs to reheat the flue gas in the SCR cost effectiveness analysis.[214] The cost for reheating the flue gas reflects 85 to 88% of Cosmo's total annual costs of SCR.[215] Cosmo did not provide the detailed

[206] Cosmo Four-Factor Analysis, Appendix B at Tables 1b, 2b, and 3b.
[207] EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[207] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 80.
[208] *Id.* at 10.
[209] *See* Southwest Clean Air Agency, Title V Basis Statement, SW20-24-R0-A, Georgia-Pacific Consumer Operations LLC, December 17, 2020, at 7.
[210] 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).
[211] Cosmo Four-Factor Analysis at 4-6.
[212] *Id.*
[213] *Id.* at 4-6 (Table 4-2).
[214] *Id.* at 4-6.
[215] *Id.*

calculations to verify the costs for reheating the flue gas stream, and Ecology must request that data.

5. Cosmo did not evaluate the cost effectiveness of a high dust SCR system which would eliminate any need for flue gas reheating, thus reducing Cosmo's annual cost estimates of SCR significantly. Cosmo's justification for not evaluating a high dust SCR was concerns about particulate emissions poisoning the SCR catalyst.[216] However, there are options to reduce or slow down catalyst deactivation that should have been considered. One study on this issue states that SCR catalyst deactivation in biomass fired plants is mostly due to high potassium content in biomass and that one method to deal with that is potassium removal by adsorption.[217] This paper states that addition of alumino silicates, in the form of coal fly ash, is an "industry proven method of removing [potassium] aerosols from flue gases."[218] Other options to address this concern (aside from tail-end SCR that requires reheating of the flue gas) include the coating SCR monoliths with a protective layer and the use of potassium tolerant SCR catalysts.[219] Ecology must request that Cosmo evaluate these other options to accommodate a high dust SCR configuration, which could ultimately end up being a very cost effective and highly effective NOx control.

6. For the ESP evaluated by Cosmo for the hog fuel boiler, Cosmo included costs for property taxes and insurance.[220] Yet, as discussed above, in many cases, property taxes do not apply to capital improvements made such as air pollutant controls, and pollution controls are not necessarily considered as increasing risks to necessitate higher insurance costs.[221] Ecology must not allow NWPPA to artificially inflate costs by items that likely would not apply to pollution control installations and upgrades.

There are examples of similar emission units in the pulp and paper industry in Washington that have installed both NOx and PM controls. For example, the hogged fuel boiler at the PCA Wallula Mill had a WESP installed in 2016.[222] In addition, an SNCR was installed at the WestRock Longview Power Boiler 20,[223] which appears to be a similar boiler to the hog fuel boiler at the Cosmo plant, in that the WestRock Longview Power Boiler 20 burns wood fuels (hog fuel, forest biomass, urban wood) and oil (including reprocessed fuel oil), as well as burning paper recycling residuals, primary/secondary sludge from the process wastewater treatment plant, and natural gas.[224] Power Boiler 20 is described as a "hybrid suspension grate boiler designed to fire wet biomass…."[225] Ecology should further evaluate the SNCR installed at the WestRock Longview Power Boiler 20 to determine the percent NOx removal being achieved

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[216] *Id.*
[217] *See* Schill, Leonhard and Rasmus Fehrmann, Strategies of Coping with Deactivation of NH3-SCR Catalysts Due to Biomass Firing, March 30, 2018, available at https://www.mdpi.com/2073-4344/8/4/135/htm.
[218] *Id.*
[219] *Id.*
[220] *Id.* at Appendix B, Table 3a.
[221] *See*, e.g., EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80 (Equation 2.69). *See also* EPA Control Cost Manual, Section 4, Chapter 1 (SNCR), at 1-54.
[222] *See* December 2019 NWPPA Report at 1-9.
[223] *Id.*
[224] Washington Department of Ecology, Statement of Basis for Air Operating Permit 0000078, WestRock Longview, December 15, 2020, at 42.
[225] *Id.*

at that unit to assess SNCR NOx removal capabilities for the hog fuel boiler at the Cosmo facility. Because a similar source has found it cost effective to install SNCR to reduce NOx emissions, that provides a strong basis to consider SNCR as a cost-effective control for the Cosmo hog fuel boiler. Note that the Title V statement of basis for the WestRock Longview plant indicates that the SNCR was installed at the WestRock Longview Power Boiler 20 to reduce NOx emissions as part of Order 8429 which allowed for higher solid fuel firing rate.[226] Thus, the SNCR was likely installed to allow the increased solid fuel firing rate at WestRock Longview Boiler 20 to "net out" of major source permitting requirements. Controls installed to net out of major source permitting requirements should be considered controls required under the Clean Air Act. Such controls provide a relevant example of a source determining it was cost-effective to install the pollution control, even if the reasoning was to avoid a more substantive Clean Air Act requirement.

## VIII. Comments on Ecology's Proposed Recommendations for the Chemical Pulp & Paper Industry

For the pulp and paper facilities, Ecology found that some controls at certain facilities are cost effective, but then has proposed to find that no controls were justified based on modeling that was done for its 2016 NOx RACT analysis.[227] Ecology points to a statement in the 2019 EPA Regional Haze Guidance which states that "a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility improvement."[228] While Ecology acknowledges that the combination of many small improvements in visibility can add up to a visibility benefit for Class I areas, it found that "control measures for the pulp mills do not appear necessary to meet the reasonable progress goals during this implementation period and would not provide meaningful visibility improvement…."[229]There are both legal and technical problems with Ecology's reasoning. As discussed above in Section II.C., Ecology's consideration of modeling results as a fifth-factor is inconsistent with the Act's four-factor reasonable progress analysis requirement.

With respect to the technical arguments, Ecology relies on its 2016 RACT analysis for the pulp and paper industry for which Washington State University (WSU) did a modeling analysis of potential RACT controls.[230] The 2016 RACT analysis only evaluated controls for recovery furnaces/boilers and lime kilns, and the modeling only focused on PM and SO2 emission reductions.[231] No reductions in NOx emissions were modeled. Further, the modeling was based on emission reductions from a 2007 baseline,[232] which is out of date and not necessarily reflective of emissions from these plants in 2028. Ecology is not justified in relying

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[226] *Id.* at 43.
[227] *Id.* at 39.
[228] *Id.* a 37.
[229] *Id.*
[230] *Id.* at 37.
[231] *See* November 2016 Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills, Appendix C at 150.
[232] *Id.,* Appendix C at 147.

on such out-of-date modeling that did not even model NOx reductions or even consider emission reductions at power boilers in making any claims about the visibility benefits of further emissions controls at the pulp and paper industry. Further, the scale of emission reductions that could be achieved with SCR or SNCR at the power boilers, which Ecology claims would be cost effective for several units, is much greater than the scale of emission reductions modeled in the 2016 study.

One of the facilities that Ecology stated could cost-effectively install SCR or SNCR at two boilers was the Nippon Dynawave facility, for which Ecology estimated would reduce NOx emissions by 500 to 1,025 tons of NOx per year with the high end of emission reductions presumably reflecting installation of SCR.[233] Relying on the 2016 modeling which, according to Ecology, modeled reductions in SO2 and PM of 1,345 tons per year,[234] Ecology assumed that reducing NOx by approximately 1,125 tons per year at the Nippon Dynawave facility along with reductions of about 200 tons per year in NOx and PM10 at a few other facilities would only achieve similar visibility benefits that were shown in the 2016 modeling analysis, which purportedly predicted at maximum a visibility benefit of 0.127 deciviews. Not only are the 2016 modeling results out of date, the results of the 2016 analyses are not comparable because no NOx emission reductions were modeled and because no emission reductions from the Nippon Dynawave facility (formerly part of the Weyerhaeuser NR facility) were modeled.[235]

Thus, if it was appropriate to rely solely on modeled visibility benefits to justify not considering cost-effective controls for emission units at pulp and paper facilities in the state's regional haze plan for the second implementation period, which we contend is not appropriate, the modeling that Ecology is planning to rely on fails to provide any analysis of Ecology's finding of cost-effective emission reductions, particularly in emissions of NOx. The 2016 modeling cannot be considered as a technically sound basis for finding that no additional NOx controls are justified for the emission units at any of Washington's pulp and paper facilities.

## IX. Comments on Four-Factor Analyses for Ash Grove Cement Company

The Ash Grove Cement Company operates a cement kiln in the Seattle area. According to Ecology, its 2014 NOx emissions were 1,144 tons per year based on 2014 emissions.[236] In 2017, its NOx emissions were much higher at 1,367.9 tons per year.[237] Thus, the facility is a large source of NOx. Based on 2017 emissions and considering Class I areas in which the facility had a Q/d equal to or greater than 5, we calculate a cumulative Q/d of the Ash Grove Cement Company as 135.8.

[233] Draft Chapter 11 at 34.
[234] *Id.* at 35.
[235] Appendix C at 150 (Table C.3.).
[236] Washington Department of Ecology (WDOE), Draft Regional Haze SIP Revision – Second 10-Year Plan, Chapter 11 ("WDOE Draft SIP Revision, Chapter 11"), at 11.
[237] Data from EPA's National Emissions Inventory for 2017.

Ecology has proposed no additional NOx controls for this cement plant, claiming technical infeasibility for SCR and SNCR in large part based on space constraints.[238] However, space constraints should not be an issue for SNCR. The EPA describes the SNCR process as "injecting an ammonia type reactant into the furnace at a properly determined location" and EPA lists cement kilns as among the "multitude of combustion sources" at which SNCR has been utilized.[239] EPA states that the "mechanical equipment associated with an SNCR system is simple compared to an SCR" and that "[i]nstallation of SNCR equipment requires minimal downtime."[240] EPA also states that it does not expect substantial differences in costs to retrofitting SNCR to an existing source compared to the cost to install it with the construction of a new source, based on evaluation of costs of SNCR installations in the 1990's.[241] Thus, for all of these reasons, retrofit difficulty and/or space constraints should not be an issue for SNCR installation.

Ecology also implies that SNCR systems cannot be installed in the high temperature zone before the particulate controls. [242] However, that is not correct. Because there is no catalyst with an SNCR system, the reagent is injected in the combustion zone and high dust concentrations in the exhaust are not an issue for effective operation. Thus, Ecology's claims of retrofit difficulty due to space and of the need to reheat the exhaust stream for effective SNCR operation are without merit.

Ecology states that, in August 2016, the PSCAA approved a NOx limit of 5.1 lb NOx per ton of clinker.[243] This NOx limit was apparently developed a 2013 Consent Decree with the Ash Grove Cement Company, but that Consent Decree only required the optimization of the operation of the cement kiln at the Seattle plant to reduce NOx emissions.[244] Ecology left out that the 2013 Consent Decree with Ash Grove Cement Company required SNCR installation at several Ash Grove Cement Company plants.[245] It is not clear why the Seattle facility was not required to install SNCR, but it is clear that SNCR has been installed to control NOx at several of the company's cement kilns. The lowest NOx limit required for cement kilns with SNCR in the Consent Decree was 1.5 lb NOx per ton of clinker. This same emission limit has also been imposed to meet BACT, based on installation of SNCR and combustion controls.[246] Such a limit would reflect a reduction in emissions of 70.6% on a lb NOx per ton of clinker basis. The Seattle Ash Grove Cement facility had NOx emissions of 1,144 tons per year in 2014,[247] thus a 70.6% reduction would equate to 807.7 tons per year of NOx reduced from 2014 levels.

[238] WDOE Draft SIP Revision, Chapter 11 at 18.
[239] EPA, Control Cost Manual, Selective Noncatalytic Reduction, at 1-1.
[240] *Id.* at 1-6.
[241] *Id.*
[242] WDOE Draft SIP Revision, Chapter 11 at 18.
[243] *Id.* at 17.
[244] 2013 Consent Decree, *United States et al. v. Ash Grove Cement Company*, (No. 2:13-cv-02299-JTM-DJW) at 25 (¶21), available at https://www.epa.gov/sites/production/files/documents/ashgrove-cd.pdf. ("Exhibit 4," attached)
[245] *Id*. at ¶¶ 13, 15, 17, 19, 24, 25, 27, and 30.
[246] *See* Georgia Environmental Protection Division Permit No. 3241-153-0075-P-01-0 for US Cement, LLC, issued 6/29/2020, at 1 and at 15, available at https://permitsearch.gaepd.org/.
[247] WDOE Draft SIP Revision, Chapter 11, at 11.

Given that several similar sources have installed SNCR to meet Clean Air Act requirements, the costs of SNCR at the Seattle Ash Grove Cement facility would very likely be cost effective. Ecology should not have dismissed SNCR as technically infeasible. SNCR could readily work with whatever combustion optimization procedures the company put into place to comply with the Consent Decree. Ecology thus should not have excluded SNCR from review in a four-factor analysis for the Ash Grove Cement Plant.

## X. Comments on Ecology's Draft Chapter 10 Long-Term Strategy for Visibility Impairment

Ecology's draft long-term strategy states that it "relied on the Western Regional Air Partnership (WRAP) for air quality modeling and other analytical tools to identify pollutants, the sources of those pollutants, and to predict future levels of visibility impairment."[248] Ecology also states "[t]hrough WRAP technical collaborations, the western states agreed upon the [reasonable progress goals (RPGs)] set for 2028 and a regionally consistent approach to addressing visibility impairment in the West."[249] First, the RPGs are not to be developed before the four-factor analyses but as a result of the four-factor analyses.[250]

Second, while the western states may have agreed on the modeling (and presumably the emission inventory development) compiled or completed by the WRAP, the general public has not had the opportunity to review and comment on the assumptions that went into the emission inventories or the modeling. The regional haze regulations require the long term strategy to "document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects."[251] While the regional haze rule allow states to meet this requirement "by relying on technical analyses developed by the regional planning organization and approved by all State participants."[252] As part of its proposed SIP revisions, Ecology must not only follow the requirements in the RHR, but also the requirements for preparation, adoption and submittal of SIPs (i.e., 40 C.F.R. §§ 51.100, 51.102, 51.103, 51.104, 51.105 and Appendix V to Part 51. Ecology has an obligation to make transparent and cite to (and provide weblinks to) the technical support documentation it proposes to rely on and use as part of its SIP revision (e.g., such regional planning organization technical analyses) and provide the public with the opportunity to comment on such analyses. Thus, Ecology must cite to and provide weblinks to the WRAP's documentation and analysis for the emissions information, monitoring and modeling.[253]

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248 WDOE Draft Chapter 10, at 3.
249 *Id.*
250 *See*, e.g., 82 Fed. Reg. 3090-91 (Jan. 10, 2017).
251 40 C.F.R. 51.308(d)(3)(iii).
252 *Id*
253 40 C.F.R. Part 51, Appendix V ¶ 2.2 Technical Support. "(a) Identification of all regulated pollutants affected by the plan. (b) Identification of the locations of affected sources including the EPA attainment/nonattainment

The regional haze rule requires that "[t]he State must identify the baseline emissions inventory on which its strategies are based."[254] Except for the facilities for which it conducted four-factor analyses, Ecology has not provided its baseline emission inventory of all visibility-impairing pollution from the various sources within its state. Ecology must provide that information with the long-term strategy for public review and comment. Given that the state is relying on federal, state, and local rules regarding mobile onroad engines, nonroad engines, marine engines, fuel sulfur limitations, petroleum refinery maximum achievable control technology (MACT), boiler MACT, revised utility boiler MACT, various area source MACT, industrial/commercial boiler burning designated solid wastes NSPS, sewage sludge incinerator NSPS, ozone and PM10 SIPs, state oil and gas emission control programs, the 2010 SO2 and NO2 NAAQS, the 2013 PM2.5 NAAQS, and the 2015 ozone NAAQS,[255] it is important that Ecology provide a baseline emissions inventory for these various source categories so that the public can evaluate the emission reductions that are being proposed as part of Washington's long-term strategy.

In its discussion of state, federal and local rules and controls that limit visibility-impairing pollutants, Ecology states "[o]f special importance are federal fuel and engine rules for on-road and nonroad engines. These result in large projected percent decreases in visibility-impairing emissions in Washington by 2028."[256] Ecology's draft long-term strategy chapter states that information will be added regarding the percentage reduction due to these rules. We request that Ecology document the technical basis for the assumed emission reductions in nonroad engines, as required by 40 C.F.R. 51.308(d)(3)(iii). The nonroad engine requirements in 40 C.F.R. Parts 89 and 1039 require manufacturers to only make engines meeting certain specified emission standards with the most stringent Tier 4 emission standards applying in approximately 2014 and beyond. However, the federal rules do not require companies to use these cleaner burning engines. It is not clear whether Washington State or local rules require companies to replace existing engines with these cleaner burning engines. Similarly, while ultra-low sulfur diesel fuel has been available since about 2006 and has been required by diesel

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designation of the locations and the status of the attainment plan for the affected areas(s). (c) Quantification of the changes in plan allowable emissions from the affected sources; estimates of changes in current actual emissions from affected sources or, where appropriate, quantification of changes in actual emissions from affected sources through calculations of the differences between certain baseline levels and allowable emissions anticipated as a result of the revision. (d) The State's demonstration that the national ambient air quality standards, prevention of significant deterioration increments, reasonable further progress demonstration, and visibility, as applicable, are protected if the plan is approved and implemented. …. (e) Modeling information required to support the proposed revision, including input data, output data, models used, justification of model selections, ambient monitoring data used, meteorological data used, justification for use of offsite data (where used), modes of models used, assumptions, and other information relevant to the determination of adequacy of the modeling analysis. (f) Evidence, where necessary, that emission limitations are based on continuous emission reduction technology. (g) Evidence that the plan contains emission limitations, work practice standards and recordkeeping/reporting requirements, where necessary, to ensure emission levels. (h) Compliance/enforcement strategies, including how compliance will be determined in practice. (i) Special economic and technological justifications required by any applicable EPA policies, or an explanation of why such justifications are not necessary."

[254] *Id.*

[255] WDOE Draft Chapter 10 at 5-7

[256] *Id.* at 6.

manufacturers since 2014, there are exemptions for older locomotive and marine engines.[257] Thus, Ecology should provide the technical basis for assumed emission reductions from nonroad engines in Washington state, both due to use of lower-emitting engines and use of lower sulfur fuel. To the extent the assumptions regarding emission reductions from nonroad engines were developed by the WRAP, Ecology should document the WRAP's assumptions and provide links to the underlying documentation so that the public can have the opportunity to review and comment on it. Finally, if Ecology is relying on federal rules for future emission projections, Ecology must also document its assumptions, provide citations to the federal rules it relies on, and if enforceable measures are necessary, include them in the proposed SIP revision.

Ecology identifies several control strategies that were not in the previous Regional Haze SIP that apply at the Federal and/or State level. Ecology states that the most current emission inventory reflects several of these rules, including the following:[258]

- MARPOL V
- The North American Emission Control Area (ECA) for marine vessels
- The marine vessel fuel sulfur standard
- NAAQS revisions since 2007

Ecology should document the extent to which emission reductions have actually occurred as a result of these regulations and requirements. For example, for the sulfur standard for marine vessels, Ecology acknowledges that EPA and the U.S. Coast Guard have allowed some shipping companies delayed compliance dates with these requirements.[259] Ecology should document the extent to which shipping companies doing business in Washington state are complying with these standards or whether such companies have been granted a delay in compliance and, if so, how long compliance has been delayed. It appears that the MARPOL V requirements are applicable to marine engine manufacturers pursuant to 40 C.F.R. Part 90, but the requirements do not require that shipping companies use those engines. Further, the EPA recently proposed regulations on marine engines that would weaken emission standards and sulfur in fuel standard.[260] Thus, we request that Ecology identify the extent to which the lower-emitting engines are being utilized by shipping companies doing business in Washington state. Ecology states that "[t]he effects of the marine vessel fuel sulfur requirements are reflected in the IMPROVE data, though the effect of the [North American Emissions Control Area (ECA)] are not fully reflected in the data due to the long lead time for the MARPOL requirements and the relatively recent date (2013) for vessels to meet the first stage requirements."[261] We request that Ecology also document the extent to which emission reductions associated with these programs have been reflected in the emissions inventories modeled by the WRAP and the extent to which any such modeled emission reductions were ground-truthed. Finally, if Ecology is relying on federal rules for future emission projections, Ecology must also document its assumptions,

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[257] *See* https://www.epa.gov/diesel-fuel-standards/diesel-fuel-standards-and-rulemakings.
[258] WDOE Draft Chapter 10, at 7.
[259] *Id.*
[260] 84 Fed. Reg. 46909, Sept. 6, 2019.
[261] WDOE Draft Chapter 10, at 7.

provide citations to the federal rules it relies on, and if enforceable measures are necessary, include them in the proposed SIP revision.

With respect to mobile sources, Ecology states that Washington's vehicle emissions testing program was phased out by the legislature "based on Ecology's prediction that more fuel efficient and electric vehicles would replace the need for it by 2020…."[262] Ecology also discusses the Washington legislature's adoption of California vehicle emission standards for passenger cars, light duty trucks and medium duty passenger vehicles. Ecology should provide more documentation as to when these provisions took effect (or when the provisions will take effect) in the state. Ecology should also discuss whether and how the Trump administration's decision to revoke California's waiver under the Clean Air Act to impose more stringent emission standards may have impacted this emission reduction strategy in Washington state.

For the emission reductions due to NAAQS revisions since 2007, the state identified the 2010 NOx NAAQS, the 2010 SO2 NAAS, the 2013 PM2.5 NAAQS, and the 2015 ozone NAAQS. Ecology should identify rules/emission standards and requirements that it has adopted to require emission reductions to comply with these NAAQS and when compliance was or will be required. Ecology should also make clear whether any area in Washington state has been or will be designated as nonattainment for any of these NAAQS and whether additional NAAQS control requirements will be forthcoming in the state. The long-term strategy is supposed detail the enforceable emission limitations and compliance timeframes.[263] Thus, Ecology's plan must include more details on the NAAQS requirements that it relies on for future emissions controls.

## XI. Ecology Should Analyze the Environmental Justice Impacts of its Regional Haze SIP, and Ensure the SIP Will Minimize Harms to Disproportionately Impacted Communities

In Seattle, 13 of the 14 heaviest industrial polluters are located within a half-mile of the places where marginalized communities live, work, play, and worship in Seattle. Of the 20 biggest regional haze producing facilities in Washington, two of them are located in the Duwamish Valley – Ash Grove Cement and Ardagh Glass.

Ardagh's facility has had a long history of violations in addition to inadequate or lack of required emissions reporting. Ardagh's glass melting furnaces emit quantities of SO2 and NOx that place it in the "major source" Air Operating Permit program, and also significant qualities of total particulate matter (PM). For the last decade or more, the annual levels of fine particulate matter at the E. Marginal Way S (Duwamish) monitor in the industrial area, that includes Ardagh, have been higher than any monitor in the Puget Sound Clean Air Agency (PSCAA) four-county area.

The Duwamish Valley's riverfront neighborhoods Georgetown and South Park are situated within two miles of the Ardagh Glass facility and have long been disproportionately

[262] *Id.* at 9.
[263] 40 C.F.R. 51.308(d)(3).

exposed to contamination, cumulative environmental injustices, and subsequent adverse health-related outcomes. Residents who Georgetown and South Park have some of the highest health discrepancies in the City of Seattle. Childhood asthma hospitalization rates are the highest in the City. Heart disease death rates are 1.5 times higher than the rest of Seattle and King County. Life expectancy is 13 years shorter when compared to Laurelhurst in North Seattle; one of Seattle's wealthiest neighborhoods. Ardagh Glass has existed in the Duwamish Valley for over 100 years where old practices and technologies have led to a legacy of frequent air pollution violations.

By evaluating Ardagh Glass and other glass facilities as its own sector, we believe Washington state will identify emission-reducing options that if required will improve air quality and help achieve reasonable progress in this round of regional haze rulemaking. Historically, conservation and environmental work has concerned itself with protecting nature from people and has thus "siloed" its work (e.g., mainstream conservation vs. environmental justice.) While this siloed approach has led to the protection of many vulnerable habitats, it ignores the reality that people live in concert with and are a part of nature; to protect one and not the other is a job half done. By considering viewshed protection and environmental justice at the same time, we can collectively begin to dismantle the silos that exist in conservation and environmental work and chart a new path forward.

Ecology recognizes these environmental justice concerns, and that "pollution and environmental contamination can affect everyone living in Washington, but some people are significantly more burdened than others."[264] Furthermore, DOE explains that "[r]esearch shows that people of color, low-income people, and indigenous people are disproportionately harmed by environmental hazards … have real impacts on the lives of many in Washington, such as: …[h]igher rates of illness and disease … [m]ore frequent hospitalization [and] [l]ower life expectancy. We support the Department's commitment "to making decisions that do not place disproportionate burdens on disadvantaged communities," while "seeking to lift the weight of pollution and contamination borne by those communities." Additionally, we applaud DOE's "focus ... [of its] time and resources toward strategic actions to address these long-standing inequities" so that its actions "will lead to improvements in health and the environment, and more resilient communities in Washington."

In addition to Ecology's commitments, the Governor's Interagency Council on Health Disparities (Governor's Council) was established by the Legislature in 2006 when it passed, and the Governor signed a bill to create it.[265] Under the law, the Governor's Council:

- Creates an action plan for eliminating health disparities by race, ethnicity, and gender in Washington.
- Convenes advisory committees to assist in the planning and development of specific issues in collaboration with several state agencies and non-government stakeholders.[266]

[264] Department of Ecology, "Environmental Justice at Ecology," available at https://ecology.wa.gov/About-us/Accountability-transparency/Environmental-Justice. ("Exhibit 6," attached.)
[265] Governor's Interagency Council on Health Disparities, "The Council's Work," available at https://healthequity.wa.gov/TheCouncilsWork. ("Exhibit 7," attached.)
[266] *Id.*

Additionally, Section 221, subsection 48 of the 2019-2021 biennial operating budget (Engrossed Substitute Senate Bill 1109) directed the Governor's Council to convene and staff an Environmental Justice Task Force,[267, 268] which includes a representative from Ecology. "The Task Force is responsible for recommending strategies to incorporate environmental justice principles into future state agency actions."[269] The EJ Task Force was required to "submit a final report by October 31, 2020 to include:

> 1. Guidance for using the Washington Environmental Health Disparities Map, hosted on the Department of Health's website to identify communities that are highly impacted by environmental justice issues with current demographic data.
>
> 2. Best practices for increasing meaningful and inclusive community engagement that takes into account barriers to participation.
>
> 3. Measurable goals for reducing environmental health disparities for each community in Washington state and ways in which state agencies may focus their work towards meeting those goals.
>
> 4. Model policies that prioritize highly impacted communities and vulnerable populations for the purpose of reducing environmental health disparities and advancing a healthy environment for all residents. The Governor's Council includes several task force groups, including the Environmental Justice Task Force.[270]

The EJ Task Force's posted materials for 2019 and 2020[271] demonstrate considerable activity and include: Task Force meeting agendas, minutes and materials; Mapping Subcommittee meeting agendas and minutes; Community Engagement Subcommittee agendas and minutes; Task Force Feedback Listening Session agenda minutes, materials and minutes; and Task Force Work Group agenda and minutes.[272] However, there is no information available on the final report that was due October 31, 2020. The January 2020, Report of the Governor's Council's recognizes EPA's definition of environmental justice: "[t]he Environmental Protection Agency defines environmental justice as, '…the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.'"[273]

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267 "The Governor's Interagency Council on Health Disparities: State Policy Action Plan to Eliminate Health Disparities," (Jan. 2020) (2020 Council Report), available at https://healthequity.wa.gov/Portals/9/Doc/Publications/Reports/HDC-ActionPlan-Jan2020.pdf. ("Exhibit 8," attached.)

268 Governor's Interagency Council on Health Disparities, 2019 and 2020 Environmental Justice Task Force Materials, available at https://healthequity.wa.gov/TaskForceMeetings/EnvironmentalJusticeTaskForce. ("Exhibits 9 and 10," attached.)

269 2020 Council Report at 6.

270 *Id.*

271 Environmental Justice Task Force Meeting Materials, available at https://healthequity.wa.gov/TaskForceMeetings/EnvironmentalJusticeTaskForce. ("Exhibits 9 and 10," attached.)

272 *Id.*

273 2020 Council Report at 6, citing EPA's Environmental Justice website, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice. ("Exhibit 11," attached)

Under the Clean Air Act, states are permitted to include in a SIP measures that are authorized by state law but go beyond the minimum requirements of federal law.[274] Therefore, consistent with the Governor's Council and the Environmental Task Force's efforts, Ecology should analyze the environmental justice impacts of its second planning period haze SIP. For those RP sources located near a low-income or minority community that suffers disproportionate environmental harms, Ecology's four-factor analysis for that source should take into consideration how each considered measure would either increase or reduce the environmental justice impacts to the community. Such considerations will not only lead to sound policy decisions but are also pragmatic as pointed out above, most of the same sectors and sources implicated under the regional haze program are of concern to disproportionately impacted communities in Washington. Thus, considering the intersection of these issues and advancing regulations accordingly will help deliver necessary environmental improvements across issue areas, reduce uncertainty for the regulated community, increase the state's regulatory efficiency, result in more rational decision making and be consistent with the Washington State Legislature's and Governor's directives, priorities and funding to focus on policies that "prioritize highly impacted communities and vulnerable populations for the purpose of reducing environmental health disparities and advancing a healthy environment for all residents."[275]

There are additional legal grounds for considering environmental justice when determining reasonable progress controls. Under the Clean Air Act, states are permitted to include in a SIP measures that are authorized by state law but go beyond the minimum requirements of federal law.[276] Moreover, the State can also consider environmental justice when developing its haze plan, regardless of whether the Clean Air Act's haze provisions require such consideration. Ultimately, EPA will review the haze plan that Washington submits, and EPA will be required to ensure that its action on Washington's haze plan addresses any disproportionate environmental impacts of the pollution that contributes to haze. In addition to existing Executive Orders that requires federal executive agencies such as EPA to "make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs,

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[274] *See Union Elec. Co v. EPA*, 427 U.S. 246, 265 (1976) ("States may submit implementation plans more stringent than federal law requires and . . . the Administrator must approve such plans if they meet the minimum requirements of s 110(a)(2)."); *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1126 (10th Cir. 2009) (quoting *Union Elec. Co.*, 427 U.S. at 265) ("In sum, the key criterion in determining the adequacy of any plan is attainment and maintenance of the national air standards . . . 'States may submit implementation plans more stringent than federal law requires and [ ] the [EPA] must approve such plans if they meet the minimum [Clean Air Act] requirements of § 110(a)(2).'"); *BCCA Appeal Group v. EPA*, 355 F.3d 817, 826 n. 6 (5th Cir. 2003) ("Because the states can adopt more stringent air pollution control measures than federal law requires, the EPA is empowered to disapprove state plans only when they fall below the level of stringency required by federal law.").

[275] 2020 Council Report at 6.

[276] *See Union Elec. Co v. EPA*, 427 U.S. 246, 265 (1976) ("States may submit implementation plans more stringent than federal law requires and . . . the Administrator must approve such plans if they meet the minimum requirements of s 110(a)(2)."); *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1126 (10th Cir. 2009) (quoting *Union Elec. Co.*, 427 U.S. at 265) ("In sum, the key criterion in determining the adequacy of any plan is attainment and maintenance of the national air standards . . . 'States may submit implementation plans more stringent than federal law requires and [ ] the [EPA] must approve such plans if they meet the minimum [Clean Air Act] requirements of § 110(a)(2).'"); *BCCA Appeal Group v. EPA*, 355 F.3d 817, 826 n. 6 (5th Cir. 2003) ("Because the states can adopt more stringent air pollution control measures than federal law requires, the EPA is empowered to disapprove state plans only when they fall below the level of stringency required by federal law.").

policies, and activities on minority populations and low-income populations,"[277] on January 27, 2021, the current Administration signed "Executive Order on Tackling the Climate Crisis at Home and Abroad."[278] The new Executive Order on climate change and environmental justice provides that:

It is the policy of [this] Administration to organize and deploy the full capacity of its agencies to combat the climate crisis to implement a Government-wide approach that reduces climate pollution in every sector of the economy; … protects public health … delivers environmental justice …[and that] … [s]uccessfully meeting these challenges will require the Federal Government to pursue such a coordinated approach from planning to implementation, coupled with substantive engagement by stakeholders, including State, local, and Tribal governments."[279]

Washington can facilitate EPA's compliance with these Executive Orders by considering environmental justice in its SIP submission.

Consistent with legal requirements and government efficiency, we urge Washington to take impacts to EJ communities, like the ones we have expressed for the Ash Grove Cement and Ardagh Glass facilities, into consideration as it evaluates all sources that impact regional haze.

**Conclusion**

We appreciate Ecology's consideration of these comments. Additionally, we look forward to reviewing and providing comments on the draft plan in the spring of 2021 during the official public comment period. Please do not hesitate to contact me with any questions.

Sincerely,

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[277] Exec. Order No. 12898, § 1-101, 59 Fed. Reg. 7629 (Feb. 16, 1994), as amended by Exec. Order No. 12948, 60 Fed. Reg. 6381 (Feb. 1, 1995).
[278] "Executive Order on Tackling the Climate Crisis at Home and Abroad," (Jan. 27, 2021) (Climate Change and EJ EO), available at https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/; *see also,* White House Fact Sheet, "President Biden Takes Executive Actions to Tackle the Climate Crisis at Home and Abroad, Create Jobs, and Restore Scientific Integrity Across Federal Government," (Jan. 27, 2021), available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/27/fact-sheet-president-biden-takes-executive-actions-to-tackle-the-climate-crisis-at-home-and-abroad-create-jobs-and-restore-scientific-integrity-across-federal-government/.
[279] Climate Change and EJ EO, § 201.

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Kathy Taylor, Department of Ecology
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Enclosures

## List of Exhibits

1. Klafka, Steven, P.E. BCEE, Environmental Engineer, Wingra Engineering, S.C., "The Four-Factor Reasonable Progress Analysis for Ardagh Glass," (Jan. 27, 2021).
2. National Parks Conservation Association comments submitted on the Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County), which included proposed source-specific amendments for Ecology's Regional Haze SIP Revision, (Dec. 3, 2020).
3. "Petition for Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," submitted by National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Coalition to Protect America's National Parks, Appalachian Mountain Club, Western Environmental Law Center and Earthjustice, to former EPA Administrator Andrew Wheeler (May 8, 2020).
4. Stamper, V. & M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at 139-144.
5. 2013 Consent Decree, *United States et al. v. Ash Grove Cement Company*, (No. 2:13-cv-02299-JTM-DJW), available at https://www.epa.gov/sites/production/files/documents/ashgrove-cd.pdf.
6. Department of Ecology, "Environmental Justice at Ecology," available at https://ecology.wa.gov/About-us/Accountability-transparency/Environmental-Justice.
7. Governor's Interagency Council on Health Disparities, "The Council's Work," available at https://healthequity.wa.gov/TheCouncilsWork.
8. "The Governor's Interagency Council on Health Disparities: State Policy Action Plan to Eliminate Health Disparities," (Jan. 2020) (2020 Council Report), available at https://healthequity.wa.gov/Portals/9/Doc/Publications/Reports/HDC-ActionPlan-Jan2020.pdf.
9. Governor's Interagency Council on Health Disparities, Environmental Justice Task Force Materials, available at https://healthequity.wa.gov/TaskForceMeetings/EnvironmentalJusticeTaskForce.
10. Environmental Justice Task Force Meeting Materials, available at https://healthequity.wa.gov/TaskForceMeetings/EnvironmentalJusticeTaskForce.
11. EPA's Environmental Justice website, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.

**Wingra Engineering, S.C.**
*Environmental Engineering Consultants*

January 27, 2021

National Parks Conservation Association
Clean Air and Climate Program
Attn: Stephanie Kodish, Senior Director & Counsel
777 6th Street NW, Suite 700
Washington, DC 20001-3723

Subject: Four-Factor Reasonable Progress Analysis
Ardagh Glass, Inc.
Seattle, Washington

Dear Ms. Kodish:

The National Parks Conservation Association requested the preparation of a Four-Factor Reasonable Progress Analysis for Ardagh Glass, Inc. in Seattle, Washington. This analysis evaluates the feasibility of installing emission control equipment for air pollutants which are precursors to regional haze. The enclosed report describes the procedures and results of this analysis.

Should you have further questions, please contact me at (608) 255-5030.

Sincerely,

**Wingra Engineering, S.C.**

Steven Klafka
Steven Klafka, P.E., BCEE
Environmental Engineer

Enclosure

*303 South Paterson Street, Madison, WI 53703, (608) 255-5030, (fax) 255-5042, www.wingraengineering.com*

# Ardagh Glass, Inc.

## Seattle, Washington

# Four-Factor Reasonable Progress Analysis

## January 27, 2021

*Prepared by:*

*Steven Klafka, P.E., BCEE*

*Wingra Engineering, S.C.*

*Madison, Wisconsin*

## 1.0 INTRODUCTION

In 2010, Washington Department of Ecology (DOE/WDOE) updated its regional haze state implement plan to improve visibility in certain national parks and wilderness areas in the state.[1] These are referred to as Class I areas for implementation of air pollution protection regulations and include the following:

- Alpine Lakes Wilderness
- Glacier Peak Wilderness
- Goat Rocks Wilderness
- Mt. Adams Wilderness
- Mt. Rainier National Park
- North Cascades National Park
- Olympic National Park
- Pasayten Wilderness

Figure 1 is a WDOE map showing the location of these areas.[2]

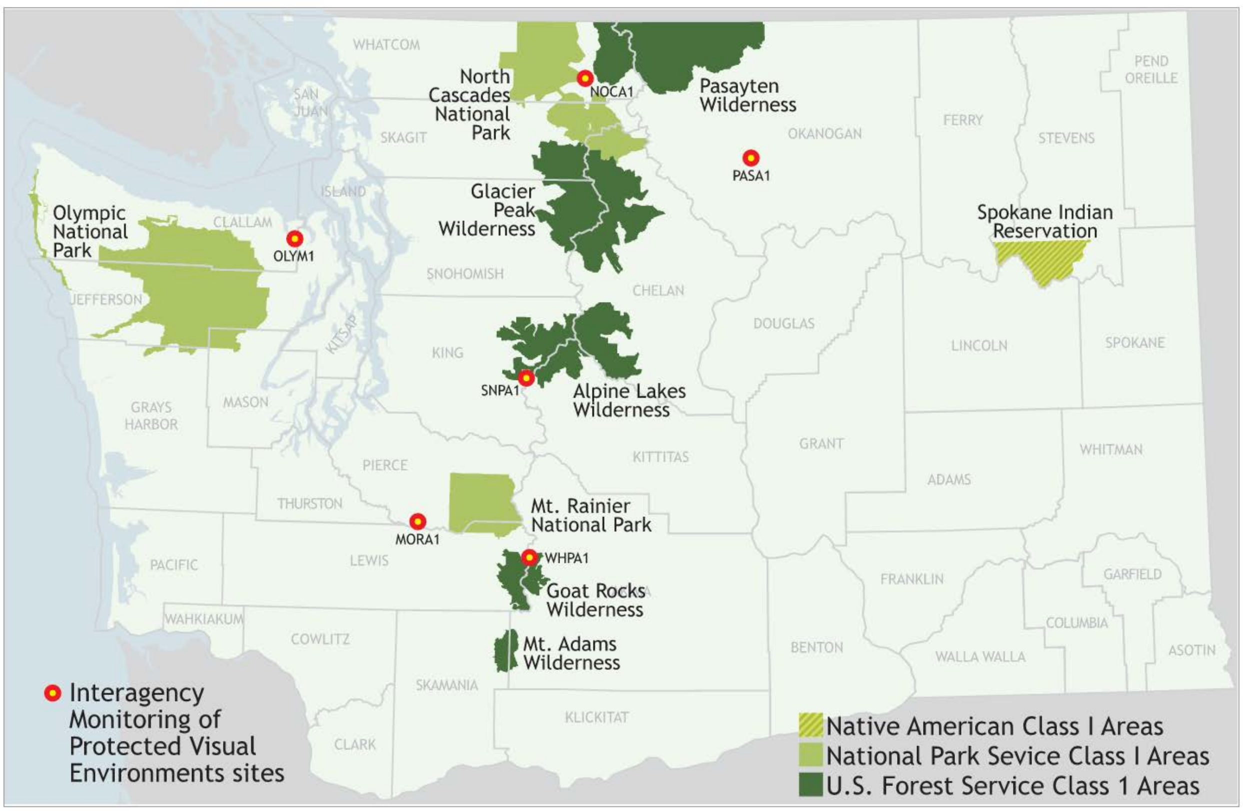


**Figure 1 - Washington State Class I Areas**

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[1] Department of Ecology, State of Washington, Regional Haze, State Implementation Plan, Final December 2010

[2] https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze

The DOE regional haze state implementation plan is evaluating the retrofit of emission control technology at large industrial sources to make reasonable progress toward natural conditions in Class 1 areas. To determine the effectiveness of retrofitting emissions control technology, USEPA requires states to use a Four-Factor Reasonable Progress Analysis (FFA). In its background document for this analysis, WDOE states:

*Consider 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 sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal (40 CFR 51.308(d)(1)(i)(A)). This four factor analysis is used to identify controls necessary to meet the reasonable progress goals for each mandatory Class 1 area (CIA).*

Therefore, the four statutory factors are:

- Costs of compliance
- Time necessary for compliance
- Energy and non-air quality impacts of compliance
- Remaining useful life of any potentially affected sources

This report presents an FFA for Ardagh Glass, Inc. located in Seattle, Washington. DOE has identified this industrial facility has potentially having impacts on regional haze at surrounding Class I areas.

## 2.0 FACILITY DESCRIPTION

Ardagh Glass, Inc. is located at 5801 East Marginal Way S. in Seattle, King County, Washington. It manufactures glass containers. It was issued Air Operating Permit No. 11656 on June 6, 2007. Specifications for the air pollution sources at the plant are taken from this operating permit and the Statement of Basis for Administrative Amendment 5-31-17 (SOB) which provides a description of activities and a compliance history for the plant. Both documents were obtained from the Puget Sound Clean Air Agency.[3]

The closest Class I areas to Ardagh include the following:

- Olympic National Park
- Alpine Lakes Wilderness
- Mount Rainier National Park
- Glacier Peak Wilderness
- Goat Rocks Wilderness

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[3] https://www.pscleanair.gov/182/List-of-Approved-Permits

In its regional haze plan, DOE modeled facilities that were within 300 km of Class I areas to determine if they had a significant impact these areas. The closest Class I area to Ardagh is the Alpine Lakes Wilderness at 53.5 km. All of the Class I areas are within the 300 km distance from Ardagh.

While there are numerous air pollution sources at glass manufacturing plants, the largest sources are the fossil fuel-fired furnaces which melt glass. At the Ardagh plant, there are five furnaces. No. 1 is an all-electric furnace; No. 2, No. 3 and No. 5 furnaces are oxy-fuel fired; and, No. 4 is an end-port regenerative furnace.

For the No. 1 glass furnace, DOE states that the company does not have any reported emissions from this electric furnace and it vents through the roof and normally has no visible emissions, but is capable of emitting visible emissions from the furnace during upset conditions. It will be assumed for this analysis that there are no significant emissions from this furnace and its emissions will not be considered.

Specifications for the remaining furnaces are provided in Table 1. The actual daily production melt rates are taken from the Puget Sound Clean Air Agency SOB and come from 1994 source tests. Current emission inventory reports only provide annual production rates. If 1994 are the last source tests, it is recommended that DOE require new stack tests to verify current actual emission rates.

The full production capacity of each furnace provided by the SOB is also summarized in Table 1.

***Table 1 - Ardagh Glass Furnace Specifications***

| Glass Melting Furnace | Tested Melt Rate (tons per day) | Capacity Melt Rate (tons per day) |
|---|---|---|
| No. 2 | 144.6 | 195 |
| No. 3 | 166.8 | 160 |
| No. 4 | 131.3 | 430 |
| No. 5 | 130.7 | 205 |
| Total | 573.4 | 990 |

Table 2 provides the annual actual emissions from the Ardagh plant as reported in its emissions inventory submitted to DOE.[4] The air pollutants evaluated include nitrogen oxides ($NO_x$), sulfur dioxide ($SO_2$) and particulate matter (PM). The actual emissions can be used to estimate the cost effectiveness of emission control equipment in an FFA.

[4] Department of Ecology, State of Washington, Air emissions inventory summaries, https://ecology.wa.gov/Air-limate/Air-quality/Air-quality-targets/Air-emissions-inventory

Furnaces Nos. 2, 3 and 5 are oxy-fuel fired. This combustion technique would reduce the formation of $NO_x$. It is assumed that any $NO_x$ emission reductions due to this technique are already incorporated into the reported actual emissions summarized in Table 2. The DOE SOB indicates Furnace No. 5 was equipped with a Tri-Mer Cloud Mist Scrubber in approximately 2009. This scrubber would capture the $SO_2$ and PM emissions. It is assumed that the reported actual emissions incorporate any emission reductions due to the use of the mist scrubber.

***Table 2 - Ardagh Actual Emissions***

| Reporting | $NO_x$ | $SO_2$ | $PM_{10}$ | Total |
|---|---|---|---|---|
| 2012 | 227.1 | 61.4 | 75.2 | 363.7 |
| 2013 | 166.5 | 73.3 | 92.8 | 332.6 |
| 2014 | 172.1 | 105.9 | 73.2 | 351.2 |
| 2016 | 153.7 | 98.7 | 95.3 | 347.6 |
| 2017 | 153.3 | 98.7 | 88.2 | 340.2 |
| 2018 | 167.6 | 89.9 | 82.2 | 339.7 |
| Maximum | - | - | - | 351.2 |

Table 3 provides the annual potential, legally enforceable emissions from the Ardagh plant. It is a common practice in air pollution control, especially for a Best Available Control Technology analysis following the federal Prevention of Significant Deterioration regulations, to estimate the cost effectiveness of air pollution control equipment based on 100% capacity and the potential emissions. As shown in Table 2, actual annual emissions vary with annual production. Looking at historical emission inventory reports, total emissions have been as high as 700.7 tpy in 2008. Based on the Ardagh air quality operating permit, there is no limitation on annual production. Actual emissions are approved as long as they remain below the potential emissions approved by the operating permit. Potential emissions, in addition to actual emissions, can be used to estimate the cost effectiveness of emission control equipment in an FFA.

*Table 3 - Ardagh Potential Emissions*

| Glass Melting Furnace | Capacity (tons per day) | Air Pollutant | Limitation (lbs/ton) | Limitation (tpy) |
|---|---|---|---|---|
| No. 2 | 195 | $NO_x$ | 3.8 | 135 |
| | | $SO_2$ | 1.6 | 57 |
| | | PM | 1.0 | 36 |
| No. 3 | 160 | $NO_x$ | 3.8 | 111 |
| | | $SO_2$ | 1.6 | 47 |
| | | PM | 1.0 | 29 |
| No. 4 | 430 | $NO_x$ | 3.8 | 298 |
| | | $SO_2$ | 1.6 | 126 |
| | | PM | 1.0 | 78 |
| No. 5 | 205 | $NO_x$ | 3.8 | 142 |
| | | $SO_2$ | 1.6 | 60 |
| | | PM | 1.0 | 37 |
| Total | 990 | $NO_x$ | - | 687 |
| | | $SO_2$ | - | 289 |
| | | PM | - | 181 |
| | | All | - | 1,156 |

## 3.0 FOUR-FACTOR ANALYSIS

The four factors included in this analysis are:

- Costs of compliance
- Time necessary for compliance
- Energy and non-air quality impacts of compliance
- Remaining useful life of any potentially affected sources

Each of these factors are evaluated for the Ardagh plant.

### 3.1 Costs of Compliance

The emissions from the Ardagh furnaces which need to be controlled are $NO_x$, $SO_2$ and PM. Historically, these pollutants were controlled using separate air pollution control systems due to their physical and chemical properties. $NO_x$ emission control requires changes in the combustion conditions that form $NO_x$ from $N_2$ at high temperatures, or use ammonia or urea injection to react with the $NO_x$ to form $N_2$ as the reaction product. $SO_2$ emissions require wet or dry injection of a chemical to react with and neutralize this pollutant. PM emissions are solids which requires capture by filtering or agglomeration into larger particles using water sprays.

Furnace No. 1 at the Ardagh plant is electrically heated. Puget Sound concluded there were no emissions from this furnace except during upsets. If this is true, then changing the other four furnaces from fossil fuel-fired to electrically heated is an emission control option that DOE should evaluate. Glass furnaces are rebuilt every 10 to 20 years. The next rebuilt would be an appropriate time to change the heating method.

A common resource to determine the latest control methods for an industry is the *BACT Clearinghouse* operating by the United States Environmental Protection Agency (USEPA).[5] This website lists the most recent results of Best Available Control Technology analyses for air pollution permits issued to major source under the Prevention of Significant Determination. For glass manufacturing, the website provides only two entries during the past 10 years. These include the 700 ton per day flat glass plant approved for Cardinal FG Company in Winlock, Washington. As BACT, the glass furnace was equipped with a spray drier scrubber for $SO_2$ control, ESP to capture PM, and use of the *3R Process* combustion modifications to reduce $NO_x$ emissions. The second project was 18 furnaces for the production of high purity glass at the Corning Incorporated plant in Canton, New York. BACT for $NO_x$ emissions was determined to be the use of oxygen-fired combustion to minimize the formation of $NO_x$.

There have been additional emission control projects in the U.S. which have not been subject to the PSD regulations so are not documented in the BACT Clearinghouse. These also provide insight into demonstrated emission control methods.

In 2010, USEPA reached a settlement with Saint Gobain Containers Inc. over violations of the Clean Air Act at their container glass plants.[6] The settlement required the installation of new emission control systems for $NO_x$ including the use of an Oxyfuel Furnace, Oxygen Enriched Air Staging (OEAS) and Selective Catalytic Reduction (SCR); new emission control systems for $SO_2$ including semi-dry scrubbers, dry scrubbers, cloud chamber scrubber systems and process controls; and, new emission control systems for PM including cloud chamber scrubber systems, electrostatic precipitators, or process controls. Ardagh Glass Inc. later purchased some of the Saint Gobain plants included in the USEPA settlement. These plants included the Seattle facility. In the settlement, this plant was required to use oxyfuel to reduce $NO_x$ emissions from Furnaces No. 3 and 5 and install a cloud chamber scrubber system to reduce $SO_2$ and PM emissions from Furnace No. 5.

In 2015, USEPA reached a settlement with Guardian Industries Corporation over violations of the Clean Air Act at their flat glass plants.[7] Guardian was required to install new emission controls for $NO_x$, $SO_2$ and PM including selective catalytic reduction, dry scrubbing and dust capture

[5] https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information
[6] https://www.epa.gov/enforcement/saint-gobain-containers-inc-clean-air-act-settlement
[7] https://www.epa.gov/enforcement/guardian-industries-corp-clean-air-act-settlement

equipment. For some plants, Guardian chose to use a new emission control technology which has been demonstrated to simultaneously control $NO_x$, $SO_2$ and PM emissions from glass plants. This technology uses catalytic ceramic filters in combination with ammonia injection for $NO_x$ control and reagent injection for $SO_2$ control. PM is captured on the surface of the ceramic filters.

In 2015, Cardinal FG Company began a voluntarily program to install additional control equipment to reduce it flat glass plant emissions. At three existing flat glass plants already equipped with spray drier – ESP control systems for $SO_2$ and PM control, an additional Selective Catalytic Reduction or SCR system for $NO_x$ control would be installed. At two existing flat glass plants using the *3R Process* for $NO_x$ control, the new catalytic ceramic filter control system has been installed. Compliance testing of catalytic ceramic filter systems show they are achieving the lowest emission levels for $NO_x$, $SO_2$ and PM combined at existing glass plants. Based on the system quotation used for this analysis, the guaranteed control efficiencies for these air pollutants are 90%, 75% and 95.8%, respectively.

The two catalytic ceramic filter installations at Cardinal FG were manufactured by the Tri-Mer Corporation. Table 4 summarizes glass plant installations of the catalytic ceramic control system by Tri-Mer. It is noteworthy that one of the installations is the Ardagh Glass container plant in Dolton, Illinois. This makes this type of system an excellent option to consider for controlling the emission of these pollutants from the Ardagh plant in Seattle. Based on the success of the catalytic ceramic filter systems at existing glass plants, it will be used for the FFA for the Ardagh plant in Seattle.

***Table 4 - Tri-Mer Filter Projects in U.S.***

| Company | Location | Glass Type |
|---|---|---|
| Durand | Millville, NJ | Tableware |
| Anchor | Monaca, PA | Mixed |
| AGC | Church Hill, TN | Flat |
| Gallo | Modesto, CA | Container |
| AGC | Hill, KS | Flat |
| Adagh | Dolton, IL | Container |
| Kohler | Kohler, WI | Specialty |
| Guardian | Carleton, MI | Flat |
| PG Corporation | L.A. Basin | Specialty |
| Cardinal FG | Mooresville, NC | Flat |
| Cardinal FG | Durant, OK | Flat |

For typical BACT analyses, order-of-magnitude cost estimates are typically generated.[8] The cost estimate is improved if it incorporates actual vendor quotations for the required equipment. A prior quotation for a catalytic ceramic filter system was available for one of the Cardinal FG plants. Like the Ardagh plant, the cost estimate reflects the retrofit of a new control system at an existing

[8] USEPA, Air Pollution Control Manual, Sixth Edition, EPA/452/B-02-001 January 2002.

industrial facility. These capital, installation and operating costs were adjusted to reflect the differences between the Cardinal and Ardagh plants. The development of this cost estimate is provided in the supporting calculations of Appendix A.

As previously noted, BACT analyses are typically based on full capacity and potential emissions. For Ardagh, cost estimates were developed for both actual and potential production and emissions. The actual cost estimate is based on reported emissions and incorporates any existing air pollution control measures on the four glass furnaces at Ardagh. The potential cost estimate reflects the production capacity and emissions approved for the four glass furnaces.

Table 5 presents a summary of the cost estimate for the Ardagh plant. Because the catalytic ceramic filter system is a multi-pollutant control technology, cost effectiveness was calculated based on the total expected emission reductions in $NO_x$, $SO_2$, and PM emissions. The cost effectiveness for actual conditions is $4,766 per ton of total air pollutants removed and for potential conditions is $2,238 per ton of total air pollutants removed. Both of these values are well within the cost effectiveness level considered reasonable in prior BACT and control equipment analyses by regulatory agencies. It is not unusual for $10,000 per ton of pollutant removed to be considered acceptable. In correspondence with DOE staff on this topic, they provided reasonable cost example values for actual and potential emissions of $5,250 and 4,000 per ton, respectively.[9] The estimates for Ardagh are within these values. It is concluded that the installation of a catalytic ceramic filter system at the Ardagh plant in Seattle would be considered a reasonable expense.

This analysis is more accurate than one based on order-of-magnitude cost estimates. However, it would be improved if a budget quotation were obtained for the plant.

### 3.2 Time necessary for compliance

Based on prior projects, the time frame to obtain a quotation for a catalytic ceramic filter, issue a purchase order, complete engineering, construct and install the equipment is 12 months. Furnace No. 5 at the Seattle plant is equipped with a Cloud Mist Scrubber manufactured by Tri-Mer. Additionally, the plant in Dolton, Illinois is equipped with a catalytic ceramic filter system manufactured by Tri-Mer. The familiarity of Ardagh staff with Tri-Mer products would improve the ability to obtain a quotation and installation of a new control system at the Seattle plant.

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[9] Email, P. Gent – WDOE to S. Klafka – Wingra Engineering, Regional haze four-factor analysis for Ardagh Glass, Inc., January 19, 2021.

***Table 5 - Cost Estimate for Catalytic Ceramic Filter System to Control Actual and Potential Emissions from Ardagh Glass, Inc.***

| Basis | Actual | Potential |
|---|---|---|
| Capacity (tpd) | 573.4 | 990 |
| Capital Costs | $11,866,967 | $16,468,204 |
| Annual Capital Costs | $816,210 | $1,132,683 |
| Annual Operating Costs | $330,980 | $700,622 |
| Annual Capital and Operating Costs | $1,147,190 | $1,833,305 |
| Inlet $NO_x$ (tpy) | 172 | 687 |
| Inlet $SO_2$ (tpy) | 106 | 289 |
| Inlet PM (tpy) | 73 | 181 |
| Inlet Total $NO_x$, $SO_2$ and PM (tpy) | 351 | 1,156 |
| Outlet $NO_x$ (tpy) | 17 | 69 |
| Outlet $SO_2$ (tpy) | 26 | 72 |
| Outlet PM (tpy) | 3 | 8 |
| Outlet Total $NO_x$, $SO_2$ and PM (tpy) | 47 | 148 |
| Removed $NO_x$ (tpy) | 155 | 618 |
| Removed $SO_2$ (tpy) | 79 | 217 |
| Removed PM (tpy) | 70 | 173 |
| Removed Total $NO_x$, $SO_2$ and PM (tpy) | 304 | 1,008 |
| Cost Effectiveness ($ per Total Ton removed) | $3,768 | $1,819 |

### 3.3 Energy and non-air quality impacts of compliance

Significant operating costs in order of magnitude include electricity, ammonia reagent, hydrated lime reagent and labor. These costs are taken into account in the enclosed cost estimates. The cost estimates provided in this report incorporate electricity usage for control system fans.

The cost estimates adjust ammonia reagent consumption rates based on the anticipated actual and potential emissions. The ammonia selected for the control of $NO_x$ emissions is 19% aqueous ammonia. This is a less concentrated and safer alternative to anhydrous ammonia. This type of ammonia has no federal requirement to evaluate the potential impacts of an accidental release.

The cost estimates adjust hydrated lime consumption rates based on the anticipated actual and potential emissions. The calcium sulfate formed by the reaction of hydrated lime with $SO_2$ will be captured as dust by the ceramic filters. Calcium sulfate is a raw material in glass making and it is common practice to recycle the captured dust to the glass furnace. The cost estimates provided with this report includes the cost of a recycling system for 100% of the dust. This system avoids waste disposal impacts and costs.

### 3.4 Remaining useful life of any potentially affected sources

It is common practice in the glass industry to rebuild glass furnaces after their refractory has completed its useful life. This may last 10 to 20 years. It is not clear from the available DOE background documents how long a glass factory has been in the location of Ardagh. A history of glass container manufacturing suggests there has been a Ardagh connected plant in Seattle since 1931.[10] This would suggest there have been numerous new and rebuilt furnaces, and a new control system at the Ardagh plant would continue to operate for its entire useful life. As previously discussed with available emission control options, the time when a glass furnace is rebuilt would be an appropriate time to consider changing from a fossil fuel-fired furnace to one that is electrically heated and eliminating the emissions associated with regional haze.

## 4.0 CONCLUSIONS

It is technically feasible to add additional emission controls to the Ardagh Glass Inc. plant in Seattle and further reduce its air pollution emissions of $NO_x$, $SO_2$ and PM which contribute to regional haze. The catalytic ceramic control system evaluated in the enclosed FFA has been installed on other glass plants, including Ardagh's own plant in Illinois.

The existing Seattle plant does have some control measures in place. Furnace Nos. 2, 3 and 5 are oxy-fuel fired to reduce their $NO_x$ emissions and Furnace Nos. 3 and 5 are equipped with a cloud mist control system to reduce $SO_2$ and PM emissions. Nevertheless, the residual emissions can be controlled further by the use of the catalytic ceramic control system.

Based on actual and potential emissions, the enclosed cost estimates show that the new control system would have a cost effectiveness of $3,768 and $1,819 per ton of total air pollutants removed, respectively. Both of these values represent a reasonable expenditure for the reduction of $NO_x$, $SO_2$ and PM emissions.

[10] https://glassbottlemarks.com/ball-bros-glass-company/

# Appendix A

# Supporting Cost Calculations

| | Reference | Original | Reference | Original | Reference | Ardagh | Reference | Ardagh |
|---|---|---|---|---|---|---|---|---|
| Basis | | Potential | | Potential | | Actual | | Potential |
| Capacity (tpd) | Quotation | 700 | | 700 | 2017 DOE SOB | 573.4 | 2017 DOE SOB | 990 |
| Inlet NOx (lbs/ton) | Quotation | 18.0 | | 18.0 | | | 2017 DOE SOB | 3.8 |
| Inlet SO2 (lbs/ton) | Quotation | 4.0 | | 4.0 | | | 2017 DOE SOB | 1.6 |
| Inlet PM (lbs/ton) | Quotation | 1.2 | | 1.2 | | | 2017 DOE SOB | 1 |
| Inlet NOx (tpy) | Calculated | 2,299.5 | | 2,299.5 | 2014 Inventory | 172.1 | Calculated | 686.6 |
| Inlet SO2 (tpy) | Calculated | 511.0 | | 511.0 | 2014 Inventory | 105.9 | Calculated | 289.1 |
| Inlet PM (tpy) | Calculated | 153.3 | | 153.3 | 2014 Inventory | 73.2 | Calculated | 180.7 |
| NOx Removal (%) | IN vs OUT | 90.0% | | 90.0% | Same as Original | 90.0% | Same as Original | 90.0% |
| SO2 Removal (%) | IN vs OUT | 75.0% | | 75.0% | Same as Original | 75.0% | Same as Original | 75.0% |
| PM Removal (%) | IN vs OUT | 95.8% | | 95.8% | Same as Original | 95.8% | Same as Original | 95.8% |
| Outlet NOx (lbs/ton) | Quotation | 1.8 | | 1.8 | | | Calculated | 0.38 |
| Outlet SO2 (lbs/ton) | Quotation | 1.0 | | 1.0 | | | Calculated | 0.40 |
| Outlet PM (lbs/ton) | Quotation | 0.1 | | 0.1 | | | Calculated | 0.04 |
| Outlet NOx (tpy) | Calculated | 230.0 | | 230.0 | Calculated | 17.2 | Calculated | 68.7 |
| Outlet SO2 (tpy) | Calculated | 127.8 | | 127.8 | Calculated | 26.5 | Calculated | 72.3 |
| Outlet PM (tpy) | Calculated | 6.4 | | 6.4 | Calculated | 3.1 | Calculated | 7.5 |
| Removed NOx (tpy) | Calculated | 2,069.6 | | 2,069.6 | Calculated | 154.9 | Calculated | 617.9 |
| Removed SO2 (tpy) | Calculated | 383.3 | | 383.3 | Calculated | 79.4 | Calculated | 216.8 |
| Removed PM (tpy) | Calculated | 146.9 | | 146.9 | Calculated | 70.2 | Calculated | 173.1 |
| Removed NOx, SO2 and PM (tpy) | Calculated | 2,599.7 | | 2,599.7 | Calculated | 304.5 | Calculated | 1,007.9 |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| **Capital Costs** | | Original (2015) | Inflation | Original (2020) | Adjustment Method | Actual Basis | Adjustment Method | Potential Basis |
| Complete System Equipment and Installation | | $12,159,935 | 1.10 | $13,375,929 | Six-Tenths by Capacity | $11,866,967 | Six-Tenths by Capacity | $16,468,204 |
| Capital Recovery Factor (CRF) | CRF (20 yrs, 3.25%) | 0.06878 | CRF (20 yrs, 3.25%) | | CRF (20 yrs, 3.25%) | 0.06878 | CRF (20 yrs, 3.25%) | 0.06878 |
| | | $836,360 | | | | $816,210 | | $1,132,683 |
| **Operating Costs** | | | | | | | | |
| Electricity | | 188953 | 1.10 | $207,848 | Ratio by Capacity | $170,257 | Ratio by Capacity | $293,957 |
| 19% Aqueous Ammonia | | 665665 | 1.10 | $732,232 | Ratio by Inlet NOx | $54,802 | Ratio by Inlet NOx | $218,623 |
| Hydrated Lime | | 361,810 | 1.10 | $397,991 | Ratio by Inlet SO2 | $29,787 | Ratio by Inlet SO2 | $118,829 |
| Labor for Operation and Maintenance | | 69,213 | 1.10 | $76,134 | No Change | 76,134 | No Change | 69,213 |
| Annual Operating Costs | | 1,285,641 | | | | 330,980 | | 700,622 |
| | | | | | | | | |
| Capital Costs | | $12,159,935 | | | | $11,866,967 | | $16,468,204 |
| Annual Capital Costs | | $836,360 | | | | $816,210 | | $1,132,683 |
| Annual Operating Costs | | $1,285,641 | | | | $330,980 | | $700,622 |
| Annual Capital and Operating Costs | | $2,122,001 | | | | $1,147,190 | | $1,833,305 |
| Inlet NOx (tpy) | | 2,300 | | | | 172 | | 687 |
| Inlet SO2 (tpy) | | 511 | | | | 106 | | 289 |
| Inlet PM (tpy) | | 153 | | | | 73 | | 181 |
| Inlet NOx, SO2 and PM (tpy) | | 2,964 | | | | 351 | | 1,156 |
| Outlet NOx (tpy) | | 230 | | | | 17 | | 69 |
| Outlet SO2 (tpy) | | 128 | | | | 26 | | 72 |
| Outlet PM (tpy) | | 6 | | | | 3 | | 8 |
| Outlet NOx, SO2 and PM (tpy) | | 364 | | | | 47 | | 148 |
| Removed NOx (tpy) | | 2,070 | | | | 155 | | 618 |
| Removed SO2 (tpy) | | 383 | | | | 79 | | 217 |
| Removed PM (tpy) | | 147 | | | | 70 | | 173 |
| Removed NOx, SO2 and PM (tpy) | | 2,600 | | | | 304 | | 1,008 |
| Cost Effectiveness ($ per ton removed) | | $816 | | | | $3,768 | | $1,819 |

Notes:

Complete System Equipment and Installation includes: emission control system, controls, infrastructure, engineering design and project management, installation, services, batch recycle system, ammonia tank shelter.

Inflation multiplier from November 2015 to December 2020 = 1.10 - https://www.bls.gov/data/inflation_calculator.htm

Capital Recover Factor based on lifetime of operation and % interest from DOE, Four-Factor Analysis, https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze

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**Attachment 2**

May 8, 2020

***Via Federal Express and Email***

Administrator Andrew Wheeler
Office of the Administrator
United States Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460
Wheeler.andrew@epa.gov

**Re: Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period**

Dear Administrator Wheeler:

I. Introduction

National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Western Environmental Law Center, Appalachian Mountain Club, Coalition to Protect America's National Parks, and Earthjustice (hereinafter "Conservation Organizations") hereby petition[1] the Administrator of the United States Environmental Protection Agency ("EPA") to reconsider the entitled "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (hereinafter "Final Guidance" or "Guidance")[2] and replace it with

[1] This Petition is filed pursuant to section 4(d) of the Administrative Procedure Act ("APA"), 5 U.S.C. § 553(e), and, to the extent it may be applicable and relevant, section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B).

[2] EPA issued the Final Guidance on August 20, 2019 via Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards to EPA Air Division Directors.

guidance that comports with the Clean Air Act ("CAA") and the Regional Haze Rule, and aids states in making progress towards achieving the national goal of natural visibility conditions at all Class I areas.[3] The Final Guidance is a significant departure from the Draft Guidance[4] issued in 2016 for the second planning period and contains provisions that are expressly at odds with the Clean Air Act and Regional Haze Rule. The table below summarizes how key provisions of the Final Guidance should be revised to comply with the requirements of the applicable statutes and regulations.

The Guidance unlawfully directs states on how they may exclude certain emission sources from four-factor consideration and delay or altogether avoid reducing emissions necessary to meet Congress's mandate that the states make reasonable progress towards the national goal of restoring natural visibility to Class I area national parks and wilderness areas. 42 U.S.C. § 7491(b)(2). The Guidance not only conflicts with the text and purpose of the Clean Air Act and the Regional Haze Rule itself, but it conflicts with EPA's 2016 Draft Guidance by arbitrarily constraining EPA review authority, diminishing the science of regional haze, and recasting technical and analytical requirements for State Implementation Plans ("SIPs"). Implementation of the Final Guidance will result in inconsistencies between SIPs, create arbitrary exceptions allowing states to avoid controlling emission sources, impede progress toward the national goal of a restoring natural visibility, and may actually degrade visibility at some Class I areas.

| Section of the Petition | Summary of Issue | Applicable Regional Haze Rule or other Regulations[5] |
|---|---|---|
| III.A. | States must comprehensively identify sources of human-caused visibility-impairing emissions across source categories and cannot arbitrarily defer some sources to another implementation period. | Section 51.308(f)(3)(ii) of the Regional Haze Rule and Clean Air Act section 169A(b) |
| III.B. | States have only limited discretion to decide which sources they consider for reasonable progress. SIPs will be found deficient where they fail to require emission reductions that collectively make reasonable progress towards natural visibility at all Class I areas in each planning period; no backsliding is permitted. | 82 Fed. Reg. at 3,088 and sections 51.308(f)(2)(i), 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B) |
| III.C. | States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire. | Sections 51.308(f)(2)(i), 51.308(f)(2)(iv)(C) |

[3] 42 U.S.C. §§ 7491, 7492; 82 Fed. Reg. 3078 (Jan. 10, 2017); 71 Fed. Reg. 60,612 (Oct.13, 2006); 70 Fed. Reg. 39,104 (July 6, 2005); 64 Fed. Reg. 35,714 (July 1, 1999).
[4] Draft Guidance on Progress Tracking Metrics, Long-term strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, (hereinafter "Draft Guidance") 81 Fed. Reg. 44,608 (July 8, 2016).
[5] Clean Air Act section 110(k)(5) provides EPA the authority to review a SIP and assess the adequacy of that SIP. Therefore any aspect of this guidance that interferes with that authority is in conflict.

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| III.D. | States cannot consider being under the uniform rate of progress (“URP”) when selecting sources for a four-factor analysis. The glidepath is not a safe harbor; rather a state must take measures necessary to make progress towards natural visibility at any Class I areas its emissions affect. | 82 Fed. Reg. at 3,093 |
| III.E. | Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control. | Section 51.308(f)(2)(iv)(D) |
| III.G. | States must include both “dominant” and “non-dominant” pollutants in their analyses of controls. | 82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)( (B), 51.308(f)(2)(i) |
| III.H. | States cannot eliminate volatile organic compounds (“VOCs”) and ammonia emissions from consideration. | 82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B), 51.308(f)(2)(i) |
| IV.A. | States must use methods permitted by statute and regulation to identify its sources that potentially affect visibility at Class I areas in other states, not merely any “reasonable method.” | 82 Fed. Reg. at 3,094 and sections 51.308(f)(2)(i), 51.308(d)(3)(iv) |
| IV.B. | States must consider cumulative impacts of sources or groups of sources to all affected Class I areas. | Section 51.308(f)(2)(i) |
| V.A. | States must prioritize emissions within their borders to achieve reasonable progress. | Sections 51.308(f)(1)(vi)(B), 51.308(f)(2)(iv)(D), and Clean Air Act section 169A(b) |
| VI.B. | States must adhere to the accounting principles of the Control Cost Manual and should compile and make publicly available the documentation for generic cost estimates. | Section 51.308(f)(2)(i) |
| VII.A. | States cannot allow sources to discontinue the use of currently operating controls. | Section 51.308(f)(2) and Clean Air Act section 169A(b)(2) |
| VIII | States should use regional scale modeling to support their regional haze SIPs. | Section 51.308(f)(3)(ii)(A), Appendix W to Part 51 |
| IX.A. | If a state’s reasonable progress goal (“RPG”) is above the URP, the state’s “robust demonstration” must include a consideration of specific items identified by EPA. | Section 51.308(f)(3)(ii) |
| X.A. | States must submit to EPA the emission inventory used in a regional haze SIP. | Section 51.308(f)(2)(iii), Clean Air Act section |

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|---|---|---|
| | | 110(k)(5), and EPA's Emission Inventory Guidance[6] |
| X.B. | States must ensure that Federal Land Managers' ("FLMs") opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP. | Sections 51.308(i), 51.308(f)(4) and Clean Air Act sections 169A(a) and (d) |
| XI.B. | Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations. | Section 51.308(f)(2)(i) |
| XI.C. | EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility. | Clean Air Act section 169A(a) |

This Petition seeks reconsideration and substantial revision of the Final Guidance so that the Guidance will direct states to deliver on the statutory objective of preventing future and remedying existing Class I area visibility impairment that results from human-caused pollution. As issued, the Final Guidance conflicts with this statutory objective, previous rulemaking and guidance; misdirects states as to how they can go about complying with their legal obligations to make reasonable progress towards restoring natural visibility to protected public lands; and otherwise fails to set expectations that comport with legal requirements for the second planning period.

In addition to the provisions noted in the table above, the Conservation Organizations incorporate several recommendations from their Comments on EPA's Draft Guidance[7] and request that EPA reconsider and revise the Final Guidance to direct states with regard to the following issues:

- States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.
- Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.
- States should include all visibility-impairing pollutants when calculating a source's annual emissions.
- States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

[6] EPA, Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations (May 2017), https://www.epa.gov/sites/production/files/2017-07/documents/ei_guidance_may_2017_final_rev.pdf.
[7] Conservation Organizations incorporate by reference their full Comments on the 2016 proposed Draft Guidance.

- States should analyze the climate and environmental justice impacts of measures to achieve reasonable progress.

The gains made in the first regional haze planning period established a critical, if delayed, foundation for our national parks and wilderness areas to make progress towards the natural visibility which they and their visitors and neighboring communities are due. The Final Guidance not only hinders future gains but in some cases actually jeopardizes the gains made in the first planning period. Conservation Organizations urge EPA to reconsider its Final Guidance and instead issue a revised guidance that directs states to fulfill regulatory requirements for reasonable progress in the second planning period to help attain clearer skies at America's prized national parks and wildernesses.

II. SIP development steps

As EPA states in the Final Guidance, the key steps to developing a regional haze SIP start with identifying the twenty percent most anthropogenically impaired days and the twenty percent clearest days and determining baseline, current, and natural visibility conditions for each Class I area within the state, and then determining which Class I area(s) in other states may be affected by the state's own emissions.[8] States must then screen sources and conduct a four-factor analysis of which controls are required before establishing reasonable progress goals.[9] Once a state has determined the reasonable progress measures to require at specific sources, the state must quantify the "reasonable progress goal"—i.e., the visibility improvement that will result from implementing the controls merited by a four-factor analysis.[10] Additional steps include regional scale modeling of the long-term strategy to set the RPGs for 2028 and progress, degradation, and URP glidepath checks.[11]

Some of the most problematic provisions of the Final Guidance, which are contrary to several requirements of the Regional Haze Rule and Clean Air Act, involve the selection of sources for analysis. After discussing these provisions, this Petition discusses the determination of affected Class I areas in other states, ambient data analysis, the characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, regional scale modeling of the long-term strategy to set the RPGs for 2028, progress, degradation, and URP glidepath checks, and additional requirements for regional haze SIPs. After addressing how these various provisions of the Guidance are contrary to the regulatory requirements, the Petition provides several overarching recommendations that EPA should consider when revising the Guidance, including advising states that in order for a SIP to be approvable it must result in measures to reduce visibility impairing pollution beyond those required from the past planning period and reflective of an adequate reasonable progress analysis.

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[8] Final Guidance at 5.
[9] *Id.*
[10] *Id*.
[11] *Id.* at 5-6.

III. Selection of sources for analysis

A. Selection of sources under section 51.308(f)(3)(ii)(A).

In the Final Guidance, EPA presents a statement at the beginning of the section II.B.3 that is in conflict with the Regional Haze Rule's requirements:

> A key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures. . . . Accordingly, it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods.[12]

This statement by EPA is contrary to the requirements in section 51.308(f)(3)(ii) of the Regional Haze Rule and section 169A(b) of the Clean Air Act.

In a footnote, EPA indicates that "analysis of control measures" refers to an analysis of what emission control measures for a particular source are necessary in order to make reasonable progress and must include consideration of the four statutory factors and consideration of the five additional factors listed in 40 C.F.R. § 51.308(f)(2)(iv).[13] This important requirement of how sources should be selected by states for analyses is presented as if it were a secondary consideration. In other words, EPA's Guidance now advises states that they can arbitrarily delay the selection of sources for evaluation, or exclude certain sources as noted *infra*, and thereby "distribute [their] analytical work" and the "compliance expenditures of source owners" as if it is a stand-alone, top-level decision that states can make, divorced of the need to apply the four statutory factors and the five additional factors to actually make reasonable progress.

If a state were to arbitrarily "distribute its own analytical work, and the compliance expenditures of source owners, over time"[14] as the guidance provides, it would not be able to address section 51.308(f)(3)(ii)(B), which requires:

> If a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State for which a demonstration by the other State is required under (f)(3)(ii)(A), the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to

[12] *Id.* at 9.
[13] *Id.* at 9 n.22.
[14] *Id.* at 9.

> include in its own long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy.

A state that arbitrarily excludes sources from consideration cannot determine if it actually has "sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area." To satisfy that requirement, a state must first have a reasonable understanding of the emissions from all of its sources and it must have a reasoned methodology for excluding sources from a four-factor analysis (e.g., those sources are inconsequential or do not have cost-effective control options). Similarly, if a state, which arbitrarily excludes sources from evaluation, has a RPG that is above the URP, it cannot satisfy section 51.308(f)(3)(ii)(A)[15], which requires that it demonstrate "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." In contrast, not only was this advice absent from EPA's Draft Guidance, the Draft Guidance provided detailed, valid information on source selection.[16]

Additionally, as mentioned *infra* section IV.A, the Final Guidance also arbitrarily allows states to decide whether they contribute to out-of-state Class I areas by claiming states can use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas.[17] The Final Guidance also allows a state to disregard its impacts on an out-of-state Class I area that a neighboring state may identify as being affected by emissions from the state developing the long-term strategy.[18] By allowing states to arbitrarily make these determinations, EPA is attempting to slice the program into inconsequential bits and pieces that set the

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[15] EPA noted in the 2017 Regional Haze Rule revision:

[I]n a situation where the RPG for the most impaired days is set above the glidepath, a contributing state must make the same demonstration with respect to its own long-term strategy that is required of the state containing the Class I area, namely that there are no other measures needed to provide for reasonable progress. The intent of this proposal was to ensure that states perform rigorous analyses, and adopt measures necessary for reasonable progress, with respect to Class I areas that their sources contribute to, regardless of whether such areas are located within their borders.

82 Fed. Reg. at 3099. *See also* 81 Fed. Reg. 66,331, 66,631 (Sept. 27, 2016) ("[A]n evaluation of the four statutory factors is required . . . regardless of the Class I area's position on the glidepath. . . . [T]he URP does not establish a 'safe harbor' for the state in setting its progress goals."); 81 Fed. Reg. 295, 326 (Jan. 5, 2016) ("[T]he uniform rate of progress is not a 'safe harbor' under the Regional Haze Rule"); EPA, Guidance for Setting Reasonable Progress Goals under the Regional Haze Program (hereinafter "RPGs Guidance") (June 2007) 4–1, https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.

[16] Draft Guidance at 57-83.

[17] Final Guidance at 8.

[18] *Id.* at 9.

provisions of the Final Guidance against fulfilling the requirements of the Clean Air Act and Regional Haze Rule that compel a comprehensive "regional" approach to restoring visibility. EPA should strike the above-mentioned language discussing selection of sources under section 51.308(f)(3)(ii)(A) from the Final Guidance and restore the language from the Draft Guidance.

B. States have only limited discretion to decide which sources they consider for reasonable progress.

In Section II.B.3.d of the Final Guidance, EPA states, "[t]he source-selection step is intended to add flexibility and discretion to the state planning process – ultimately, the state decides which sources to consider for reasonable progress."[19] This blanket statement, written as if a state has unbounded discretion to determine which sources it evaluates under reasonable progress, is incorrect. A state cannot arbitrarily determine which sources it evaluates under the Regional Haze Rule's reasonable progress requirements. Ultimately, a state's source selection criteria is a part of its long-term strategy. As EPA indicated in the Regional Haze Rule revision, a state does not have discretion to arbitrarily exclude sources from a four-factor analysis. Specifically, EPA stated:

> [W]e expect states to exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze. Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by arbitrarily including costly controls at sources that do not meaningfully impact visibility or failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a [Federal Implementation Plans ("FIPs")]. [20]

A state with a RPG below the URP that followed this guidance and arbitrarily excluded sources from a four-factor analysis runs afoul of section 51.308(f)(3)(ii)(A), which requires a "robust demonstration" that "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." If a state that followed this guidance had emission sources that potentially affect visibility at a Class I area in another state, it would similarly be unable to satisfy the same requirement found in section 51.308(f)(3)(ii)(B). EPA should reconsider this provision, and delete it from the Final Guidance.

C. States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.

[19] Final Guidance at 20.
[20] 82 Fed. Reg. at 3088.

In Section II.B.3.d of the Final Guidance, EPA also states "[i]f a source is expected to close by December 31, 2028, under an enforceable requirement, a state may consider that to be sufficient reason to not select the source at the source selection step."[21] EPA goes on to extend this deadline by adding an indeterminate grace period: "The year 2028 is not a bright line for these considerations, so a state may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028."[22] EPA further advises states that consideration of source retirement and replacement schedules required by Section 51.308(f)(2)(iv)(C) are automatically considered if a state decides to not subject sources which will retire by 2028 to a four-factor analysis.[23]

This is a departure from EPA's long-standing requirement in the regional haze program and is in conflict with basic requirements of the Regional Haze Rule. Remaining useful life is one of the four statutory factors that a state must consider when selecting the sources for which it will determine what control measures are necessary to make reasonable progress.[24]

The Clean Air Act does not define the phrase "remaining useful life." However, EPA, in regulations and guidance, has clarified the meaning of the phrase. EPA has consistently stated that the potential retirement of a facility can be used to shorten a source's remaining useful life only if the retirement is federally enforceable.[25] Thus, in order to affect the remaining useful life, a retirement commitment must be included in a pre-existing document that can be enforced in federal court, such as a consent decree entered by a federal court, or a state must incorporate the retirement date into its SIP. If a potential retirement is not federally enforceable, it cannot be relied upon to shorten the remaining useful life of a source.

EPA's 2007 Guidance on reasonable progress incorporates and refers to the best available retrofit technology ("BART") Guidelines,[26] which instruct states on how to calculate the remaining useful life of a source. EPA defines a source's "remaining useful life" as the difference between the date that controls would be installed and "the date the facility permanently stops

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[21] Final Guidance at 20.
[22] *Id.*
[23] *Id.* at 22.
[24] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("[A]n agency rule would be arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem."); *Pub. Citizen v. Fed. Motor Carrier Safety Admin.*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) ("A statutorily mandated factor, by definition, is an important aspect of any issue before an administrative agency, as it is for Congress in the first instance to define the appropriate scope of an agency's mission.").
[25] *E.g.*, 83 Fed. Reg. 62,204, 62,232 (Nov. 30, 2018) ( "We are proposing to agree with Arkansas' cost analysis for dry scrubbers and switching to low sulfur coal for Independence Units 1 and 2, and with the state's decision to assume a 30-year capital cost recovery period in the cost analysis. It is appropriate to assume a 30-year capital cost recovery period in the cost analysis since Entergy's plans to cease coal combustion at the Independence facility are not state or federally-enforceable."); 83 Fed. Reg. 43,586, 43,604 (Aug. 27, 2018) (Considering the retirement of certain units where there was evidence that the units had actually been retired at the time of the rulemaking and that the plant had requested cancellation of its air permit).
[26] RPGs Guidance at 5-3. There is no conflict with the 2007 Guidance's interpretation of "remaining useful life" and the Final Guidance. *See* Final Guidance at 34.

operations."[27] If the remaining useful life affects the selection of controls, "this date should be assured by a federally- or State-enforceable restriction preventing further operation."[28] EPA discusses a situation where a source "intends to shut down a source by a given date, but wishes to retain the flexibility to continue operating beyond that date in the event."[29] In that instance, EPA instructs a state to include in its SIP the controls that would be required if the source continues to operate past the planned retirement date.[30] "The source would not be allowed to operate after the 5–year mark without such controls."[31]

Allowing states to avoid a four-factor analysis based on alleged intent to retire would render the other statutory factors meaningless and violate the requirements of the Regional Haze Rule.[32] Many states have already begun analyzing their sources to determine which should be brought forward for a four-factor analysis. Consequently, a source that retires by December 31, 2028 (or later), has at least eight years of potential emission reductions. Even considering this shortened remaining useful life, cost-effective controls, which often can be installed in months, can frequently be justified. For instance, a source could simply switch to a lower sulfur content coal or fuel oil, which would require little to no installation time and may be quite cost-effective. Despite EPA's advice, any source that demonstrably or potentially impacts visibility at a Class I area and would otherwise be subject to a four-factor analysis under section 51.308(f)(2)(i), regardless of its retirement date, must undergo a real analysis to determine if cost-effective controls are available.[33] EPA should revise the Final Guidance to reiterate that only enforceable retirements may alter the remaining useful life and otherwise require that states subject sources that intend to retire to a four-factor analysis if a state selects the source for analysis of emission control measures.

D. States cannot consider being under the URP when selecting sources for a four-factor analysis.

In Section II.B.3.e of the Final Guidance, EPA makes two flawed statements regarding a state's RPG that were not present in the Draft Guidance. First, EPA states "[t]he fact that visibility conditions in 2028 will be on or below the URP glidepath is not a sufficient basis by itself for a state to select no sources for analysis of control measures; however, the state may

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[27] 40 C.F.R. pt. 51, App. Y § (IV)(D)(4)(k)(2).
[28] *Id.*
[29] *Id.* § (IV)(D)(4)(k)(3).
[30] *Id.*
[31] *Id.*
[32] The United States Court of Appeals for the Fifth Circuit recently found that EPA must consider statutory factors listed in a similar provision of the Clean Water Act when revising best available technology ("BAT") limits. *See Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999, 1026-27 (5th Cir. 2019).
[33] EPA's draft guidance also allowed for states to forgo a four-factor analysis on sources secured by an enforceable commitment to retire by 2028. We disagree with that position for the reason expressed above. However, EPA tempered its reasoning in its draft guidance by stating that its position rested on the fact that due to the shortened second planning period (unlike future planning periods), there would be a shorter interval for states to install controls. Also, EPA did not state that states could extend source retirements beyond 2028 as it does in the final guidance.

consider this information when selecting sources."[34] EPA then cites to the 2017 Regional Haze Rule revisions; however, those citations make it absolutely clear that states cannot in fact follow this guidance:

> We disagree that the states should be able to reevaluate whether a control measure is necessary to make reasonable progress based on the RPGs. The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures already determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. [35]

Consequently, states have no path available to them to "consider this information when selecting sources."

Similarly, EPA's later advice that "[r]ather, that fact [that a state's RPG is below the URP] would serve to demonstrate that, after a state has gone through its source selection and control measure analysis, it has no 'robust demonstration' obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B)"[36] is potentially at odds with the Regional Haze Rule. In the above cited portion of the 2017 Regional Haze Rule revision, EPA actually stated, "if a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line."[37] A state's "robust demonstration" obligation does not end because it has merely "gone through its source selection and control measure analysis." Rather, as EPA actually explained, the state must have "reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress." [38] EPA must reconsider this provision, and delete it from the Final Guidance.

E. Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.

In section II.B.3.f of the Final Guidance, EPA discusses circumstances under which a state can choose not to select a source that has previously installed controls for a four-factor analysis.[39] Much of this information conflicts with previous guidance and the Regional Haze

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[34] Final Guidance at 22.
[35] 82 Fed. Reg. at 3093. *See also* 81 Fed. Reg. at 66,631; 81 Fed. Reg. at 326; RPGs Guidance at 4-1.
[36] Final Guidance at 22.
[37] 82 Fed. Reg. at 3093.
[38] *Id.*
[39] *Id.* In comparison to the blanket exemptions in EPA's Final Guidance, the Draft Guidance only considered exempting power plant units, "in certain limited situations," with "highly effective control technology within the 5 years prior to submission of the SIP, such as year-round operation of flue gas desulfurization (FGD) with an

Rule. First, EPA states, "[i]n general, if post-combustion controls were selected and installed fairly recently . . . to meet a [Clean Air Act] requirement, there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions having been made in the intervening period."[40] EPA presents no basis for making this conclusion.

There are many instances in which post-combustion controls have been installed in which those controls do not operate at peak efficiency. This includes controls that are not operated continuously, controls that were never designed to operate at peak efficiency (e.g., undersized sulfur dioxide ("$SO_2$") scrubber or selective catalytic reduction ("SCR") systems) and partially bypassed controls (e.g., $SO_2$ scrubber or SCR systems). In fact, EPA has made it a point in past actions to ensure that existing controls are examined to determine if they can be cost-effectively upgraded. For instance, the 2005 BART revision to the Regional Haze Rule devotes several paragraphs to specific potential scrubber upgrades it recommends be examined.[41]

EPA also demonstrated that scrubber upgrades to a number of coal-fired power plants utilizing outdated and inefficient scrubber systems were highly cost-effective, and could achieve removal efficiencies of ninety-five percent which is near the ninety-eight to ninety-nine percent removal efficiencies of newly-installed scrubber systems.[42] In fact, as EPA notes in its 2017 Regional Haze Rule revision, EPA disapproved Texas' four-factor analysis in part because "it did not include scrubber upgrades that would achieve highly cost-effective emission reductions that would lead to significant visibility improvements."[43] Consequently, EPA's blanket guidance that examination of potential upgrades to recently installed post-combustion controls is unlikely necessary is demonstrably false. Even if, considering the entire universe of potential post-combustion control upgrades, the vast majority cannot be cost-effectively upgraded to result in significant visibility benefits, which is unlikely, there is no justification in the Regional Haze Rule to skip an examination of the remaining units.

EPA goes on to present examples of pollutant-specific controls that have been installed due to a requirement outside of the regional haze program for which it "believes it may be reasonable for a state not to select a particular source for further analysis."[44] This list includes new source performance standard ("NSPS") controls installed since July 31, 2013; best available control technology ("BACT") or lowest achievable emission rate ("LAER") controls installed since July 31, 2013; power plants with FGD controls that meet the 2012 model attainment test systems ("MATS") standard; particulate matter ("PM") controls under National Emission

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effectiveness of at least 90 percent or year-round operation of selective catalytic reduction with an effectiveness of at least 90 percent." EPA specifically requested comment "on whether to include this additional screening mechanism and if so, then what criteria may be appropriate for its inclusion."

[40] *Id.*

[41] *See* 70 Fed. Reg. 39,103, 39,171 (July 6, 2005).

[42] *See* 81 Fed. Reg. at 305.

[43] *See* 82 Fed. Reg. at 3088.

[44] Final Guidance at 23.

Standards for Hazardous Air Pollutants ("NESHAP") since July 31, 2013; boilers that have installed an FGD or SCR system that operates year round and has a total efficiency of ninety percent; and any BART-eligible unit that has installed BART controls.[45] EPA reasons that due to their recent installation and the similarity of the requirements for those programs, it is unlikely that a four-factor analysis will result in additional cost-effective controls.[46] But, as EPA notes in its 2005 BART revision to the Regional Haze Rule, it reviewed some of these standards and concluded they may not be the most stringent available.[47] Furthermore, the 2017 revision to the Regional Haze Rule warned states that "we anticipate that a number of BART-eligible sources that installed only moderately effective controls (or no controls at all) *will need to be reassessed*. Under the 1999 [Regional Haze Rule and] 40 CFR 51.308(e)(5), BART-eligible sources are subject to the requirements of 40 CFR 51.308(d), which addresses regional haze SIP requirements for the first implementation period, in the same manner as other sources going forward."[48] This is in contrast to EPA's Final Guidance statement that "if a source installed and is currently operating controls to meet BART emission limits, it may be unlikely that there will be further available reasonable controls for such sources."[49] Therefore, a state must first subject a source to a four-factor analysis under section 51.308(f)(2)(i) before it is able to determine whether there are no emission reducing options available (including upgrades to existing controls).

Regarding which control measures states should consider in assessing reasonable progress, EPA states "there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."[50] This conflicts with past guidance and with the Regional Haze Rule. Although there is no requirement that controls required under the reasonable progress requirements of the Regional Haze Rule uniformly be the most stringent available, not considering this level of control bypasses section 51.308(f)(2)(i), which requires that the state perform a four-factor analysis. A state cannot consider "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" unless it considers all feasible controls available, including upgrades to existing controls.

EPA acknowledged that a range of controls should be evaluated in a four-factor analysis in its Draft Guidance:

> In order to define a control measure with sufficient specificity to assess its cost and potential for emission reductions, the state should specify and consider the range of control efficiencies that the measure is capable of achieving. For example, when

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[45] *Id.* at 23-25.
[46] *Id.* at 25.
[47] *See* 70 Fed. Reg. at 39,163-64.
[48] 82 Fed. Reg. at 3083 (emphasis added).
[49] Final Guidance at 25.
[50] *Id.* at 29.

> evaluating a flue gas desulfurization system to reduce $SO_2$ emissions, the state should consider both a system capable of achieving a 90 percent reduction in $SO_2$ emissions as well as a more advanced system capable of achieving a 97 or 98 percent reduction. The state should not limit its analysis to either an unrealistically high and prohibitively expensive control efficiency or to a control efficiency that is substantially lower than has been achieved at other sources.[51]

Furthermore, EPA does not require that states secure the operation of controls with this level of efficiency through an enforceable commitment.

Just because a source has the most effective or highly effective control technology does not mean that it is required to be operated to a level reflective of its maximum pollution reduction capability. Thus, states should not be screening such sources out of review during the second implementation period. By allowing states to "screen out" and choose not to select such sources for a full four-factor analysis, EPA may be allowing states to ignore very cost-effective emission reducing options like simply requiring sources with highly effective controls to operate those controls in the most effective manner to reduce air pollutants. EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, reducing capacity, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, or requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

F. States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.

EPA should revise the Final Guidance to recommend that wherever possible, whether they are screened in or out, states should make sure that the emissions relied upon in the state's RPG demonstration are enforceable, and also that they reflect the lowest emission rates feasible at the facility given its existing configuration. This is particularly true for major sources that are screened out on the basis of emissions that reflect unenforceable conditions.

However, this is also true for sources that are screened out on the basis of emissions that do not reflect their full capacity for emission reductions. For example, if a source is screened out with emissions that reflect using its controls only seventy-five percent of the time, the state should nevertheless require year-round operation of the control. Requirements reflecting existing capacity for emission reductions are inherently reasonable, and represent low hanging fruit necessitating reduced resource expenditure for potentially large gain. Moreover, states routinely rely on actual emissions in assessing current visibility and using that assessment as a jumping off point to determine if additional reductions are necessary. Where a state is to rely on operational

[51] Draft Guidance at 87.

realities, such reliance must be justified by enforceable emission limits. Indeed, failing to take advantage of such reasonable progress measures is an example of one of the pitfalls of using this type of a screening process in the first place. EPA should recommend that states assure reasonable progress by requiring that sources have enforceable limits or conditions reflecting their full emission reduction capacity if they are to be screened out.

G. States must include both "dominant" and "non-dominant" pollutants in their analyses of controls.

In Section II.B.3.a of the Final Guidance, EPA advises states that they can skip analyses of controls for sources with "non-dominant" pollutants. Specifically, EPA states:

> When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors. Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants.[52]

This position, absent from the Draft Guidance, directs states to produce deficient regional haze SIPs and is in conflict with the Regional Haze Rule's requirements and preamble language in the 2017 Regional Haze Rule revision.

The preamble specifically states that a "reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by . . . *failing to include cost-effective controls at sources with significant visibility impacts*, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP.[53] This provision in the Guidance would allow states to arbitrarily determine that because one pollutant has a greater impact on visibility at a Class I area(s), the state may simply ignore other visibility impacting pollutants for one or all sources in the state emitting the non-dominant pollutants, despite the availability of cost-effective controls under reasonable progress criteria. It would also allow states to conclude that when examining a source that emits multiple pollutants that contribute to haze (e.g., $SO_2$, Nitrogen Oxide ("NOx")), potential reductions for the non-dominant pollutant can be summarily ignored. Furthermore, EPA does not provide any metric for what it considers a "dominant" pollutant.[54] For instance, if a state has determined that fifty-one percent of the visibility impact at a Class I area is due to $SO_2$, forty

[52] Final Guidance at 11.
[53] 82 Fed. Reg. at 3088. EPA states elsewhere in its 2017 Regional Haze Rule revision, that "A state may refer to its own experience, past EPA actions, the preamble to this rule as proposed and this final rule preamble, and existing guidance documents for direction on what constitutes a reasoned determination." 82 Fed. Reg. at 3099.
[54] Merriam-Webster defines dominant as "(a) commanding, controlling, or prevailing over all others," or as "(b) very important, powerful, or successful."

percent is due to NOx, and nine percent is due to PM, would $SO_2$ be considered dominant (and consequently the only analyzed pollutant), or must its share of the visibility impact be greater?

This provision in the Final Guidance has potentially far-reaching negative impacts on the Regional Haze Rule's requirements that states make reasonable progress, as many large sources emit multiple types of visibility impacting pollutants. Still other sources may emit significant levels of non-dominant emissions for which emission reducing control or measures may be well within the framework of the four-factor analysis. If this is not corrected, a state could assume it would be justified in concluding that state-wide, $SO_2$ is its "dominant" pollutant and forego control analysis of a large gas-fired power plant emitting thousands of tons of NOx which could also significantly impact visibility at one or more Class I areas.

The Final Guidance also directly conflicts with multiple sections of the Regional Haze Rule. For instance, a state following the guidance would not be able to determine if it was even subject to section 51.308(f)(3)(ii)(B), because by arbitrarily excluding pollutants or entire sources from review it could not determine if it "reasonably [was] anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State." Nor could that state "demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Similarly, if that state's RPG was above its URP, it could not satisfy section 51.308(f)(3)(ii)(A), which requires the same demonstration. Such a state would also not be able to reasonably satisfy its state-to-state consultation requirements under section 51.308(f)(2)(i), which requires it to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress" and "include 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." By severely compromising the entire foundation of a state's technical demonstration, EPA is directing states to submit deficient SIPs. For these reasons, EPA should delete the above-quoted language from the Final Guidance.

H. States cannot eliminate VOCs and ammonia emissions from consideration.

In Section II.B.3.a. of the Final Guidance, EPA also advises states that irrespective of their particular state emissions inventories or the acknowledged potential impacts of VOCs and ammonia on Class I areas, they can completely disregard these pollutants. Specifically, EPA states:

> In the first implementation period, many states eliminated VOC and ammonia emissions from consideration based on the expectation that anthropogenic VOC emissions make only a small contribution to visibility impairment and that formation of nitrate and sulfate PM is most effectively reduced by reducing emissions of NOx and $SO_2$ rather than by anthropogenic emissions of ammonia. EPA believes that, in general, this

> would also be a reasonable approach for the second implementation period.[55]

This position is completely absent from EPA's regulations and was not present in the Draft Guidance.

VOCs are organic chemicals emitted by products or industrial processes that when released into the atmosphere can react with sunlight and NOx to form tropospheric ("ground-level") ozone. In addition, VOCs are important precursor of Secondary Aerosol Formation ("SOA"). SOA comprises a large fraction of atmospheric aerosol mass and can have significant effects on atmospheric chemistry, visibility, human health, and climate.[56] A major source of VOCs in the United States is the oil and gas industry, which includes wells, gas gatherings and processing facilities, storage, and transmission and distribution pipelines. According to data from EPA and the Energy Information Agency ("EIA"), more than 20 million tons of VOCs are emitted from point and non-point sources in the oil and gas industry every year. Studies on oil and gas emissions have indicated that VOC source signatures associated with oil and gas operations can be clearly differentiated from urban sources dominated by vehicular exhaust emissions.[57][58] According to a recent air quality study by the National Park Service ("NPS") in Carlsbad Caverns National Park, high levels of light alkanes such as ethane, propane, butane, and, pentane compounds were consistent with oil and gas emissions. However, high alkanes ("$>C_8$") and aromatics are assumed to contribute more significantly to SOA formation.[59]

In California alone, statewide agricultural operations produce an average of 272.12 tons per day ("tpd") of ammonia ("$NH_3$") emissions.[60] Of those 272.12 tpd, 158.50 tpd is attributed to "agricultural waste" specifically from dairy cattle.[61] In regions such as California's heavily polluted San Joaquin Valley, ammonia concentrations are found to be much higher than NOx

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[55] Final Guidance at 12.
[56] Ziemann, Paul J., & R. Atkinson, *Kinetics, products, and mechanisms of secondary organic aerosol formation*, 41, no. 19 Chem. Soc'y Reviews 6582, 6582 (2012).
[57] *See* Odum J.R., T. Hoffmann, F. Bowman, D. Collins, R.C. Flagan, & J.H. Seinfeld, *Gas/Particle Partitioning and Secondary Organic Aerosol Yields*, 30 Environ. Sci. Technol., 2580, 2580-2585 (1996).
[58] *See* Swarthout, R. F., Russo, R. S., Zhou, Y., Hart, A. H., and Sive, B. C., *Volatile organic compound distributions during the NACHTT campaign at the Boulder Atmospheric Observatory: Influence of urban and natural gas sources*, J. Geophys. Res. Atmos., 118, 10,614–10,637, (2013), *available at* https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/jgrd.50722.
[59] Ziemann, *supra* note 56, at 6583; *see also* Takekawa, Hideto, Hiroaki Minoura, and Satoshi Yamazaki, *Temperature dependence of secondary organic aerosol formation by photo-oxidation of hydrocarbons*, Atmospheric Environment 37, no. 24, 3413-3424 (2003).
[60] California Air Resources Board, 2016 SIP Emission Almanac Projection Data by EIC: Annual Average Emissions (Tons/Day) Statewide, Miscellaneous Processes 620-Farming Operations, https://www.arb.ca.gov/app/emsinv/2017/emseic_query.php?F_YR=2012&F_DIV=-4&F_SEASON=A&SP=SIP105ADJ&SPN=SIP105ADJ&F_AREA=CA&F_EICSUM=620.
[61] *Id.*

concentrations.[62] When mixed with the region's NOx emissions (primarily from mobile sources), this excess ammonia helps form high levels of haze causing ammonium nitrate, which accounts for the majority of PM2.5 emissions found in the San Joaquin Valley.[63]

The San Joaquin Valley is home to multiple communities such as Bakersfield, Fresno, and Visalia that rank amongst the very topmost polluted cities for both annual and twenty-four hour PM2.5 pollution. [64] The entire air basin is also listed as being in extreme nonattainment with the 1997 and 2006 PM2.5 NAAQS standards.[65] As it relates to regional haze pollution, the San Joaquin Valley is located directly adjacent to the Southern Sierra Nevada Mountains, home to heavily polluted Class 1 areas like Sequoia and Kings Canyon National Parks—both of which fall within the jurisdiction of the San Joaquin Valley Air District.

Despite ammonia being a major precursor to PM2.5 pollution in the region, its emissions are currently not controlled in the San Joaquin Valley under the state's various PM2.5 SIPs.[66] Beyond ammonia, agricultural sources in California also produce and average of 145.90 tpd of direct PM10 and 21.79 tpd of direct PM2.5 emissions.[67]

In its 2005 BART amendments to the Regional Haze Rule, EPA left it to the states to individually determine if these two pollutants, which EPA acknowledges can potentially impact visibility, should be addressed.[68] In the Draft Guidance, EPA acknowledged that much of its guidance on BART remained applicable to the second round of SIPs and included an entire appendix devoted to identifying which portions of the BART guidance remained applicable.[69] This appendix has been deleted in EPA's Final Guidance. By arbitrarily excluding potential visibility-impairing pollutants from review, EPA's guidance conflicts with the same sections of the Regional Haze Rule as described *supra* section III.G, primarily preamble language to the 2017 Regional Haze Rule revision and sections 51.308((f)(3)(ii)(A), 51.308((f)(3)(ii)(B), and 51.308(f)(2)(i). EPA should revise the Final Guidance to direct states to inventory and evaluate potential visibility-impairing pollutants including VOCs and ammonia and determine associated control measures necessary to make reasonable progress. .

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[62] San Joaquin Valley Air Pollution Control District, 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards, at 5-6, http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.
[63] *Id.* at 3-12.
[64] American Lung Association, 2019 State of the Air Report: Most Polluted Cities Ranking, https://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/most-polluted-cities.html.
[65] San Joaquin Valley Air Pollution Control District, *supra* note 62, at ES-8.
[66] *See generally, id.* at 4-1 through 4-34.
[67] *See* California Air Resources Board, *supra* note 60.
[68] *See* 70 Fed. Reg. 39,104, 39,112-14 (July 6, 2005). EPA stated that scientific and technical data shows "that ammonia in the atmosphere can be a precursor to the formation of particles such as ammonium sulfate and ammonium nitrate . . . [and] certain aromatic VOC emissions such as toluene, xylene, and trimethyl-benzene are precursors to the formation of secondary organic aerosol." *Id.* at 39,114.
[69] Draft Guidance at Appendix D.

I. Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.

States choosing light extinction as a metric for visibility impacts should use Class I-specific figures to identify sources for a four-factor analysis. If a threshold is applied, states must ensure that the threshold is low enough to bring in most sources harming a Class I area. In the Final Guidance, EPA recommends visibility metrics and thresholds in terms of inverse megameters of light extinction.[70] Although light extinction may be acceptable as a metric, states should not use a generic extinction threshold for selecting sources for consideration of pollution controls for each of the Class I areas evaluated in their regional haze SIPs. If a light extinction threshold is too high, it can significantly limit the amount of sources a state evaluates for controls to make reasonable progress.

States must make clear how each source's visibility impacts are to be determined. States must explain whether the sources' potential emissions were modeled, what visibility-impairing pollutants were modeled for each source, whether all units were modeled for all sources, whether sources were modeled for impacts on the twenty percent worst days or some other timeframe, and identify and allow public review of and comment on the technical approach that the state employed to determine source-specific visibility extinction, pursuant to 40 C.F.R. § 51.308(f)(2). Any proposed extinction threshold for defining sources to target for controls is only as good as the underlying technical analysis to define if a source exceeds the extinction threshold. States must address these requirements and justify any and all extinction thresholds that they rely on for each Class I area impacted by states' sources.

For any souces that exceed an extinction threshold but are not subject to reduction requirements, states should provide a thorough four-factor analysis of controls or provide justification as to why a four-factor analysis would not likely lead to a determination that additional controls are needed to make reasonable progress. For any sources that a state claims already has adequate controls or justifies for other reasons that a four-factor analysis of controls would not result in additional controls, the state must document in its regional haze SIP why it makes this finding. To the extent such justification is relying on other regulatory or permit requirements, the state must document those regulatory or permit requirements in detail and indicate whether such requirements are already or will be submitted to EPA as part of the SIP

J. State's using the Q/d metric should include all visibility-impairing pollutants when calculating a source's annual emissions.

In Section II.B.3.b of the Final Guidance, EPA discusses the use of a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts, along with a reasonably selected threshold for this metric.[71] As EPA notes, although Q/d is the least

[70] Final Guidance at 19.
[71] Final Guidance at 13.

complicated technique, it should "be limited to source selection for the purpose of developing a list of sources for which a state may conduct a four-factor analysis" because the metric is a less reliable indicator of actual visibility impact.[72]

EPA should revise the Final Guidance to require states using the Q/d metric to include all visibility-impairing pollutants when determining the annual emissions being used to obtain a source or source category's estimated visibility impacts. As discussed further *supra* section III.H, states cannot eliminate certain emissions, such as VOCs and ammonia emissions, from consideration. Additionally, EPA should recommend that states using the Q/d metric not use the Q/d threshold from the first implementation period for the second implementation period. Rather, the Q/d threshold should be lower in order to address more sources, including sources that are lower emitting and sources that are further in distance than the sources addressed in the first implementation period.

## IV. Determination of affected Class I areas in other states

### A. States must use methods permitted by statute and regulation to identify its sources that impact visibility at Class I areas in other states, not merely any "reasonable method."

In Section II.B.2 of the Final Guidance, EPA inserts a blanket statement that jeopardizes making progress towards the Clean Air Act Class I visibility goal and obfuscates the Regional Haze Rule's requirements regarding how a state should identify its sources that impact the visibility at Class I areas in other states: "As an initial matter, a state has the flexibility to use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas, and it may use any reasonable assessment for this determination."[73]

EPA does not provide any explanation or examples of what it considers "reasonable." Thus, this statement would allow a state to use any methodology, regardless of its scientific rigor, to identify those sources. Furthermore, once having identified these sources, however loosely, the state can then "assess" those sources any way it wishes. Confusingly, EPA seems to distinguish between quantifying the impacts of these sources and assessing these impacts. This single statement would serve to hand a state seemingly unlimited discretion over a key step in preparing its SIP, in marked contrast to what it proposed.

As EPA states in its 2017 Regional Haze Rule revision:

> On July 8, 2016, we released Draft Guidance that discusses how states can determine which Class I areas they ''may affect'' and therefore must consider when selecting sources for inclusion in a four-factor analysis. The Draft Guidance discusses various approaches that states used during the first implementation

[72] *Id.*
[73] Final Guidance at 8.

> period, provides states with the flexibility to choose from among these approaches in the second implementation period, and recommends that states adopt ''a conservative . . . approach to determining whether their sources may affect visibility at out-of-state Class I areas.[74]

Indeed, EPA's Draft Guidance did provide actual guidance to the states on this issue:

> Once contributions by sources, groups of sources or geographic areas have been quantified in some manner, the EPA recommends that states adopt a conservative (more protective approach of visibility) approach to determining whether their sources may affect visibility at out-of-state Class I areas. For example, states could consider all Class I areas for which the state contributes at least one percent to anthropogenic light extinction from all U.S. sources on any day within the 20 percent most impaired days. States may choose a different threshold to determine which out-of-state Class I areas may be affected by the States sources, but must provide an adequate explanation of why the threshold is sufficiently protective of visibility.[75]

EPA followed this statement with more than twelve pages of highly technical guidance detailing approaches it deemed acceptable.[76] The Final Guidance deletes most of this and provides a summary approach void of technical rigor or analytical teeth. The Regional Haze Rule makes plain that a state's long-term strategy, including its application of the four statutory factors, be comprised of a robust initial step—the assessment of the state's emission sources on downwind states' Class I areas. However, by diminishing actual guidance and inventing this undefined and ambiguous standard, EPA creates confusion and ambiguity for states, leaving states to determine reasonability on a SIP-by-SIP basis. EPA should restore the discussion and directives to states from the Draft Guidance.

B. Application of a threshold for cumulative impacts to multiple Class I areas.

EPA should reconsider and revise the Final Guidance to recommend that states quantitatively document the results of the screening process for each Class I area rather than presenting only the impacts at the most affected or nearest Class I area. This allows the public to know the scope of the source's impacts and assures that the SIP comports with the letter and spirit of the regional haze program, a program grounded in the fact that regional haze is a regional problem and that Class I area impacts are felt typically by a multitude of sources' pollution that defy state boundaries.

EPA should also make clear that states must consider cumulative impacts of sources or groups of sources to all affected Class I areas. A source's cumulative impacts across Class I

[74] 82 Fed. Reg. at 3094.
[75] Draft Guidance at 58.
[76] Draft Guidance at 58-70.

areas provides a valuable screen to identify sources for further analysis. As EPA conceded and the court found in *Nat'l Parks Conservation Ass'n v. EPA*, in considering the visibility improvement expected from the use of controls, states must take into account the visibility impacts at all impacted Class I areas rather than focusing solely on the benefits at the most impacted areas.[77] This must include sources that have relatively small impacts in isolation but larger cumulative impacts either in the aggregate or across Class I areas.

V. Ambient data analysis

A. States must prioritize emissions within their borders to achieve reasonable progress.

International emissions contribute to visibility impacts. Rather than encouraging states to pursue an adjustment to the end goal of natural visiblity due to international emissions, EPA should be directing states to focus on the emissions within their borders for which requirements would help achieve reasonable progress. We encourage EPA to work with states, FLMs, stakeholders, and other countries to develop emissions inventories for cross-border pollution as well as scientifically valid methods for assessing long range emissions transport. However, the development of accurate accounting and modeling should not come with the expense of postponing or ignoring domestic emission-reducing measures. EPA's updated 2028 modeling[78] attempts to incorporate international emissions, but the agency itself makes clear that the science upon which the modeling rests is questionable.[79] EPA should reconsider and revise its Guidance to clarify that assessing international emissions is a work in progress and opportunity for partnership across a broad set of stakeholders, but the mandate of the Clean Air Act compels states to take measures to make reasonable progress by reducing emissions in their borders, not look to analysis to excuse doing so because other nations also contribute to regional haze.

We also urge EPA to revise the Final Guidance to clarify that affected states also have an obligation to take appropriate action to address international emissions.[80] Although EPA and the states are not required to "compensate" for international emissions, it is well within EPA and the states' rights and obligations to formally request reductions from international sources where appropriate, or to take permitting actions in the United States that will lead to emission reductions in other countries.

For example, Mexico's Carbon I and II power plants, which are less than twenty miles from the Texas border, are responsible for significant levels of pollution across several of the border states. Despite noting the significant impact of Mexican sources on its Class I areas, and

[77] *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 165 (3d Cir. 2015).
[78] EPA, Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling (Sept. 19, 2019), https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf ("Updated 2028 Modeling").
[79] *Id.* at 67.
[80] 64 Fed. Reg. 35,714, 35,755 (July 1, 1999) ("The States retain a duty to work with EPA in helping the Federal government use appropriate means to address international pollution transport concerns.").

requesting federal efforts to reduce impacts from international emissions,[81] Texas approved water discharge and mining permits for a coal mine in Maverick County. Rejecting these permits instead would have prevented the Mexican company Dos Republicas from mining high-sulfur coal that is transported and burned at the Carbon I & II facilities. EPA should remove its false implication that international emissions are entirely "uncontrollable" and should instead make clear that states must demonstrate that they are doing what is within their control to address international emissions—both generally and in particular.

EPA also discusses an "adjustment" to the URP for prescribed wildland fires. Wildfires, particularly in the West, have grown hotter, bigger, and more frequent with climate change. We recognize the role of prescribed fire in both managing fire size due to climate impacts and in restoration of natural ecosystems—which can, if effective, reduce the size and scale of fires later. There are, as a result of increased prescribed fire, potential benefits to both short- and long-term air quality. In planning for prescribed wildland fires, states should consider effects on visibility, alongside health and other concerns, including potential control measures and the potential benefits. A State cannot adjust a URP based on prescribed fires unless these fires actually result in visbility impairment on the "most-impaired" days. The Final Guidance should be clear that analysis of and planning for prescribed wildland fires need to be tailored to the planning period basis and would not automatically apply to the next planning period.

## VI. Characterization of factors for emission control measures

### A. States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

In Section II.B.4.a of the Final Guidance, EPA advises states that they have the flexibility to reasonably determine which control measures to evaluate, and the agency lists examples of types of emission control measures states may consider.[82] EPA should reconsider its approach to ensure that the best controls for a source or source category are identified, evaluated, and the appropriate option determined. Identification of all available control measures is an important first step to ensure the best controls or emission reduction measures emerge from a four-factor analysis. However, EPA should revise the Final Guidance to ensure evaluation of the best control options.

#### 1. EPA should reiterate and expand upon Step 1 of the BART-Guidelines regarding the identification of all available emission control techniques.

EPA should encourage states to consider various sources of information and types of emissions control techniques in developing its long-term strategy. Specifically, EPA should make clear that states must look to new source review control technology determinations, including major source BACT and LAER determinations, as well as state minor source BACT

[81] Texas Revisions to the State Implementation Plan (SIP) Concerning Regional Haze, at ES-2 (Feb. 25, 2009).
[82] Final Guidance at 29-30.

determinations. EPA should also recommend that states evaluate technologies that were considered in applicable new source performance standards, as well as those emission controls that were required in applicable new source performance standards.[83] EPA should also recommend that states consider the control techniques evaluated and required for similar source BART determinations.

In addition, EPA should recommend that states consider BACT determinations and other new source control requirements that states have adopted in minor new source review permits. Several states have minor source BACT provisions which may provide useful information for control technology considerations, and/or states have adopted targeted emission control requirements for source categories that do not have parallel federal requirements.[84]

Further, EPA should recommend that states investigate controls for source categories evaluated in reasonably available control measures ("RACM")/ reasonably available control technology ("RACT") and best available control measures ("BACM")/BACT determinations for nonattainment areas, a good starting point for information for control techniques available for a particular source category. States should also be encouraged to consult vendors or vendor groups such as the Institute of Clean Air Companies for control techniques for sources or source categories.

States should consider inherently lower-emitting processes, by themselves, and in combination with add-on controls. A state should not reject a combination of control measures altogether when the control measures could also be applied independently, unless the state is instead focusing on a control measure that is more effective at reducing emissions than the individual control measures.

In general, EPA should provide flexibility for states to consider innovative technologies tied to quantifiable and enforceable emission reduction requirements and to consider control techniques that some could view as "redefining the source" such as a change in fuel form. The BART Guidelines seemed to limit such controls from consideration for BART. Setting aside whether this was appropriate for BART determinations, States should not be constrained when evaluating measures to consider for the long-term strategy to make reasonable progress towards the national visibility goal.

In evaluating measures for the long-term strategy, states may need to address sources that were constructed many decades ago and/or sources to which pollution controls have not typically

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[83] As EPA acknowledges in the BART guidelines, the NSPS standards do not always require the most stringent level of available control technology for a source category. 40 C.F.R. Part 51, Appendix Y, Section IV.D.2. In some cases, EPA evaluates more stringent controls in an NSPS proposed rulemaking, but ultimately requires a less stringent control to set the NSPS standard. EPA should make clear that NSPS standards are likely insufficient for purposes of reasonable progress determinations because the standards will not be reflective of the reduction measures available and otherwise meeting the four factors as SIPs are being advanced.

[84] *See, e.g.*, Colorado Regulation No. 7 – Control of Ozone via Ozone Precursors and Control of Hydrocarbon via Oil and Gas Emissions, https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=8546&fileName=5%20CCR%201001-9.

been applied. There may be little experience with applying pollution controls to such sources. However, the lack of information on "available" control technologies should not be used as a justification to eliminate a source from consideration of controls (or to only evaluate less effective controls). In such cases, States should be encouraged to consider innovative technologies, technologies that may not have historically been applied to the source type but could be transferred to the source type, emission unit replacement with more energy efficient/less polluting technology, and other such measures in evaluating how to best reduce haze-forming pollution from the source or source type.

2. EPA should advise states how to determine "available" and "technically feasible" control techniques for long-term strategy measures.

EPA should elaborate on how to determine whether a control technique is considered "available" or "technically feasible" for a source or source category. Section IV(D)(1) of the BART Guidelines[85] states in part that that "available retrofit control options are those with a practical potential for application to the emissions unit . . ." and "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice." EPA should recommend that states take a broader view in determining what control strategies are "available" for a source or source category, especially if traditional pollution controls had not been historically applied to that source category. In such cases, states may need to examine more innovative options for pollution control at such sources or source categories, including the consideration of promising pollution control options that have not already been demonstrated in practice but which offer quantifiable emission reductions.

Section IV(D)(1) of the BART Guidelines includes provisions to determine whether a control option is "technically feasible." Those provisions, as well as the discussion on available technologies, generally track guidance on evaluations for BACT determinations set out in EPA's New Source Review Workshop Manual.[86]

Sources often make availability or technical infeasibility arguments to avoid having to consider a pollution control, pointing out that that the control has not been used on the specific type of coal the source utilizes or on the particular size plant. Given that states may be having to determine controls for sources or source categories that have not been traditionally controlled in the long-term strategies, EPA should encourage states in such situations to fully evaluate controls that can be transferred from other source categories or that can be altered to accommodate the specific source or source category in question. EPA should recommend in such situations that states consult with, for example, environmental consultants, research technical journals, or air pollution control conference articles. States should also consider technologies demonstrated outside of the United States. EPA's New Source Review Workshop Manual describes how to

[85] 40 C.F.R. § Pt. 51, App. Y.
[86] U.S. EPA, New Source Review Workshop Manual, at B.17-B.21 (Draft Oct. 1990).

identify all control options "with potential application to the source and pollutant under evaluation."[87]

In summary, EPA should reconsider and revise the Final Guidance to elaborate on how states should evaluate available and technically feasible control techniques with the goal of ensuring that all potential controls with a practical application to a source or source category are considered in the development of the long-term strategy.

B. Cost analyses for the long-term strategy.

1. States must adhere to the accounting principles of the Control Cost Manual.

EPA should require states to follow the accounting principles and generic factors of EPA's Control Cost Manual because states and EPA have historically determined whether the costs of control measures are "reasonable" based on the costs that other similar sources determined in other regulatory actions including permits. [88] If EPA does not require all states to use the same accounting principles, it will be extremely difficult to compare costs of control between sources to evaluate whether the controls are cost effective.

2. States should compile and make publicly available the documentation for generic cost estimates.

EPA's Final Guidance suggests that states may reduce time and effort in determining control costs by using generic cost estimates or estimation algorithms, such as the Control Strategy Tool.[89] However, we request that EPA require the documentation for such generic cost estimates to be compiled and made publicly available. As stated in Sierra Club and National Parks Conservation Association's comments on EPA's proposed revisions to the Control Cost Manual, the Integrated Planning Model's SCR cost database is based on Sargent & Lundy's confidential database and the underlying data and methods used to develop the regression equations have not been publicly reviewed and analyzed.[90] Given that the cost estimates may be a primary basis for rejecting a control measure, the underlying data for such cost estimates must be publicly available.

C. EPA should reconsider and revise the Final Guidance regarding how to address energy and non-air quality environmental impacts of control measures.

EPA should state that the third factor of energy and non-air quality environmental impacts should generally be based on the same methodology laid out in the BART Guidelines. Section 8.1.1 of the BART Guidelines indicates that states must consider the energy and non-air quality environmental impacts as part of the cost analyses. With respect to taking into account non-air quality environmental impacts, we agree in general to take into account such impacts in

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[87] *Id.* at B.10-B.11.
[88] Final Guidance at 31.
[89] *Id.* at 32.
[90] *See* September 10, 2015 Comment Letter from Sierra Club and National Parks Conservation Association to U.S. EPA, Docket ID No. EPA-HQ-OAR-2015-0341, at 8.

the cost analysis if the costs can be quantified. Otherwise, such impacts may need to be discussed qualitatively and weighed in the four-factor analysis.

EPA should also revise the Final Guidance and recommend that states analyze the climate and environmental justice impacts of regional haze SIPs. Although the Regional Haze Rule does not define "non-air quality environmental impacts," the BART Guidelines, which inform a state's reasonable progress analysis, explain that the term should be interpreted broadly.[91] Climate change[92] and environmental justice[93] impacts are the types of non-air quality impacts that states should consider when they determine reasonable progress measures for specific sources. Incorporating climate change and environmental justice impacts into the regional haze analysis will further states' climate and environmental justice policy goals, and it will also help states ensure that their actions related to regional haze planning support their other work on climate and environmental justice issues. Most of the same sectors and sources implicated under the regional haze program are also implicated in climate and environmental justice initiatives. As a result, when states determine "the emissions reduction measures that are necessary to make reasonable progress," they should assess how those measures will either reduce or exacerbate greenhouse gas emissions and/or environmental justice impacts on nearby disproportionately burdened communities.

## VII. Decisions on what control measures are necessary to make reasonable progress

### A. States cannot allow sources to discontinue the use of currently operating controls.

In Section II.B.5.e of the Final Guidance, EPA advises states how currently controlled sources may be able to discontinue those controls under reasonable progress:

> It is also possible that a source may be operating an emission control device but could remain in compliance with applicable emission limits if it stopped operation of the device. The state may reasonably consider based on appropriate factors whether continued operation of that device is necessary to make reasonable progress, such that the regional haze SIP submission for the second implementation period must make such operation of the device (or attainment of an equivalent level of emission control) enforceable.[94]

Suggesting to states that they may discontinue the use of controls that are already operating is antithetical to the regional haze program. Rather, EPA should revise the Final Guidance to require states to evaluate more effective operation of existing controls, including year-round

[91] 40 C.F.R. pt. 51, App. Y at § (IV)(D)(4)(i), (IV)(D)(4)(j).
[92] *See, e.g.*, 74 Fed. Reg. 66,496 (Dec. 15, 2009) (EPA endangerment finding); Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2015), https://www.ipcc.ch/report/ar5/syr/.
[93] *See* EPA, Learn about Environmental Justice, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (last visited April 24, 2020); Exec. Order No. 12,898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 Fed. Reg. 7629 (Feb. 11, 1994).
[94] Final Guidance at 43.

operation requirements. Further, the Clean Air Act is clear that visibility is not a factor in determining reasonable progress measures required at a source.

In evaluating controls for a source that already had a control installed, such as a wet or dry scrubber for $SO_2$ or SCR or selective non-catalytic reduction ("SNCR") for NOx, states must be required to evaluate whether these controls can be more effectively operated. Companies tend to operate their air pollution control systems to the level needed to ensure compliance with applicable emission limits rather than to the maximum emission reduction capability of the pollution control technology. For example, there are electrical generating units ("EGUs") that are only operating their installed SCR or SNCR systems during the ozone season to meet limits under the Cross State Air Pollution Rule ("CSAPR"). Indeed, in projecting operations and emissions scenarios for evaluating the CSAPR program, EPA included assumptions for dispatchable SCR, SNCR, and also scrubbers, which reflected the fact that no emission limits or consent decrees required continuous operation of the pollution controls installed at many EGUs. EPA should thus recommend that states, at a minimum, require year-round operation of existing scrubbers, SCRs, SNCRs, or other controls as one of the control options considered.

Additionally, there are numerous examples of scrubbers, SCRs, and SNCRs that, when operated, are not operated to achieve the maximum emission reductions that could be accommodated within the existing control technology at a particular unit, primarily because the applicable emission limitation does not require operation of those pollution controls to achieve the maximum emission reductions. As mentioned *supra* section III.E, states should consider sources that already have in place the most stringent controls available for additional control in the development of the long-term strategy during the second implementation period.

EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, and requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

## VIII. Regional scale modeling of the long-term strategy to set the RPGs for 2028

### A. States should use regional scale modeling to support their regional haze SIPs.

In Section II.B.6 of the Final Guidance, EPA advises states that they are not required to use regional scale modeling to support their regional haze SIPs. Specifically, under Step 6, EPA states that a state must:

> Determine the visibility conditions in 2028 that will result from implementation of the LTS and other enforceable measures to set the RPGs for 2028. Typically, a state will do

> this through regional scale modeling, *although the Regional Haze Rule does not explicitly require regional scale modeling*.[95]

Were a state to forego estimating source or source categories emitting visibility-impairing pollutants, as the guidance provides, it would not be able to satisfy a number of basic requirements of the Regional Haze Rule. Estimating the visibility impacts from a collection of sources is a prerequisite of establishing a state's RPG. As EPA explains in its 2017 Regional Haze Rule revision, this is a key first step in a state setting its RPG: "the 2007 guidance clearly describes the goal-setting process as starting with the evaluation of control measures. First, we recommended that states '[i]dentify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area.'"[96] If a state did not estimate the visibility impacts from source or source categories, it could not satisfy the requirement in Section 51.308(f)(3)(ii)(A) that it demonstrate, "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Indeed, this misplaced advice is not even internally consistent with other sections of the Final Guidance, which cover many techniques for estimating the visibility impacts of sources or source categories. Estimating the collective visibility impacts of sources or source categories to determine the RPG is a fundamental requirement of the regional haze program.

In fact, there is no known substitute for the use of photochemical air quality models to project the visibility impact from thousands of individual sources, influenced by complex meteorological fields and atmospheric chemical interactions at a Class I area, ten years into the future, as EPA makes clear in Appendix W to Part 51.[97] The use of air quality models has been a cornerstone of the technical demonstration of the regional haze program (and many other air programs) since its inception. Almost every EPA Regional Haze Rule revision and guidance either discusses the use of air quality models or assumes their use. In fact, EPA recently updated its modeling guidance for regional haze.[98] The very first sentence of the section specifically devoted to regional haze is: "[t]his section focuses on the modeling analysis needed to set RPGs that reflect the enforceable emission limitations, compliance schedules, and other measures included in the long-term strategy of a regional haze SIP."[99] Part 51 makes it clear that air quality

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[95] Final Guidance, Table 1, at 6 (emphasis added).
[96] *See* 82 Fed. Reg. at 3092-93. Notably, EPA does not abandon its 2007 Guidance and in fact refers to in several places in its rule revision.
[97] *See* 40 C.F.R. Pt. 51; App. W, Section 2.0 (a), "Guideline on Air Quality Models," ("Increasing reliance has been placed on concentration estimates from air quality models as the primary basis for regulatory decisions concerning source permits and emission control requirements. In many situations, such as review of a proposed new source, no practical alternative exists."); *see also id.* at Section 1.0 (b), ("The impacts of new sources that do not yet exist, and modifications to existing sources that have yet to be implemented, can only be determined through modeling.") This is precisely the challenge of setting RPGs – accounting for modifications to potentially dozens of existing sources (e.g., installation of controls).
[98] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.s and Regional Haze, EPA 454/R-18-009, (Nov. 2018).
[99] *Id.* at 143.

modeling is a necessary tool in the setting of RPGs and EPA should not imply otherwise in its guidance.

Instead of guiding states on modeling, EPA repeatedly informs states that they can use "surrogates" to estimate visibility impacts of a body of sources. Specifically, EPA states that "the Regional Haze Rule does not require states to develop estimates of individual source or source category visibility impacts, or to use an air quality model to do so. Reasonable surrogate metrics of visibility impact may be used instead."[100] EPA lists a number of surrogates that can be used for this purpose, including Q/d, wind trajectories, and daily light extinctions budgets and states that states can use "other reasonable techniques."[101] However, although more strongly worded in its Draft Guidance,[102] EPA does state in its Final Guidance, "[s]urrogate metric here refers to a quantitative metric that is correlated to some degree with visibility impacts as they would be estimated via air quality modeling."[103] Consequently, although EPA tells states that modeling is unnecessary and that surrogate measures can be used, modeling is required in order to check the validity of visibility surrogates. EPA should reconsider this provision, and clarify that modeling is needed to assess the collective visibility impacts of sources or source categories to establish RPGs.

## IX. Progress, degradation, and URP glidepath checks

### A. If a state's RPG is above the URP, the state's "robust demonstration" must include a consideration of specific items identified by EPA.

In section II.B.7.c of the Final Guidance, EPA discusses what could constitute a "robust demonstration," required under section 51.308(f)(3)(ii)(A) when a state's RPG is above the URP.[104] EPA states that a simple "narrative explanation of how the state has already conducted the source selection and control measures analyses in such a manner that addresses the requirements of 51.308(f)(3)(ii)" may suffice.[105] EPA then goes on to note that such a state *may* consider a long list of additional items, including reconsideration of its visibility threshold, acceptable cost threshold, additional technically feasible controls, how its determination criteria compares to that of other states, etc.[106]

In contrast, EPA's Draft Guidance did not state that a simple narrative would suffice. The Draft Guidance stated that such a demonstration *should* include consideration of a similar listing

[100] Final Guidance at 12.
[101] *Id.* at 13.
[102] Draft Guidance at 76 ("Before relying on Q/d as a surrogate for screening purposes, a state should investigate how well Q/d relates to visibility impacts for the 20 percent most impaired and 20 percent clearest days, in terms of both the central tendency of the relationship (e.g., the regression line) and the variability of the relationship (e.g., the error of the regression). This understanding should be developed through relevant modeling of some actual cases or model plant scenarios, or another appropriate approach.")
[103] Final Guidance at 10 n.25.
[104] *Id.* at 50.
[105] *Id.*
[106] *Id.* at 50-51.

of items. EPA's pivot from *should* consider to *may* consider substantially misinterprets and is directly at odds with what the robust demonstration required under section 51.308(f)(3)(ii)(A) should contain.

Moreover, states should not rely on EPA's Updated 2028 Modeling[107] to determine which Class I areas are projected to be at or below the URP. Projected conditions for 2028 are tied to the 2064 natural conditions endpoint adjustments to account for international anthropogenic contributions, as well as wildfires. By EPA's own admission as discussed *supra* section V.A, these adjustments lack scientific validation and should not be relied on to determine whether a Class I area is on track to meet its URP in 2028.[108] The result of the updated modeling adjustments reduced the number of Interagency Monitoring of Protected Visual Environments ("IMPROVE") sites projected to be above the glidepath from forty-seven to eight. IMPROVE monitors are not the same as Class I areas, however many Class I areas share monitors; only ninety-nine monitoring sites (representing 142 Class I areas) were evaluated.[109] EPA must reconsider and revise the Final Guidance to specify what a "robust demonstration" under section 51.308(f)(3)(ii)(A) requires and that a state's demonstration should include consideration of the specific list of items identified by the agency.

## X. Additional requirements for regional haze SIPs

### A. States must submit to EPA the emission inventory used in a regional haze SIP.

In section II.B.8.c of the Final Guidance, regarding section 51.308(f)(6)(v) which covers the requirements for the state's emissions inventory, EPA states that "[t]he emission inventories themselves are not required SIP elements and so are not required to be submitted according [sic] the procedures for SIP revisions. The emission inventories themselves are not subject to EPA review."[110] This conflicts with the Regional Haze Rule, is internally inconsistent with the rule and other state requirements, and is impracticable. First, EPA's statement conflicts with several sections of the Regional Haze Rule. For instance, section 51.308(f)(2)(iii) requires that the state must document the following:

> [T]he 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 Federal area it affects. . . . The emissions information must include, but need not be limited to, information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to

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[107] *See* Updated 2028 Modeling.
[108] *Id.* at 67.
[109] *Id.* at 3 n.6.
[110] Final Guidance at 55.

> the Administrator in compliance with the triennial reporting requirements of subpart A of this part.

Here, it is clear that a state is required to document the technical basis of all aspects of its regional haze demonstration. A state's emission inventory is a foundational aspect of its technical demonstration. In fact, EPA specifically calls out "emissions information," and clarifies that the emissions information must include "information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to the Administrator."[111]

Plainly, a state is required to submit the emission inventory it is using as part of its technical demonstration to EPA, and that inventory must include certain specified elements. Because states are already required to submit specified emission inventories to EPA as part of other requirements ("Part A"), EPA clarifies that a state may refer to that submission instead of physically including it in its SIP. However, the mere fact that EPA specifies a state may use an already prepared work product does not shield it from a review of its suitability for the task at hand. [112] For instance, EPA has frequently stated that states may use the technical work of RPOs in their SIPs. That position has never been interpreted to mean information is shielded from EPA review.[113] Indeed, EPA has a duty to review that inventory in the context of the state's regional haze SIP submission.[114] Thus, a state's emission inventory is an inseverable part of its regional haze SIP and subject to EPA's review.

Despite this, EPA appears to imply in its guidance that it cannot bring to the state's attention potential faults in the emission inventory a state used to support its regional haze SIP, nor even examine that inventory in the context of its review of the state's regional haze SIP. EPA should revise the Final Guidance to advise states that a state's emission inventory is a part of the state's SIP and subject to EPA's review.

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[111] *Id.*

[112] *See* EPA's "Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations," EPA-454/B-17-002, at 11 (May 2017), ("[Inventory information provided to EPA] will allow the EPA to make a determination whether the emissions information used in Regional Haze analysis is sufficient for the purposes of the SIP.")

[113] For instance, in the Texas FIP, EPA observed that under the current regulation each state "must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving *reasonable progress* in each mandatory Class I Federal area it affects." 79 Fed. Reg. 74,818, 74,829 (Dec. 16, 2014) (emphasis in original). While the current regulations provide that, "[s]tates may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants," 40 C.F.R. § 51.308(d)(3)(iii), the Texas haze rule clarified that in situations "where a regional planning organization's analyses are limited, incomplete *or do not adequately assess the four factors*, however, then states must fill in any remaining gaps to meet this requirement." *Id.* (emphasis added).

[114] In the 2017 Regional Haze Rule revision, EPA makes it a point to review a number of circuit court opinions that affirm EPA's review authority, including the Eight Circuit's conclusion that EPA "must 'review the substantive content of the . . . determination." 82 Fed. Reg. at 3090 (quoting *Ariz. el rel. Darwin v. EPA*, 815 F.3d 519, 531 (9th Cir. 2016).

B. States must ensure that FLM opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP.

In Section II.B.8.a of the Final Guidance, EPA provides guidance to the states regarding the FLM consultation requirements in the Regional Haze Rule, 40 C.F.R. § 51.308. Although EPA reiterates that states are required to consult with FLMs, EPA should reconsider and revise the Final Guidance to ensure that states give credence to the opinions and concerns expressed by FLMs. FLMs have affirmative duties under section 169A(a) and (d) of the Clean Air Act as well as mandates to protect and manage public lands under the Wilderness Act[115] and the Organics Act[116]. Therefore, EPA should revise the Final Guidance to direct states that to work collaboratively with FLM to develop regional haze SIPs that satisfy federal agency duties and public resource protections.

XI. Overarching recommendations

A. EPA should emphasize that the end result must be reasonable progress.

EPA should make clear in a revised Final Guidance that the end result of any state's implementation plan must be real, reasonable progress. Consequently, each new plan must require that states actually reduce their emissions that contribute to visibility impairment. The statute requires each haze plan to contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress . . . ."[117] Therefore, any interpretation of the Regional Haze Rule via guidance should direct a state's long-term strategy to be more than just a hand waving exercise—each plan must require adequate emission limits and other enforceable measures to make reasonable progress.[118] EPA should revise the Final Guidance to explicitly provide that actually requiring emission reductions which constitute reasonable progress must be the outcome of the four-factor analysis to meet the applicable requirements; deliberation, no matter how well documented, is not enough. Emission reductions recognized through the four-factor analysis must result in emission reduction measures enforceable through a state or federal regional haze plan.

B. Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.

EPA must also revise the Final Guidance to clarify that decisions on which controls to require as part of long-term strategy cannot rest solely on controls required by past SIPs and state rules. Although EPA stated in the Draft Guidance that decisions on whether controls for a source or source category are cost-effective or provide sufficient visibility improvement cannot rely solely on past decisions evaluating controls for similar sources[119], that language is completely absent from the Final Guidance. EPA must revise the Final Guidance to state this point. For

[115] 16 U.S.C. §§ 1131-1136.
[116] 54 U.S.C. § 100101.
[117] 42 U.S.C. § 7491(b)(2).
[118] *See id.*
[119] Draft Guidance at 97, 103.

example, costs or technologies which were previously considered unreasonable or infeasible at a later date may become more common and may nevertheless be necessary in the second or future planning periods to make reasonable progress. Likewise, making reasonable progress in the current and future planning periods will require the implementation of controls that individually account for smaller visibility impacts than those contemplated in the first planning period and in other past emission reducing rules and permits. Therefore, EPA must revise the Final Guidance to direct states to conduct new source-specific, four-factor emission reduction analyses.

C. EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.

The Clean Air Act not only requires that existing visibility impairment be remedied, but that future impairment be prevented. 42 U.S.C. § 7491(a)(1). As such, it is imperative that each state's long-term strategy be required to include measures to prevent regional haze visibility impairment and that such plans take into account the effect of new sources, as well as existing sources of visibility impairment. EPA must revise its Guidance to comport with this requirement.

EPA has historically relied on the prevention of significant deterioration ("PSD") permitting program and the visibility new source review ("NSR") requirements mandated by 40 C.F.R. § 51.307[120] to address this requirement of the national visibility goal.[121] These provisions essentially mandate that new and modified major sources that are subject to major source permitting requirements do not adversely impact visibility in any Class I area. However, much has changed in the PSD and NSR permitting programs since 1980. The current PSD rules, as well as the major source nonattainment NSR rules, now exempt many modifications at existing major sources that were previously subject to PSD review. As a result, the PSD and visibility NSR rules do not provide as comprehensive Class I areas protections as they previously did, due to impacts from modified sources. Further, there have been significant increases in emissions near some Class I areas due to oil and gas emissions and other activities that are not adequately addressed by the PSD permitting program.

EPA must revise its Final Guidance to ensure that states prevent future impairment by analyzing new and modified emission sources and by requiring mitigation of the cumulative visibility-impairing emissions. As we discuss below, it is especially important for EPA to articulate that states consider minor, area, and other new growth, or modification of stationary sources that are not subject to the Class I area protections of the PSD permitting and visibility NSR requirements.

[120] 40 C.F.R. §51.307(b)(2) and (c) provides that the PSD requirements of 40 C.F.R. §51.166(o), (p)(1) through (2), and (q) apply to new and modified major proposing to locate in nonattainment areas that may have an impact on visibility in a mandatory Class I area.
[121] *See* 45 Fed. Reg. 80,089 (Dec. 2, 1980).

1. The 2002 PSD and nonattainment NSR Rule revisions exempt many modifications from PSD permitting that could result in large, visibility-impairing emission increases from existing major sources.

EPA has historically relied on the PSD and nonattainment/visibility NSR permitting programs to meet the requirement of preventing future impairment of visibility. The PSD permitting requirements specifically provide for ensuring that a new or modified major source will not adversely impact visibility in a Class I area[122], and the EPA's visibility NSR rules in 40 C.F.R. §51.307(c) require new and modified major sources proposing to locate in nonattainment areas that may impact visibility in a Class I area to meet these same requirements of the PSD program.[123] However, the December 2002 revisions to the PSD and nonattainment NSR permitting requirements significantly reduced the scope of modifications that would trigger PSD or nonattainment NSR as major modifications by drastically changing the methodology for determining whether a significant emission increase would occur as a result of a modification.[124]

Despite these significant regulatory changes which reduced the scope of modified sources subject to PSD and nonattainment NSR permitting, EPA has never re-evaluated its reliance on the major source permitting programs as sufficient to prevent future impairment of visibility. However, these rules, as revised in recent years, will likely allow significant increases[125] in actual emissions from existing sources to occur without any evaluation of the impacts on visibility and without even applying BACT or LAER, due to being exempt from PSD or nonattainment NSR permitting.

In summary, the PSD and nonattainment NSR rules as revised in 1992 and 2002 now exempt many modifications that would have previously been subject to major source permitting, including the visibility requirements of the PSD program and visibility NSR rules. Thus, while the rules still include vital provisions for the prevention of future visibility impairment, the PSD and visibility NSR rules are no longer adequate by themselves to ensure the prevention of future visibility impairment. In light of this, EPA should revise the Final Guidance to clarify that states may not solely rely on the PSD and visibility NSR programs to prevent future impairment of visibility. EPA must ensure that states specify requirements in their SIPs to prevent future visibility impairment from the new source growth in any state that may increase visibility-impairing pollution and thus affect Class I area visibility.

2. Minor, area, mobile, and other source emissions must be evaluated to prevent future, as well as remedy existing, impairment of visibility.

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[122] 40 C.F.R. §52.21(o), (p)(1) and (2), and (q).
[123] 40 C.F.R. §51.307(b)(2) and (c).
[124] 67 Fed. Reg. 80,185, 80,186-89 (Dec 31, 2002) (also known as "NSR Reform" Rule).
[125] *See* Joseph Goffman, et al., EPA's Attack on New Source Review and Other Air Quality Protection Tools (Nov. 1, 2019), http://eelp.law.harvard.edu/wp-content/uploads/NSR-paper-EELP.pdf.

Although the Final Guidance mentions minor, area, mobile, and other emission sources, most of the discussion addresses major stationary sources. EPA should be more explicit in its expectation that states evaluate sources and source categories that are not major stationary sources as well, including the potential for growth in emissions from these sources. For example, given the increases in emissions from oil and gas development over the last 10 years,[126] it is clear that the existing SIPs and FIPs do not currently include adequate mechanisms for preventing visibility impairment from these sources as production ebbs and flows with economic conditions and other factors, such as deregulation and technology. EPA must revise the Final Guidance to clarify that states need to address these sources in the aggregate, rather than source-by-source.

There are several examples of rules and programs that may be necessary in a long-term strategy to prevent future impairment of visibility in Class I areas. EPA should revise the Final Guidance to direct states to consider these examples and include them where appropriate in SIPs.

a. Methods to address visibility-impairing emissions from oil and gas development

EPA should revise the Final Guidance to explicitly note that it expects states to review area sources like oil and gas, and should provide additional guidance on how to do so. Undoubtedly, this should begin with requiring states to collect better data on the emissions from oil and gas.

In many states, emissions from oil and gas development are a significant threat to visibility and air quality in Class I areas. Such development often occurs on federal lands that are near to or abut Class I areas For example, oil and gas development contributes to visibility impairment in public lands in Utah and Colorado where the NPS found that oil and gas development and leasing in the two states would "cause visibility impairment" at Dinosaur National Monument.[127] Additionally, NPS recently found impacts from oil and gas emissions at Carlsbad Caverns and San Pedro Parks Wilderness Class I areas, among others, based on 2008 emissions inventories—which do not capture more recent growth—and include only a portion of emissions from the production process.[128] Examples of Class I areas currently or potentially

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[126] "The U.S. Energy Information Administration ("EIA") reports that oil production growth in the United States has risen by about 3 million barrels per day (from 5.8 to 8.72 MMb/d) from January 2001 to July 2014 (EIA, 2014a). Natural gas production has increased from 53.74 to 70.46 billion cubic feet per day within this time period (EIA, 2014a). The trend is expected to continue with the number of oil and gas wells in the lower 48 states projected to increase by 84 percent between 2013 and 2040 (EIA, 2014b)." Thompson et al., Modeling to Evaluate Contribution of Oil and Gas Emissions to Air Pollution, 67 Journal of the Air & Waste Management Association Vol. 4, 445 (Sept. 2016), https://doi.org/10.1080/10962247.2016.1251508.

[127] Memorandum from Regional Director, Intermountain Region, National Park Service, to Planning and Environmental Coordinator, BLM 9 (2013); *see also* Memorandum from Superintendent, Dinosaur National Monument, National Park Service, to Field Office Manager, BLM Vernal Field Office 2 (Aug. 2017); Krish Vijayaraghavan et al., Ramboll Environ US Corporation, 2017); BLM, Colorado Air Resources Management Modeling Study (CARMMS): 2025 CAMx Modeling Results for the High, Low and Medium Oil and Gas Development Scenarios, 104-05 (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.

[128] Thompson et al., *supra* note 126, at 456; *see also* Table C6, *available at* https://www.tandfonline.com/doi/suppl/10.1080/10962247.2016.1251508?scroll=top.

impacted by oil and gas emissions include: Theodore Roosevelt and Lostwoods (Bakken Shale in eastern Montana and North Dakota); Wind Cave and Badlands (Powder River Basin in northeast Wyoming); Bridger and Fitzpatrick Wilderness Areas (Pinedale Anticline and Jonah Fields in western Wyoming); Mesa Verde (North and South San Juan Basin); Carlsbad Caverns and Guadalupe Mountains (Permian Basin in southeastern New Mexico and western Texas); and Canyonlands and Arches (Uintah, Paradox, and Piceance Basins in Utah and Colorado).

Significant information is available to enable states and EPA to develop strategies to reduce visibility-impairing emissions from this significant source category. However, these prior analyses do not substitute for meaningful consideration of oil and gas emissions reductions sufficient to meet the Regional Haze Rule's "reasonable progress" mandate. NPCA's recent report, "Oil and Gas Sector Reasonable Progress Four-Factor Analysis for Five Source Categories" assesses emissions controls for the five primary sources of visibility-impairing (and health harming) pollution in the sector: gas-fired reciprocating internal combustion engines ("RICE"); diesel-fired RICE; gas-fired combustion turbines; gas-fired heater, boilers, and reboilers; and flaring and thermal incineration of excess gas and waste gas.[129] The controls and practices included in this document represent various requirements for sources across the country and should be considered by states with emissions from the oil and gas sector.

Resource Management Plans ("RMPs") or land use plans issued by federal agencies explain how the agency will manage areas of public land over a period of time, usually ten to fifteen years. RMPs and amendments to those plans are required to go through a public review process under the National Environmental Policy Act ("NEPA"), which must include an analysis of projected impacts to all resources, including air quality. Such plans would include projections of oil and gas development, among other land use projections, on federal lands. Unfortunately, numerous RMPs have not been revised for decades, and only a few consider the effect of emissions from the planning area. EPA should revise the Final Guidance to require that states consider RMPs and other land use plans in determining the appropriate measures to prevent future impairment of visibility to include in regional haze SIPs. However, if RMPs are outdated or fail to consider the effects of visibility-impairing pollution from development, EPA must also indicate that those RMPs not be relied upon.

Recent NEPA analyses conducted for projected oil and gas development in RMPs can be useful tools for obtaining data regarding anticipated growth in such emissions. However, neither NEPA assessments nor RMPs are tools for preventing future impairment from oil and gas development. First, if adverse impacts are projected, the federal agency may make recommendations on mitigation methods to avoid adverse impacts, but neither the federal agency nor the local or state air permitting agency are under any obligation to implement such mitigation measures. Second, the federal agency is often making projections of expected amounts of development and in the types and emission rates of emissions units utilized. Those projections do

[129] Vicki Stamper & Megan Williams, Nat'l Parks Conservation Ass'n, Oil and Gas Sector Reasonable Progress Four-Factor Analysis for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration (Mar. 6, 2020) ("NPCA Report").

not always reflect the level of development that actually occurs, or the specific emission units and emission rates that are utilized. The Colorado Air Resources Management Modeling Study is one example of the type of information which can be developed in conjunction with the RMP process.[130]

In developing long-term strategies, EPA should direct states to use available information such as county-level reported emissions data and RMP and site-specific NEPA analyses, and request additional information to round out and make inventories accurate. To aid in this data gathering, EPA should direct industry to produce emissions inventories and submit them to states alongside an evaluation of emissions-reduction strategies and control technologies for this significant source of visibility impairment. Further, EPA should revise the Final Guidance to explicitly advise states on creating and making publicly available oil and gas emissions data.

States with significant oil and/or gas development should be required to consider the adoption of emission control regulations for the oil and gas development industry to reduce visibility-impairing emissions from such development.[131] Many states already require measures to reduce emissions from the sector. For example, California has enacted extensive air pollution requirements for oil and gas production, processing, and storage.[132] Colorado has also adopted emission requirements for the oil and gas industry.[133] Pennsylvania has also revised the state's oil and gas drilling regulations.[134] While these regulations may not be sufficient as to visibility impairment from the sector's emissions, the regulations provide relevant examples of states' decisions to address threats to air quality that are not covered by federal major source permitting requirements. EPA should identify the source types and associated emission-reducing measures available in the sector and use them to develop guidance to specify EPA's expectations of states in assessing these sources and requiring emission reduction measures from them. EPA must reconsider and revise the Final Guidance to require states to apply these and other control measures in their regional haze SIPs.

b. Minor New Source Review permitting programs

A state's minor NSR permitting program can be a useful tool to impose emission limitations and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal. EPA should revise the Final Guidance to direct states to model new or modified minor NSR sources for their impacts on visibility in Class I areas. States could thus determine if the source's emissions would be consistent with making reasonable progress towards the national visibility goal, similar to the requirement in 40 C.F.R. §51.307(c) of the visibility NSR rules. Such a provision would also be

[130] *See* BLM, Colorado Air Resources Management Modeling Study (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.
[131] NPCA Report at 7-10.
[132] California Air Resources Board, Oil & Natural Gas Production (last reviewed July 18, 2017), https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm.
[133] Colo. Regulation No. 7, Section XII, https://www.colorado.gov/pacific/cdphe/air/oil-and-gas-compliance.
[134] *See* Environmental Protection Performance Standards at Oil and Gas Well Sites, 46 Pa. B. 6431 (Oct. 8, 2016), http://www.pacodeandbulletin.gov/Display/pabull?file=/secure/pabulletin/data/vol46/46-41/1757.html.

consistent with section 7410(a)(2)(D)(i)(II) of the Clean Air Act, which requires SIPs to include adequate provisions prohibiting any source type from emitting any air pollutant which will interfere with measures to protect visibility. States could include criteria to ensure that the sources most likely to interfere with making reasonable progress are addressed, based on total emissions of visibility-impairing pollutants, distance to Class I areas, and/or other criteria focused on modifications at existing major sources that avoid PSD or nonattainment NSR review. EPA should instruct states to add such provisions to their minor NSR programs as necessary to ensure that their long-term strategies adequately prevent future impairment to visibility. Such provisions should also be incorporated and made enforceable through regional haze SIPs relying on such emission reductions to make reasonable progress.

States that decide to rely on minor NSR programs to prevent future impairment should be required to examine the relevant definitions and exemptions that exist in their programs to ensure that the types of sources that need to be addressed to prevent future impairment are indeed subject to the states' minor NSR programs. A state's minor NSR program also may need to be revised to include emissions from emitting units not typically covered under PSD permitting requirements, such as fugitive emissions.

Applicability at minor NSR sources should be based on projected changes in allowable or actual emissions from a baseline reflective of recent emissions. If a state is intending to rely on its minor NSR program to prevent future impairment of visibility, then the minor NSR program must be written in a manner to truly accomplish that intention. As other Clean Air Act programs fail to adequately integrate limits for new or modified sources, regional haze SIPs should be used directly for this purpose.

c. Provisions for other potential threats to visibility impairment

There are a number of source types other than those covered by a minor NSR permit program or oil and gas development that could potentially impair visibility. In recognition of this, EPA should revise its Final Guidance to recommend that states specifically include the analyses of these potential sources in their long-term strategies, and if necessary, adopt provisions to address them. For instance, if construction activities threaten future impairment, states should adopt control measures to mitigate air pollution at construction sites. As an example, the Sacramento Metropolitan Air Quality Management District applies air emissions requirements to construction sites.[135] California also has stricter mobile source emissions requirements (including for non-road engines) that apply under federal rules, and states with significant mobile source growth threatening future impairment could consider adopting such standards as their own.[136] EPA should encourage states to consider various measures to address

[135] *See* Sacramento Metro. Air Quality Management Dist., CEQA Guide, Ch. 3: Construction-Generated Criteria Air Pollutant and Precursor Emissions (April 2019), http://www.airquality.org/LandUseTransportation/Documents/Ch3ConstructionFinal4-2019.pdf.

[136] Congress preempted states from setting emission standards for mobile sources, except that California could set its own standards with EPA's permission and other states could opt into the stricter California standards (generally for ozone SIP purposes). 42 U.S.C. § 7543(e)(2)(B)(i)-(ii).

potential future Class I visibility impairment, based on the recent or planned growth in new source emissions expected for the state, that could threaten future impairment of visibility in any Class I area.

Additionally, to the extent that states have limited information on such sources, EPA should require that states collect and submit actual emissions increase data on minor modifications at existing sources in order to gather more information on the extent of minor source growth and on new minor, area, and other source growth.

Visibility-impairing emissions need to be inventoried and modeled from many sectors in order to properly inform the next round of haze plans. Several states have started collecting and submitting oil and gas emissions data to be inventoried and modeled for purposes of regional haze. For instance, the Western Regional Air Partnership has started collecting from its oil and gas producing states emissions for their modeling inventory.[137] However, there are several states not in the western region of the country, such as Pennsylvania and Virginia, which are significant producers of oil and gas, and should also be collecting and submitting oil and gas emissions data.[138] Furthermore, as noted *supra* section III.H, there is no inventory of emissions from the agricultural sector; states should develop such inventories and submit them with their regional haze SIPs.

Emissions data from wood burning devices should be modeled. As EPA has explained, the smoke from these devices "contains harmful particle pollution, also known as fine particulate matter or PM2.5, along with other pollutants including carbon monoxide, volatile organic compounds (VOCs), black carbon, and air toxics such as benzene."[139] EPA has also confirmed that residential wood combustion "accounts for 44 percent of total stationary and mobile polycyclic organic matter (POM) emissions, nearly 25 percent of all area source air toxic cancer risks and 15 percent of noncancer respiratory effects."[140] Furthermore, wood burning devices are a significant source of heating for many communities near Class I areas that struggle with regional haze pollution problems. Wood burning devices materially contribute to the significant proportion of particulate matter (fine and course) and VOC emissions that come from residential wood combustion in Arizona, Massachusetts, Minnesota, Nevada, Washington and other states, adding to regional haze visibility problems in Class I areas around the country.

While the collection and evaluation of much of this data should inform the next round of haze plans, we note that for the oil and gas sector, this data is sufficiently available such that regulation of the sector is appropriate and much needed in this second round of regional haze

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[137] *See* Western Regional Air Partnership ("WRAP"), EGU Emissions Analysis Project, https://www.wrapair2.org/EGU.aspx.

[138] *See* U.S. Energy Info. Admin., Pennsylvania State Profile and Energy Estimates (last updated Aug. 15, 2019), https://www.eia.gov/state/?sid=PA; U.S. Energy Info. Admin., Virginia State Profile and Energy Estimates (last updated Sept. 15, 2019), https://www.eia.gov/state/?sid=VA.

[139] EPA, Fact Sheet: Overview of Final Updates to Air Emissions Requirements for New Residential Wood Heaters, at 1 (Feb 4, 2015), https://www.epa.gov/sites/production/files/2015-02/documents/20150204fs-overview.pdf.

[140] EPA, Strategies for Reducing Residential Wood Smoke, Publ'n No. EPA-456/B-13-001 at 4 (Mar. 2013), https://www.epa.gov/sites/production/files/documents/strategies.pdf.

planning. EPA should specify that in order for a state to satisfy the requirements of proposed 40 C.F.R. § 51.308(f), states must consider the cumulative impacts from minor and other source growth that may affect future visibility impairment. With this information, states can determine the number and types of new source growth and magnitude of emissions that may threaten future visibility impairment, which can then assist states in developing targeted measures to prevent future visibility impairment and address regional haze from these source types. Such measures should be required to be part of the long-term strategy of the regional haze SIP.

In summary, EPA must revise the Final Guidance to require long-term strategies to include measures to ensure the prevention of future visibility impairment, as well as the remedying of existing visibility impairment in Class I areas, in accordance with the national visibility goal of the Clean Air Act. While the PSD and visibility NSR programs have some effective provisions for ensuring that new and modified sources subject to those permitting requirements do not threaten future visibility impairment, those programs are not sufficient to fully address the statutory requirement of preventing future impairment to visibility. EPA should require states to evaluate the threats to future impairment to visibility in any Class I area and to adopt provisions within regional haze SIPs to minimize emissions from such sources, and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal.

## XII. Conclusion

The Conservation Organizations respectfully ask that EPA reconsider and revise the Final Guidance as mentioned above.

Sincerely,

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**POLLUTION CONTROL HEARINGS BOARD**
**STATE OF WASHINGTON**

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| NATIONAL PARKS CONSERVATION ASSOCIATION,<br><br>Appellant,<br><br>v.<br><br>STATE OF WASHINGTON, DEPARTMENT OF ECOLOGY; and BP WEST COAST PRODUCTS, LLC,<br><br>Respondents. | PCHB No. 10-162<br><br>DEPARTMENT OF ECOLOGY'S PREHEARING BRIEF |

## I. INTRODUCTION

The National Parks Conservation Association (NPCA), challenges the Department of Ecology's issuance of Permit PSD No. 16-01 (Permit) authorizing BP West Coast Products LLC (BP) to replace two coker heaters at its refinery in Cherry Point, Washington (Coker Heater Project). The evidence and testimony presented to the Pollution Control Hearings Board will show that Ecology appropriately followed federal guidance in determining the impacts of the Coker Heater Project on air quality related values (AQRVs). The evidence will also show that Ecology exercised appropriate professional engineering judgment and imposed appropriate Permit requirements for best available control technology (BACT) to control emissions of nitrogen oxides ($NO_x$) and sulfur dioxide ($SO_2$) from the new coker heaters.



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Finally, Ecology will explain how the information provided in BP's permit application shows that the sulfur content of coker off-gas will not increase as a result of the Coker Heater Project.

Ecology will present two witnesses, Air Quality Engineer Alan Newman, and Air Quality Engineer Gary Huitsing. Mr. Newman has been working with Ecology on air permitting issues since 1975 and became a part of the Air Quality Program in 1992. Mr. Newman will testify concerning Ecology's historical permitting practices and Ecology's long-time understanding of federal guidance. Mr. Newman is also Ecology's lead for the federal Regional Haze Program, and will testify concerning how that program interacts with the PSD program. Mr. Huitsing was the permitting engineer on the BP Permit. Mr. Huitsing will testify concerning specific questions related to that permit.

## II. BACKGROUND FACTS

BP West Coast Products, LLC (BP) operates an oil refinery in Blaine, Washington that produces petroleum based fuels. This case concerns a permit that will allow BP to replace the two coker heaters at the facility, install a lean oil absorption system with a compressor in the coker off-gas system, revise the main fractionator over head accumulator that separates water from hydrocarbon vapor, and to install new isolation valves on ten existing heat exchangers and to install new bypasses on four existing heat exchangers.

On March 27, 2014, Ecology met with federal land managers and BP at a pre-application meeting to discuss BP's plan to submit a permit application for the new project. As required by Ecology rules, BP also sent the permit application to federal land managers. WAC 173-400-117(3)(b). Ecology determined the application was incomplete on October 22, 2014. BP submitted a revised application to Ecology and the federal land managers in March 2016, with supplementary materials after that date. The application was determined to be complete on April 28, 2016. BP provided a consolidated application (including supplementary materials) on June 23, 2016 and provided further supplemental information on November 4, 2016.



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The Coker Heater Project is a major modification of the BP Cherry Point refinery, which is a major source of air contaminants. The BP Cherry Point facility is located in an area that is in attainment of all the national ambient air quality standards (NAAQS). A major modification of a major source in an attainment area must obtain a permit under EPA's prevention of significant deterioration (PSD) program. 42 U.S.C. § 7475(a)(1); 40 C.F.R. § 52.21(a)(2). Therefore, BP's Coker Heater Project required a PSD permit.

Ecology issues all PSD permits in Washington except those issued for facilities in Indian Country and those issued by the Energy Facility Site Evaluation Council (EFSEC). Therefore, even though the BP Cherry Point facility is located within the territory normally regulated by the Northwest Clean Air Agency, Ecology issued the PSD permit for this project. Ecology's PSD program has been approved by EPA. Ecology has adopted by reference most of EPA's regulations governing PSD permitting (found at 40 C.F.R. § 52.21). WAC 173-400-720(4)(a)(vi). For ease of reference, this brief will cite to the relevant federal regulation rather than the Ecology regulation adopting the federal regulation by reference. The final permit was issued May 23, 2017. Permit at 1. On June 21, 2017, the National Parks Conservation Association (NPCA) timely appealed the permit. NPCA is a non-profit organization. NPCA is not the National Park Service, is not formally affiliated with the National Park Service, and does not represent the National Park Service.

## III. LEGAL ISSUES AND BURDEN OF PROOF

### A. Legal Issues

The Board has indicated that, after summary judgment, the Board is interested in hearing evidence on five issues in this case. The issue numbers given below are the issue numbers identified in the Board's Prehearing Order. Ecology will provide testimony and evidence on Issues No. 1, 5, 6, and 7.

1. Will BP's Coker Heater Replacement Project have an adverse impact on AQRVs at national parks?



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5. Should Ecology have required selective catalytic reduction as best available control technology for nitrogen oxides ($NO_x$)?

6. Should Ecology have required the use of a lean oil system with a compressor as best available control technology for sulfur dioxide ($SO_2$)?

7. Should Ecology have required best available control technology for $SO_2$ for emission units throughout the BP refinery as a result of the increased use of coker off-gas resulting from the project?

9. Whether the Board has jurisdiction to review issues that are based on alleged infirmities associated with the current EPA approved State Implementation Plan provisions for Washington State?

**B. Burden of Proof**

In an appeal of an air permit, the appellant has the burden of proof. WAC 371-08-485(3); *Sierra Club v. Sw. Wash. Clean Air Agency*, PCHB No. 09-108, Order Granting Summary Judgment at 10 (Apr. 19, 2010). Thus, NPCA has the burden of proving that Ecology's decisions regarding Permit No. PSD 16-01 do not conform to the law.

## IV. SUMMARY OF ECOLOGY'S CASE

In its summary judgment order (SJ Decision) in this case, the Board recognized "[t]he federal agencies are not parties to this case and there is no direct evidence in the Board record on their current position." SJ Decision at 11 n.3. The Board also recognized that the "NPCA is not the Park Service, and has not been authorized to represent the Park Service in this proceeding. . . . Also, there is no evidence that NPCA represents EPA or the Department of the Interior. Therefore, NPCA does not have standing to represent the interests of any of these federal agencies." SJ Decision at 21. Therefore, the Board found there was no need to address the question of deference to either EPA or the National Park Service. See SJ Decision at 11 n.3.

**A. Issue No. 1: AQRV analysis**

Ecology engineer Alan Newman will testify concerning his experience with analyses of AQRVs, both in permitting and in relation to the federal Regional Haze Program. Mr. Newman will discuss his understanding of the Federal Land Managers' Air Quality Related Values Work Group (FLAG) 2010 guidance and his interpretation of the method that the guidance



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recommends for determining the net emission increases that need to be modeled for a visibility analysis and for a deposition analysis. Mr. Huitsing will testify about his review of the AQRV analyses provided by BP and the National Park Service for the Coker Heater Project, and the concerns that led him to ask BP to redo its analysis. He will also discuss the Q/D process described in the FLAG guidance and why it is relevant to BP's PSD permit. He will discuss the method for determining the net emissions increase due to a project that is used in a Q/D evaluation. Finally, he will describe what the Q/D analysis shows about the BP project's impacts on the National Parks.

Mr. Newman will present testimony concerning the federal Regional Haze program and how it interacts with PSD permitting requirements. Mr. Newman will testify that the National Park Service's finding of adverse impacts from the BP project in this case is an integral part of the Regional Haze Program, and will be included as a component of the next analysis of the state's progress toward better visibility required by the Regional Haze Program. Both Mr. Newman and Mr. Huitsing will testify and provide evidence that the National Park Service has recognized that the proper avenue for addressing the concerns identified in its adverse impacts determination is the Regional Haze Program and not the PSD permitting process for the Coker Heater Project.

**B. Issue No. 5: NOx BACT**

In accordance with the Board's ruling on summary judgment, Mr. Newman and Mr. Huitsing will testify concerning EPA guidance on how to evaluate the use of a particular control technology at other facilities and the factors Ecology considered in making its cost-effectiveness determination on selective catalytic reduction (SCR). Ecology testimony and evidence will clarify that EPA guidance provides different levels of scrutiny for a control technology applied at other facilities depending on whether or not that technology has been required as BACT. If the technology has been required as BACT for similar emission units at other facilities, the permitting authority must provide evidence that costs would be



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disproportionately high at the current facility before rejecting the control technology as BACT. By contrast, if the technology has not previously been required as BACT for similar emission units at other facilities, or has rarely been required as BACT, but has been used at other facilities for other reasons (e.g., to avoid PSD, as part of a settlement), EPA guidance specifies that the permitting authority must show that the costs of applying the technology as BACT for this project are higher than the costs of BACT at other facilities for the same pollutant.

Mr. Huitsing will explain how he evaluated the information BP submitted concerning the use of SCR to control $NO_x$ emissions from coker heaters at other refineries. He will also testify concerning the costs of BACT for $NO_x$ for the BP Coker Heater Project, and the costs of BACT for $NO_x$ at other facilities in Washington. Mr. Newman will address Ecology's historical BACT cost thresholds and how these cost thresholds have evolved over time to the current level. Finally, Mr. Newman will testify concerning EPA's recommendation that a seven percent interest rate be used for BACT cost analyses. Mr. Huitsing will testify that EPA's latest guidance, which changes that approach, became effective in November 2017, well after the BP Permit for the Coker Heater Project had been issued.

### C. Issue No. 6: $SO_2$ BACT

Mr. Huitsing will discuss why he did not include the compressor as part of the lean oil absorption system required as BACT. He will testify concerning his conclusion that the use of a compressor with the lean oil absorption system is not cost effective, and therefore cannot be required as BACT. He will also testify that it is his understanding that BP's proposed use of the compressor in connection with the lean oil adsorption system is a new and unproven concept, and that it would therefore not be appropriate to set a BACT emission limit reflecting its use. Finally, he will testify that it is his understanding that the compressor is being used to help BP recover useful product.

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### D. Issue No. 7: The Amount of Sulfur in Coker Off-gas

Mr. Huitsing will testify that the information provided in BP's permit application shows that the amount of sulfur in the off-gas from BP's new coker heaters will not be higher than the amount of sulfur in the off-gas from BP's current coker heaters. He will point out that according to BP's permit application, any annual increase in sulfur emissions from the coker heater off-gas will result from the fact that the coker heaters will be operating more days of the year because they will not be required to go offline for maintenance as often as the current coker heaters. He will also testify that, because there will be no change in the amount of sulfur in the coker off-gas, there is no basis for requiring BACT for the downstream emission units that use coker off-gas as part of their fuel mix.

## V. CONCLUSION

The evidence and testimony will demonstrate that in issuing the permit for the BP Coker Heater Project, Ecology appropriately evaluated the impacts of the project on federal Class I areas, correctly determined BACT for $NO_x$ and $SO_2$, and correctly determined that the sulfur content of the coker off-gas would not increase as a result of the project. Ecology therefore respectfully asks the Board to affirm Ecology's Permit No. PSD 16-01.

DATED this 12th day of April, 2018.

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## CERTIFICATE OF SERVICE

Pursuant to RCW 9A.72.085, I certify that on the 12th day of April 2018, I caused to be served the Department of Ecology's Prehearing Brief in the above-captioned matter upon the parties herein as indicated below:

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the foregoing being the last known address.

I certify under penalty of perjury under the laws of the state of Washington that the foregoing is true and correct.

DATED this 12th day of April 2018, in Olympia, Washington.

MEAGHAN KOHLER, Legal Assistant

POLLUTION CONTROL HEARINGS BOARD
STATE OF WASHINGTON

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| NATIONAL PARKS CONSERVATION ASSOCIATION, Appellants, | ) | |
| vs. | ) | PCHB No. 17-055 |
| STATE OF WASHINGTON, DEPARTMENT OF ECOLOGY, and BP WEST COAST PRODUCTS, LLC, Respondents. | ) | |

HEARING, VOLUME IV

April 26, 2018

Tumwater, Washington

Pages 675 through 905

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KAY BROWN
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EXAMINATION INDEX

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EXHIBIT INDEX

| EXHIBIT NO. | DESCRIPTION | ADMITTED |
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| Exhibit No. P-99 | October 23, 2016 email Re: NPS Modeling comments | 724 |
| Exhibit No. P-110 | February 9, 2017 email Re: Re capable of accommodating | 720 |
| Exhibit No. R-33 | July 25, 2001, letter from Weber to Higgins | 692 |
| Exhibit No. R-53 | April 26, 2017, comment letter from Johnson to Huitsing | 692 |
| Exhibit No. R-ECY-1 | Resume of Gary Huitsing | 829 |
| Exhibit No. R-ECY-2 | Resume of Alan Newman | 748 |
| Exhibit No. R-ECY-3 | Letter to Maureen Foster, Department of Interior, from Marc Crooks, Ecology, Dated May 23, 2017 | 869 |
| Exhibit No. R-ECY-4 | Letter to Gary Huitsing, Ecology, from the Department of Interior, dated April 26, 2017 | 871 |
| Exhibit No. R-ECY-5 | Gary Huitsing calculations regarding Q/d for emissions from the Coker Heater Project | 860 |
| Exhibit No. R-ECY-6 | BP Cherry Point Refinery Modeling Protocol, Coker Heaters Replacement Project, March 2014 | 850 |
| Exhibit No. R-ECY-7 | Email from Rick Graw, federal land manager, to Ecology, dated March 24, 2014 | 850 |
| Exhibit No. R-ECY-8 | Washington State Regional Haze 5-Year Progress Report | 756 |

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| EXHIBIT NO. | DESCRIPTION | ADMITTED |
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| Exhibit No. R-ECY-9 | Ecology list of NOx costs in recent BACT determinations | 785 |
| Exhibit No. R-ECY-10 | Louisiana Department of Environmental Quality Briefing Sheet | 876 |
| Exhibit No. R-ECY-11 | Excerpt from Meridian Energy Group, Inc. Permit Application, Exhibit C: Controls Technology Review | 879 |
| Exhibit No. R-ECY-13 | Map of nonattainment areas in Indiana showing location of BP Whiting facility | 883 |
| Exhibit No. R-ECY-14 | Supporting Calculations for Ecology and NWCAA recalculation of SCR BACT cost for NOx in Ecology Technical Support Document | 900 |
| Exhibit No. R-ECY-15 | Excerpts from EPA Air Pollution Cost Control Manual, Sixth Edition, January 2002 | 790 |
| Exhibit No. R-ECY-19 | Excerpts Chapter 2 Cost Estimation: Concepts and Methodology, U.S. Environmental Protection Agency, November 2017 | 790 |
| Exhibit No. R-ECY-20 | Excerpts of the Statement of Basis for the Air Operating Permit – Final, Shell Puget Sound Refinery, May 5, 2015 | 790 |
| Exhibit No. R-ECY-21 | EPA letter from Robert Miller, Chief, Permits and Grants Section, to Lloyd Eagan, dated February 8, 2000 | 804 |

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| EXHIBIT NO. | DESCRIPTION | ADMITTED |
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| Exhibit No. R-ECY-22 | EPA's guidance memorandum, Dated July 28, 1983, Subject: PSD Applicability Pulp and Paper Mill, To Michael M. Johnston | 804 |
| Exhibit No. R-ECY-23 | Letter from EPA Region 8 to Mr. O'Clare of North Dakota | 785 |

BE IT REMEMBERED that on Thursday, April 26, 2018, at 1111 Israel Road S.W., Tumwater, Washington, at 9:00 a.m., before KIM L. OTIS, CCR, the following proceedings were had, to wit:

<<<<<< >>>>>>

MR. WISE: Ms. Cox, do you want to continue with your witness.

MS. COX: We have Eric Hansen continuing this morning for us.

ERIC HANSEN, having been previously duly sworn by the Certified Court Reporter, resumed the stand and further testified as follows:

DIRECT EXAMINATION (Continuing)

BY MS. COX:

Q Good morning, Mr. Hansen.

A Good morning.

Q So we were running through issues very quickly yesterday at the end of a long day and I'd liked to briefly recap the bottom line of what we covered.

MS. SHIREY: Before you start, could I

just ask to make sure that the witness is still under oath.

MR. WISE: We are assuming he is still under oath, yes.

MS. COX: Thank you.

Q (By Ms. Cox): Can you please remind the board of the two main points of disagreement between BP and NPCA regarding issue 1 of the AQRV analysis.

A I believe the two primary issues are whether the visibility analysis should consider getting emission units that don't have an increase on the maximum 24-hour emissions as a result of the project, and for the deposition analysis, whether the emissions from affected units should be based on their potential emissions after the project.

Q And we covered visibility analysis yesterday afternoon. Can you please summarize how FLAG directs you to calculate visibility impacts analyses.

A I cited several excerpts and read several excerpts from FLAG that direct us to use the maximum 24-hour emissions for evaluating visibility.

Q In this case, did the National Park Service calculate visibility-related impacts in a manner consistent with FLAG?

A No. The Park Service evaluated annual emissions before and after the project that, in my opinion, is inconsistent with FLAG because they're supposed to do it based on 24-hour values. And it's an interesting scientific evaluation but not consistent with how applicants are expected to do their AQRV analyses for the PSD process. I think Kyle Heitkamp pointed out several very significant errors in the annual emissions as well.

Q How did BP calculate visibility impacts here?

A BP calculated them based on the maximum increase in 24-hour emissions attributable to coker heaters. The coker heaters are the only emission units that experience an increase in maximum 24-hour emissions.

Q Do you believe this approach was consistent with FLAG?

A Yes.

Q Switching gears, how does FLAG require a deposition impacts analysis to be performed?

A FLAG doesn't specify carefully how it's done, but it does specify that it's an annual issue that we are trying to evaluate how much nitrogen and sulfur is deposited in Class I areas on an annual basis and then we compare the model-predicted value with a deposition analysis threshold that is an indicator of significance.

Q Yesterday you discussed that there are new, modified and affected units. Can you remind us briefly of the

distinction between those types of units.
A I think I said -- I'm sure I said new is fairly obvious, it could only be the new coker heaters that are appropriate in this project. Modified units are those that experience a physical change or a change in the method of operation that increases emissions. It's a very precise definition. There are no modified units associated with the project. And then affected units are those downstream or sometimes upstream units that experience an increase in utilization as a result of the project, but there is no physical change or change in the method of operation.
Q And how does FLAG define affected versus modified units?
A FLAG does not define those terms. It only uses the words affected units once in one sentence in the whole document.
Q Which emission units did BP analyze to calculate that annual emissions increases for deposition from this project?
A BP analyzed all the emission units that experienced an increase in annual emissions as a result of the project. That would include the coker heaters and the affected units.
Q And how does FLAG direct you to calculate the annual emissions increases from new, modified and affected

units?
A There are enough references that we're fairly certain that we evaluate the increases from new units and modified units based on their potential to emit, so that's how the coker heaters were evaluated. It doesn't give any guidance whatsoever for affected units.
Q In his live testimony, how did Mr. Gebhart suggest to deal with the distinction between modified versus affected units in the absence of direction in FLAG?
A Mr. Gebhart suggested in his testimony and in his deposition that there shouldn't be any distinction between affected units and modified units; that they should be treated the same if there's an increase in emissions.
Q And do you agree with this approach?
A I certainly don't.
Q Can you please turn to paragraph 50 in Mr. Gebhart's direct testimony and please read the first sentence of this paragraph for us.
A He writes, "For deposition modeling, there is no specific discussion of the emission rate inputs in FLAG as there is for visibility AQRV modeling."
Q So how does Mr. Gebhart suggest calculating deposition-related impacts in the absence of guidance in FLAG?
A Well, he encourages -- he believes that it should be

based on the maximum potential annual emissions.

Q And how did BP calculate the annual emissions increases in the November supplement for deposition?

A For the coker heaters, which are the new units, it was based on the allowable emissions that were proposed in the application and they subtracted the baseline emissions as recommended by the National Park Service.

For the affected units, it was based on the projected actual emissions minus the 2014-2015 baseline as directed by Ecology's PSD manual.

Q And what were the results of the deposition impacts analysis?

A The predictions showed the deposition in all Class I areas would be less than the deposition analysis threshold.

Q And what is your perspective on Mr. Gebhart's suggestion that BP use maximum allowable emissions or potential emissions for all emission units in calculating deposition impacts?

A Well, I understand that it is appropriate for new and modified units, I agree with him there, but for affected units, that's a ludicrous concept. And I can give you an example that I hope makes it easier.

If there is an affected unit at the refinery that currently operates at, say, 5,000 gallons per year, but it could operate at 10,000 gallons a year, that's its potential design, say, so if the project, this project, allows it to increase from 5,000 to 6,000 gallons per year, I think of that as its potential after the project, that's the affect on the project, that incremental value, and that's what BP analyzed in the application. What Mr. Gebhart is suggesting is that the maximum potential of that unit should be evaluated, in other words, the 10,000 gallons a year, that is its potential emissions, but it's not characteristic, it's not indicative of what the effect of the project was, and that's what PSD is all about is evaluating a project.

Q In your opinion, is the approach taken by BP to evaluate deposition-related impact consistent with FLAG?

A Yes, it is.

Q Switching gears a little bit, BP's AQRV analysis determined that the project will have no significant adverse impacts to visibility and deposition in Class I areas; is that correct?

A Yes.

Q And the Park Service believes that the existing refinery is impairing visibility in Class I areas, correct?

A Yes.

Q What, in your opinion, is the appropriate regulatory program to address the refinery-wide existing impacts on visibility?

A The Clean Air Act established and EPA has implemented a program called the regional haze rule, and the regional haze rule considers all the sources of pollution that affect visibility in Class I areas. It prescribes certain rules and requirements for states to implement new plans that will address visibility toward a goal of no human impact or restoration of pristine visibility by 2064. And there are a series of steps in there that include basically a glide path, various check-off points, the first being 2018. The regional haze rule is more appropriate because it considers all the factors that affect regional haze, the visibility, not just the project.

Q And the PSD program is distinct from this in what respect?

A It only evaluates a single project.

Q Are you aware of any instances where the Park Service has acknowledged that the regional haze program is the appropriate mechanism to address refinery-wide visibility impacts?

A Yes. There was a recent similar situation with the Tesoro Refinery in Anacortes.

Q Can you please turn to Exhibit R-53.

A In which binder?
Q The one to your left, yes. Can you please explain what this letter is first.
A It's a comment letter from Department of Interior to Gary Huitsing at Ecology that describes a modeling analysis that the Park Service did that's similar to the modeling evaluation they did at the BP refinery. And it says how important visibility is, that it's an important value for the Park Service. And it goes on to describe a modeling analysis of the Anacortes refinery emissions and the fact that they show that there is visibility impairment in the Olympic National Park and deposition issues as well.
Q And can you please tell us what the date of the letter is for the record.
A April 26, 2017.
Q Which was after the Park Service commented on BP's coker heater project AQRV analysis?
A Yes.
Q And I would love for you to read the second-to-the-last paragraph on page 5.
A It sort of a closing summary of the document. It says, "We understand that for this modification" -- in other words, the project at Tesoro -- "the only PSD-applicable pollutants are particulate in greenhouse gasses. The

above modeling was done based on the current 2014-2015 annual emissions from the entire facility. The visibility comments provided here do not apply to the currently proposed modification. However, given the significant visibility impacts of the entire Tesoro facility on the North Cascades and Olympic National Parks, we request that the Tesoro Refinery should be considered for additional controls during the next reasonable progress phase of the regional haze rule. The most significant contributor to visibility impacts is NOx and for this reason, we would also like to commend Tesoro and the Northwest Clean Air Agency on the addition of SCR, the new boiler and the permit limit of 9 ppm."

Q So in this case, the Park Service calculated AQRV impacts analysis on an annual basis, or annual emissions, excuse me, as they did in BP's case?

A Yes.

Q But they reached different conclusions on how to address those visibility-related impacts?

A Yes. In this last paragraph, they say we did the analysis, there is an impact, but essentially we're not holding this project accountable for the impacts, and they say that they want Ecology to evaluate this issue in the next regional haze rule update of the state's

program.
Q Do you agree with the Park Service's approach in this recent Tesoro permit?
A Yes, I do.
Q And, finally, in your opinion, do you believe BP and Ecology properly evaluated impacts to AQRVs for this project?
A Yes.
Q And what did the results of the AQRV analysis for the project show?
A That Visibility impacts in all national parks in Class I areas would be less than the perceptible visibility impact criteria and that deposition impacts would be less than the threshold value of concern.
Q Do you think Mr. Gebhart's claims here regarding the shortcomings of the AQRV analysis have any merit?
A No, I don't.
Q Thank you. No further questions.
MR. WISE: Thank you. Ms. Brimmer, cross?
MS. BRIMMER: Yes, Your Honor. Thank you.
MS. COX: Can I move for admission of Mr. Hansen's direct expert testimony and his CV, please.
MR. WISE: What exhibit -- is the CV

part of his direct or --

MS. COX: It's part of it, yes, it's an attachment to it.

MR. WISE: Any objections?

MS. BRIMMER: No objection.

MS. COX: And I also forgot to move to admit Exhibit 53 and Exhibit 33.

MR. WISE: So R-53 and 33?

MS. COX: Yes.

MR. WISE: Any objections to those, Ms. Brimmer?

MS. BRIMMER: No objection.

MR. WISE: Okay. So the direct testimony, including the CV, and R-33 and 53 are admitted.

(R-33 & R-53 admitted.)

CROSS EXAMINATION

By MS. BRIMMER:

Q Good morning, Mr. Hansen.

A Good morning, Ms. Brimmer.

Q I just want to confirm that the AQRV modeling done by the Park Service shows that visibility was dominated primarily by nitrates which come from nitrogen oxides, right?

A I don't recall if it was dominated by nitrates.
Q Okay. Also I want to confirm when we are talking about deposition impacts, we're talking about two separate components, in other words, nitrogen deposition and sulfur deposition, right?
A That's correct.
Q And each of those are assessed in AQRV modeling?
A Yes, they are.
Q Now, on page 7, paragraph 19, of your testimony, if you have that in front of you.
A I'm at paragraph 19.
Q I just want to confirm, this is not an incrimate case, in other words, it is not about consumption or violation of an incrimate; that's a different consideration than PSD and that's not at issue in this case, right?
A Yes.
Q I also want to confirm your written and oral direct, that you distinguish between affected and modified units, I think that's been made clear.
A Many times, yes.
Q And that you turn to the PSD applicability rules for defining those terms; is that right?
A In the absence of any definitions in FLAG, yes, we do. We turn to, I would say, new source review rules in general.

Q Okay. And to be clear, when we are talking about PSD applicability, that means the calculations and modeling under federal rules for determining whether a source is a major modification with significant increases in emissions that would be subject to PSD permitting, right?

A Yes.

Q In other words, you're just trying to figure out whether they have to get a PSD permit, right?

A That's correct.

Q And it's after that, that the AQRV requirements in the Clean Air Act that kick in, right?

A That's correct.

Q And here it was determined that the coker heater project was subject to PSD permitting; that's this permit, right?

A Yes.

Q And I think that you have testified that Mr. Gebhart effectively is in agreement with the way the Park Service did the modeling in this case, right?

A Yes, he endorsed it.

Q One of the problems you see with that is there is no distinction like the one you make between affected and modified sources being included in the modeling, right?

A It's okay if affected units are included in the modeling if there's an increase in emissions, and so I don't have a dispute about whether they should be included in the deposition modeling, that was fine, but they should not have included the affected units in the 24-hour visibility modeling.

Q And you're saying that's because there is a distinction in the definition between modified and affected for visibility modeling?

A No, no, I'm saying it's because the visibility analyses, we're directed to evaluate visibility analyses based on 24-hour emissions, not annual, so it's fine that they include them for the annual emissions because there is an increase in annual emissions from affected units.

Q Okay. So just to be clear, you've reviewed BP's modeling and you've confirmed that they did not -- it's not that they modeled no short-term emission increase from affected units, it's that they didn't model them in the first instance because BP determined they wouldn't have an emissions increase; is that correct?

A You're going to have to break that one up for me. I wasn't quite sure who "they" was.

Q Sure. Fair enough. I started with BP so if I say "they," I'm talking about BP.

A I want to make sure.

Q That will keep me honest, all right. So I want to just be clear on what actually happened, and I'm referring to the short-term visibility modeling, okay. So am I correct in understanding that BP did not even model the affected units for short-term visibility effects?

A That's correct.

Q And they didn't even model those because they determined before that, that BP did not believe that there were going to be short-term emission increases from affected units?

A That's correct.

Q And the way BP got there --

A Let me correct that. There are no increases in emissions from the affected units that are greater than they are today.

Q And the way that EPA got to that conclusion and, therefore, omitted them from modelling is that BP took the maximum day before the project, compared it to the expected maximum day after the project for the affected units, and determined that's not going to be any change; right?

A That's correct, there is no increase in coker output so there is no way that the coker project can affect maximum short-term emissions that are required for evaluation of visibility.

Q So let's talk about the days before the project, okay?

A Sure.
Q So you looked at the affected units and you said, okay, so here is the maximum day for this unit, here is the maximum day for that unit pre-project, right?
A BP did, yes.
Q BP, sorry, yes. And you agree with that as the first step, right?
A Yes, what can the unit do today.
Q Okay. And you compared just that highest day with the highest day expected afterwards; what can that unit do after the project?
A That's correct, what's the difference.
Q So let's go back to before the project. There are a lot of days those units are operating, right?
A Yes.
Q Some of those days the units might not be operating or be operating at a reduced capacity or utilization because of the downtime we've talked about of the coker units, right?
A Well, yes, they would be -- they might be operating at a lower rate, they're certainly still operating at a higher rate, but not necessarily half, but, yes, they are probably operating lower, or they could be.
Q And those what we are calling the affected units, they don't have a uniform operation throughout, right?

A I wouldn't think so, no.
Q So it goes up and down on a day-to-day basis, right?
A Yes.
Q So after the project, I understand that BP's position is the highest day, that highest one day is going to stay the same after the project, right?
A That's right.
Q But the days that are just under that highest day, they're still not going to be at a uniform level, they're going to vary as well, right?
A That's right.
Q And so it is possible, isn't it, that you might have, for example, more days that just come up to and touch that maximum after the project?
A Yes, on an annual average, affected units will see an increase in their operation.
Q I didn't ask on an annual average. I'm saying there will be days where they come up closer to that maximum than they did before.
A There will be an increase on some days, yes.
Q And there might be days where just overall it's bumped up from what might have been medium; there might be more days that were above medium level of utilization, right?
A Could be, yes.
Q But we didn't put any of that into the model because we

determined that the max day pre and the max day post would be the same, right?
A That's correct.
Q Visibility is assessed daily, I think that was your testimony, and you emphasize that that was important, correct?
A It is, yes.
Q And that's because visibility has various components that the federal land managers care about, right?
A Yes.
Q One of those is frequency; how often is the air in the national parks obscured, right?
A Yes.
Q And some of that is intensity; how badly is it obscured, because it's not a uniform level, right?
A Yes, and that's what we focused on in the analysis first is we focused on the intensity, what change in extinction is there.
Q Okay. And then there's duration; how long is that going to last; is it a few hours, is it a week, right?
A That's correct.
Q And one of the things that the Park Service told BP is that frequency component is important and the frequency, according to the Park Service, is going to change, it's going to worsen, right?

A Frequency of what?
Q Frequency that there is a visibility effect in the two parks.
A That's what the Park Service said. With visibility, in fact, the real question is whether there's a perceptible effect. That's the key in our quality related values analysis is the effect.
Q Let me interrupt you, if I could, because I would absolutely love to ask you some questions about that.
So the Park Service uses a measure for determining when visibility is impaired and that's that .5 deciviews, right?
A Yes.
Q And they use that because it has been stated that that's what a human can perceive, that anything finer than that is not perceptible, but .5 is perceptible, right?
A That's the threshold of perception that they identify, yes.
Q That's right. So when the Park Service says there are going to be more days -- when they reach the conclusion there will be more days in Olympic National Park that the visibility will be obscured, they're putting that against that .5 deciviews, right?
A Yes.
Q So is it your understanding BP became aware of the Park

Service's modeling and the Park Service's concerns in the summer of 2016?
A Yes. I honestly don't recall the month, but I think it was soon after the June application was submitted.
Q And it was at that point in time that the disagreement about including affected units in the modeling came to light, correct?
A Yes.
Q But BP never changed the modeling to conform to what the Park Service's interpretation would be of including the affected units in the visibility modeling, right?
A That's correct.
Q Do you know if those affected units had been included in BP's modeling, that it would have generated similar results to what the Park Service got?
A I don't know. I don't believe BP ever did that modeling.
Q So you disagree on the Park Service's reading and application of its own FLAG guidance; is that your testimony here today?
A I think the Park Service is free to do whatever analysis they want. I don't think the analysis that they did complied with FLAG guidance that's used in PSD permitting.
Q So just to be clear, that statement means you disagree

with the Park Service's reading and application of its own guidance; is that right?
A As they applied it right here, yes.
Q Do you think the Park Service was confused on how to apply its own guidance?
A I believe that the Park Service was on a mission and they wanted to present -- I think they were making a case for additional emission controls at BP and that they were providing a scientific analysis that supported their position, not trying to duplicate the procedure that applicants followed in PSD permitting.
Q To be fair, that could be said about BP, too, right; they want to do the project, they don't want to put SCR controls on.
A They want to do the project, certainly, and they found that the SCR was not cost effective.
Q Right. Despite what the Park Service was discussing, BP has very firmly said we don't want to do SCR, right?
A That's correct.
Q I would like you to refer to page 9, paragraph 26, of your testimony, please. I just want to be sure that I understand your testimony. A lack of physical change to a unit is not conclusive of whether there will be a change in emissions at that unit from the project, right?

A That's correct.
Q And, in fact, I think at page 12 of your testimony, lines 25 and 26, you do note that average daily utilization and emissions may increase, including at affected units, right?
A Yes.
Q And that those short-term emissions at affected units could change in their frequency or their duration or their intensity, right?
A Would you repeat that.
Q Sure. I will break it up. Maybe that's easier.
A Okay.
Q Short-term emissions at those affected units, day-to-day, we were discussing earlier, could change in their frequency, right?
A Daily emissions can change, yes, they will change.
Q In other words, from pre-project. Let me give you that frame of reference.
A Daily emissions will change. There would be an increase in utilization.
Q Okay. And those changes could be, and I think that they might achieve a certain level of emissions more frequently, for example?
A Yes.
Q Or the duration of a certain level of emissions might

change, correct?
A Yes.
Q Or the intensity, in other words, how high those emissions go could change?
A Well, same thing; they could be higher on any given day.
Q Right, but they won't exceed that single daily max that you looked at.
A That's correct.
Q I would like you to turn to Joint Exhibit 11, that's the FLAG guidance that we've been spending lots of quality time with, page 24 in particular, and I think that's JE Bates number 1147. I think I have that memorized. And I think that Ms. Cox had you read part of or most of a paragraph on that page yesterday. Do you recall that paragraph?
A I don't recall -- I think I read several.
Q Okay. Well, let me take a look at my copy and then I can get you right there. So if you look on page JE1147, look at the right-hand column, the paragraph in the middle of the page that begins "Applicants," you remember reading that yesterday, right?
A Yes.
Q There is actually a footnote attached to that, isn't there?
A Yes.

Q And that footnote is Footnote 6, right?
A Yes.
Q And that includes a caution about modeling, right?
A Yes, it appears to.
Q And then I would ask you to turn to P-7. That's in the exhibit book that is the NPCA exhibits, it's one of the green ones. Let's go to the second page of that. I think you discussed that with Ms. Cox yesterday as well, right?
A I did.
Q And I think your testimony was you had not had occasion in the past to look at the response to comments; is that right?
A That's correct.
Q And I would ask you to refer to the paragraph at the bottom of that page, and take some time to read that, I don't need you to read it out loud, but just take a moment to review that, please.
A Okay. I've read it.
Q Thank you. Would you agree with me that that is further explanation or additional explanation for what the FLMs are discussing in Footnote 6 of FLAG? And you can take your time to compare those as necessary.
A Yes.
Q And I think on P-7, would you agree with me that the

federal land managers are noting that there can be short-term emissions increases at units that are not physically modified, right?

A I think so, yes.

Q And they're saying basically they want to know what those are, right?

A What I take from this paragraph is that the applicants should calculate the baseline as suggested by the Park Service in their comments after the 2016 application was submitted, that's what I derive, that's all I derive from this.

Q Okay. Let's explore that. So the baseline would be actual emissions before the project, right?

A Yes.

Q But BP here never looked at actual emissions as described in P-7 for the affected units before the project, never subtracted those actual emissions from the expected emissions for the affected units post-project, right; they never did that for the visibility modeling?

A No, because there wouldn't an increase in emissions.

Q I'd like to turn to some of your testimony about regional haze and the regional haze program. The PSD requirements for AQRVs and the federal land managers' role that we're discussing in this case is the PSD

section of the Clean Air Act, right, it's the PSD requirements?
A Yes.
Q And the haze requirements and the federal land managers' role in haze is an entirely separate section of the Clean Air Act, right?
A Yes, that's correct.
Q That's got its own program and its own set of rules from the PSD program and rules, right?
A Yes.
Q And there's nowhere in the Clean Air Act that suggests one substitutes for the other, correct?
A Not that I know of, no.
Q And there's nowhere in the permitting rules that suggests one substitutes for the others, correct?
A Correct, not that I know of.
Q So with that, let's turn just quickly to your testimony about the Tesoro exhibit and the Tesoro example.  And I think you referenced this in your direct testimony. Tesoro had already agreed to apply SCR, correct?
A Yes.
Q And, in fact, Tesoro had also, I think, noted in the letter there were going to be significant emissions reductions in VOCs, or volatile organic compounds, correct?

A I believe that was correct.
Q And that's a pretty significant environmental benefit as well, isn't it?
A Yes, it is.
Q And that would be different than the situation here, right? In other words, Tesoro's agreement to apply SCR is different from what BP's position on SCR is in this case, right?
A On SCR, yes, that's correct.
Q And when you referenced the part of that letter about regional haze and the haze program, just to be clear, the statements in the letter about future review and possible future actions by Tesoro pursuant to regional haze is in addition to the application of the SCR and the VOC reductions, right?
A I presume so.
Q Can you refer to page 13 of your testimony, please. On both that page of your testimony and in some of your direct testimony yesterday, I think you were talking about the data that the Park Service used in its modeling, right?
A Yes.
Q And I think yesterday you asserted that the National Park Service used annual data for its visibility modeling, right?

A Yes, I did.
Q But they did divide that by the hours, right?
A Yes, they did.
Q Are you aware of the fact that the Park Service sought emissions information for its modeling from BP?
A I'm not aware. I am aware that they derived some of their, I think most of their emission information for their modeling from the June application. I'm not aware of other requests.
Q BP never gave the hourly emissions data to the Park Service, right?
A I don't know. Certainly the hourly data for the coker heaters were available, that was in the application.
Q That was in the application?
A Yes.
Q Are you aware that the Park Service referenced Appendix C of the application for its emissions increase input?
A Yes.
Q I just want to confirm in some places in your testimony, and I apologize, I don't have specific paragraphs, so if you don't recall, that's fine, but I believe you referenced BACT in some of the same places where you're talking about affected and modified units. BACT is a separate consideration from Class I AQRV analysis, right?

A Yes, determining what BACT is, is a separate issue, but BACT determines what the emission are that are used in the air quality related values, the visibility assessment deposition.
Q When you looked at the Q/d analysis that was done by BP, did you determine that the emissions used in the Q/d analysis also did not include short-term emissions from the affected units?
A Yes.
Q Could you turn to JE1197, and that's the FLAG guidance again, and it's page 74 of the FLAG guidance, otherwise known as JE1197. I'll try to get you the column in just a moment. If you look at the left-hand column on that page under 4.3, Contextual Considerations, do you see that?
A Yes.
Q Do you agree with me that one of the contextual considerations that the FLMs do that's listed there is what the current situation might be with AQRV impacts in a Class I area and what the trends are?
A Yes, I recall reading that in FLAG.
Q If you turn to page 15, paragraph 47, of your testimony, please. I think this is where there's some discussion of the lean oil absorption system. Are you there?
A I'm on page 15, yes.

Q Paragraph 47.
A Okay.
Q I just want to confirm your understanding that the lean oil absorption system will treat 44 percent of the coker off-gas, right?
A That's my understanding, yes.
Q But that's not required by the permit; that's voluntary in the permit, right?
A Well, it's not required by the permit, but in reality --
Q I just want to ask you about the permit itself. So the permit says that's voluntary, right?
A The permit doesn't mention it, doesn't say it's voluntary, it doesn't prescribe that.
Q Okay. Let's take a minute and look at the permit. It will take me a minute to find it, so just give me a moment. My apologies. I think it's in the technical support document for the permit. Do you recall a statement that it's a voluntary component of the permit in the technical support document?
A I don't, but I'll believe you.
Q That's okay. You don't have to. We're looking it up. We'll come back to it.
I think during your direct testimony, you talked about the fact that BP changed the baseline in their November supplement modeling to conform to what was

recommended by the Park Service. Do you recall that?
A Yes, I do.
Q And I think you were referring particularly to the deposition modeling, correct?
A I don't recall if I was referring to the deposition modeling, but I know that the modeling for both visibility and deposition were adjusted to account for the different baseline that the Park Service recommended.
Q Okay. And to be clear, that visibility modeling included only the coker heaters, right?
A Yes, but the baseline still was changed.
Q Okay. But, in fact, BP's November modeling changed the baseline but applied a scaling approach from the PSD applicability rules, correct?
A I don't know about the scaling approach from -- yes, they applied a scaling approach. I don't know that it was from the PSD rules that you suggest.
Q Okay. But the scaling approach means that it wasn't actual, right, wasn't just the actual emissions pre-project then?
A I'm not sure I understand, because I think you were talking about future.
Q My apologies. Yes. Yes. So they applied the scaling approach to compare the actuals pre-project to the post-

project, correct?
A Well, it's a projected actual --
Q Right.
A -- and what they do, what we asked them to do, we, the applicant, Kyle asked BP to identify what the effects of the project would be compared with the baseline that the National Park Service suggested or requested that they use, what's the effect of the project.
Q I understand. But that is not the approach that was used in the June application, correct, for determining what the projected future emissions would be, right?
A That's correct. In the June application, it was based on a baseline that's required by state law.
Q Okay. I think we're both getting mixed up, so I'm going to break it down. So in the November supplement, BP changed the baseline it used for pre-project emissions, right --
A Yes.
Q -- to conform to what the National Park Service recommended, right?
A Yes.
Q But for post-project emissions, BP also made a change, and that's where it applied that scaling concept, right?
A Individually by unit. It increased the emissions from each affected unit by an amount that it felt would be

the maximum the project could affect that emission unit.
Q But that's not what was done in the June application. There was a different potential-to-emit calculation that was done in the June application, correct?
A That's correct.
Q And that scaling approach was not the approach that was recommended by the Park Service?
A I'm not sure I understand. Did the Park Service make a recommendation?
Q I guess that's what I am saying.
A I don't recall that they made a recommendation on that scale -- regarding a scaling approach.
Q That's what I was asking you, is that the recommendation they made was for the pre-project baseline approach, right?
A Yes.
Q I just have a few remaining questions and they're about exhibits in the NPCA book, so let's turn to that, please. First, a few preliminary questions. Would you agree with me that the PSD applicability modeling rules, in other words, the rules for how you do calculations to determine whether PSD applies, do not apply and should not be used in AQRV modeling?
A AQRV modeling does not provide definitions that enable us to do our analyses, so in the absence of definitions

in FLAG, we do turn to any source we can get, and the best parallel we can find is those definitions that we use for new source review.

Q And, in fact, there was specific direction from EPA not to use the PSD applicability rules when modeling for AQRV assessment, right?

A You will have to point me to that.

Q Okay, I will. Are you aware of the fact that the Park Service also informed BP that BP should not use the PSD applicability rules?

A Sorry, that's my phone.

Q Do you want to take a minute. (Pause) So let's read that question back.

(Question read back by the Court Reporter.)

A The PSD applicability rules --

Q I'm not asking for an explanation of the rules. I want to know if you were aware that the Park Service told BP they should not use the PSD applicability rules in their AQRV modeling.

A It was limited to -- they said we shouldn't use the same baseline that we apply in PSD applicability, that's the extent of it.

Q So that's your testimony that that's the specific thing that the Park Service told BP about PSD applicability?

A That's my recollection, yes, that was the most significant difference.
Q And are you aware of EPA's caution to BP in its comments that the PSD applicability rules do not apply to AQRV modeling and assessment?
A I don't recall it, but I recall that there were comments from EPA, but I don't recall that one.
Q So I'd like you to turn to Exhibit P-110 in that NPCA book.
A I'm there.
Q So this looks like a series of emails from 2017 and I think you are on this series of emails, correct?
A Yes, I initiated that, I think.
Q Okay. So let's turn to that first email in the sequence in October of 2016. Do you recall that that was about the time that the Park Service supplied some written comments to BP and Ecology about the Park Service modeling and the disagreement with BP about AQRV impacts?
A Based on the text of my email, yes, that clearly was.
Q And at that point in time, I think your email was raising questions about this use of PSD applicability rules and that you had previously been unaware of that advice from EPA to not use them.
A Yes, certainly that's correct, that was a surprise.

Q Okay. And, in fact, that EPA preamble that's referenced here is from December of 2002, right?
A That's correct.
Q That's when the PSD applicability rules had a major change, right?
A Yes.
Q And the administration at that time had made some changes that allowed certain things to occur in the calculations, for example, taking advantage of contemporaneous emissions or loosened up some of the rules with respect to what baselines could be used, for example?
A It changed the rules for what the baselines could be, yes.
Q And I think there's a response from a Bliss Higgins, and I believe that's someone at Ramboll, right?
A It is.
Q Is it correct that Ms. Higgins used to be the head of Louisiana DEQ; is that right?
A She was.
Q And I think that her advice back was, yes, EPA has over the last 15 years been consistent on that point that the PSD applicability rules don't apply to AQRV analyses, right?
A That's what she said.

Q And then I want you to turn to the first page, which is an email with a number of people, and I think it's actually from Kyle Heitkamp to Ms. Higgins, but you are on that list, right?
A I was.
Q And there's some additional discussion there, right?
A Yes, there is.
Q And I think Mr. Heitkamp there is discussing the ways that the emissions increase calculations for the AQRV modeling analysis were using some of those PSD applicability rules, right?
A Yes.
Q And it's correct, isn't it, that but for changing the baseline in the November modeling as you've described for the pre-project emissions, BP did not change any of the other calculations that it did with respect to the AQRV modeling?
A Oh, no, it did change. In the November application, it changed both the baseline and, as I recall, it reduced the proposed sulfur limit for the coker heaters a little bit from 40 to 37 pounds an hour, and it also changed the way it calculated the emission increases from the affected units.
Q Right, it did that scaling approach, right?
A Yes.

Q That's an approach from the PSD applicability rules as well, isn't it?
A You asked that before, and I don't understand what you're saying when you ask that.
Q I'm saying that allowing that approach is something that is allowed or utilized sometimes in the PSD applicability applications, that's what I am asking you, if that's correct?
A For modified units, you are allowed to project the actual emission increases, so I'm not quite sure what you are referring to because these are not modified units.
Q So when you're making that projection, you can use that scaling approach, is that what you're saying, instead of potential to emit? It's different than the --
A Yes, that's correct, it's different from potential to emit that applies to new and sometimes modified units.
Q That is what I was asking.
A Yes, that's right.
Q I think it's your testimony that you've been involved in reviewing AQRV assessments during the course of your career, correct?
A Yes.
Q You hadn't done the modeling yourself, but you had a lot of experience reviewing them, right?

A Correct.
Q And you've got extensive experience in PSD permitting?
A I believe I do, yes.

MS. BRIMMER: I'd move admission of Exhibit P-110, please.

MR. WISE: Any objections?

MS. COX: No, Your Honor.

MR. WISE: P-110 is admitted.

(P-110 admitted.)

Q (By Ms. Brimmer): I'd like you to turn to P-103, please.
A I'm there now.
Q Now, in anticipation of some discussion on this, I know that this email goes back a ways to a date before work on this permit, but because you've been testifying some about BART and how that may or may not, and haze, may or may not apply to this project, I want to ask you just a couple questions about this.

MS. COX: You Honor, we're going to object to any questions about this email. It's from 2010 before the project was even in early stages of the application preparation.

MR. WISE: Ms. Brimmer.

MS. BRIMMER: Yes, Your Honor. We believe that this is relevant to, one, the testimony about the interplay with respect to regional haze and PSD permitting, and there's been testimony that these issues about AQRV, as it affects the parks, are better dealt with in the haze program, and so it does reference BART, which is a concept in the haze program, and, more importantly, it goes to credibility issues with respect to this witness and BP more generally.

MR. WISE: I'm going to sustain the objection. I just don't see the relevance here, I don't see the connection to regional haze, and I mentioned earlier that I was not inclined to admit these earlier exhibits for the purpose of attacking BP's credibility, so I'm going to sustain the objection.

MS. BRIMMER: Understood, Your Honor. I would make an offer of proof. We need to make sure that while this is not admitted into evidence, this email is available in the record in the event of an appeal, so I would make an offer of proof. We can either leave the written exhibit in the exhibit books, but understand it is not admitted into evidence and will not be considered by the board, or I can read the email into the record, whatever you prefer.

MR. WISE: I believe our procedure is on not admitted exhibits, we leave them in the notebooks so they would go up on appeal; it's just they're not admitted into our consideration.

MS. BRIMMER: That's great. That's a perfectly workable solution. Thank you.

Q (By Ms. Brimmer): Turn to P-99, please. Are you there?

A Yes.

Q This looks like an email from 2016 from you to Mr. Heitkamp, correct?

A And others, that's correct. Yes, to Kyle.

Q And do you recall this email?

A Barely, but yes. I recognize it.

Q Okay. If you want to take a minute to review it and then I will ask you a few questions.

A Yes. This was the big gulp moment when we received the information that the 2002 preamble baseline calculation should be applied.

Q I just wanted to confirm a few points here. You note there's some concern, in this middle paragraph, about how this might affect the review process on the project, right?

A Yes. We had done the application based on state law and this was a wrinkle in it because they revealed a preamble citation that said we should have done it differently.

Q And were there concerns about what that revised modeling might show?

A Yes. It was going to reduce the baseline and, therefore, suggested that there were higher impacts for the project.

Q And then in the last paragraph, you said because we don't calculate the short-term emission increases based on annual baseline values, you don't think it has a bearing on your visibility assessment, which was the primary concern raised by the National Park Service. Do you see that?

A Yes, I do.

Q Am I reading that correctly, it's just kind of a confirmation of what we've been talking about quite a bit here is that BP did not even model short-term increases for visibility assessment for all the units?

A Only the coker heaters that had the increase in maximum emissions.

Q And you do acknowledge that was in fact the primary concern raised by the National Park Service, right?

A I don't recall -- You mean that the affected units were not included?

Q Well, I'm just trying to confirm the statement in the email, of that sentence in that last paragraph.

A I don't see where it says that.

MS. BRIMMER: Okay. I would move admission of P-99, Your Honor.

MR. WISE: Any objections?

MS. COX: No objection.

MR. WISE: P-99 is admitted.

(P-99 admitted.)

MS. BRIMMER: I have nothing further, Your Honor. Thank you. Thank you, Mr. Hansen.

MR. WISE: I think this is a good time to go ahead and take our mid-morning break, so we'll come back at 10:30.

(Recess from 10:10 a.m. to 10:30 a.m.)

MR. WISE: Ms. Cox.

MS. COX: Thank you, Your Honor.

REDIRECT EXAMINATION

BY MS. COX:

Q I'd like to clarify just a couple things that came up during cross. In the June application, the analysis BP followed was consistent with FLAG and the Washington regulations, correct?

A I believe so.

Q And BP revised the November supplement in response to National Park Service comments, correct?

MS. BRIMMER: Objection. This is redirect. It's leading.

MR. WISE: I'll allow it.

Q (By Ms. Cox): I can rephrase. Did BP revise the November supplement in response to National Park Service comments?
A Yes.
Q Does Mr. Gebhart agree with the visibility calculations for the new coker heaters in the November supplement that BP submitted?
A His testimony, his written testimony, implies to me that he did agree with it.
Q So the sole issue is whether BP calculated emissions increases from the affected units using the equation NPCA suggests.
A Yes.
Q And what is the equation that NPCA suggests using to calculate emissions increases from affected units?
A That the affected units be evaluated based on their potential emissions from the unit rather than what the project is going to cost.
Q And what would happen if you applied that calculation to a unit that is in no way affected by a project, so in no way experiences emissions increases on a daily or annual basis from a project, what would that equation show?
A It would distort the effect of the project for sure because the application would normally say there is no increase in emissions and you would be asked to apply

the potential emissions from that unit.

Q I would like to now turn to page 19, paragraph 51 of your direct testimony.

A Page 19.

Q We've heard a lot today about how BP's calculations take into effect the potential increases on various days, not the peak maximum worst-case day increase, but whether there are incremental increases on certain days on downstream affected units as a result of the project and how those are taken into account. Can you describe Figure 1 and how FLAG directs you to calculate visibility-related impacts.

A Figure 1 tells us to evaluate the newer modified source by first doing the Q/d analysis, and if you pass, you can presume no impact; if you fail, if Q/d is 10 or greater, it's greater than 10, then you go to the more detailed analysis, which was what was included in BP's analysis. If the analysis shows that the impacts are less than the visibility criterion, then you can again presume no impact. If the analysis shows that the impacts are greater than that 5 percent indicator, then you go on to evaluate context, and context is where you start talking about how many days does this occur, what's the extent of the impact geographically, and what are the other trends in the national parks. So those

contextual considerations occur after you fail the test, not before.
Q And yesterday we read several passages in FLAG regarding the visibility impacts analysis, and many of them talked about the maximum 24-hour emissions from a project. Can you describe the importance of the maximum 24-hour emissions and the impacts on Class I areas?
A It's the maximum 24-hour emissions that cause the impact. FLAG says over and over thou shall use maximum 24-hour emissions to calculate visibility impacts, and the maximum 24-hour emissions attributable to the project.
Q And would average daily emissions give you a similar analysis as maximum daily emissions?
A It does not, no. That's why they specified maximum so many times.
Q Would that adequately show the level of intensity and effect of visibility emissions on a Class I area if you looked at average daily emissions?
A Generally not.
Q And that's why you look maximum daily emissions?
A Yes.
Q Thank you. No further questions.
MR. WISE: Any other redirect? Board questions? Ms. Marchioro.

EXAMINATION

By MS. MARCHIORO:

Q One thing I wanted to ask you is about that Tesoro letter. Have you had a chance to review the letter that the -- it was Exhibit R-53 -- regarding the Tesoro plant in 2017?

A Yes. I read from that on the third page or the last page.

Q Well, had you seen the document before today?

A Yes, I have.

Q And have you read it before today?

A Yes.

Q Okay. I'm just trying to understand if you were looking at -- and maybe you can tell me -- is the modeling analysis that the National Park Service was doing for the Tesoro facility the same as the modeling analysis it did for BP?

A It's generally the same concept, yes.

Q Okay. And I'm trying to understand from your experience, is that the same modeling that the NPS has been applying to these types of projects, in your experience, over the last 15 or 20 years?

A Well, the Park Service hasn't done independent modeling that I am aware of on projects here in Washington over the last 15 or 20 years. This is the first time in my experience that they have decided to conduct their own modeling for the BP project and for Tesoro. There may be other occasions, but I never saw it.

Q Okay. So in terms of if I was trying to come up with an understanding of the Park Service's consistent view on this particular issue, I have two potentially different answers.

A Yes.

Q And I'm just curious, is it a timing issue that one came in 2016 and one came in 2017? We haven't had an election. Is it a change in administration that drove that, do you know, from your experience?

A That the letter came?

Q That the --

A Oh, oh, so perhaps that the Department of Interior had a change of heart?

Q Yeah.

A I couldn't say.

Q Thank you for that. And so in terms of the modeling, it looks like the NPS used CALPUFF and some other different modeling. I know that one. Are those models different than the models that were run by Ramboll? Did they use a different modeling software or just different inputs?

A No, just different inputs. No objections to the way they ran the model.

Q Is that a standard industry model?
A It is.
Q And so we were talking about physical change, and on R-30, page 18 --
A Sorry, I don't know which notebook.
Q It should say BP exhibits, and R-30 is Ecology's guidance?
A Okay.
Q And at page 18, I'm just trying to understand, it talks about an increase in utilization as a result of the project.
A Sure.
Q So that's that first full paragraph under subsection B. What does that mean to you?
A We can forget about the confusing language about aggregation. That's not relevant here. It's affected emission units. We define affected units as those that will experience an emission increase as a result of the project, so it's an increase in utilization, so if, for example, the coker heater were able to put more product out on a given day, those downstream units would feel an increase -- they could process more and have higher emissions, but the coker heater can't. However, because of the elimination of the dips that we have been talking about in that one line due to online cleaning, they can

process more material over the course of the year so there is an increase in annual utilization.
Q I'm sorry, can you say that again. It was a little soft for me. There is an increase or there is not?
A There is an increase in utilization of the affected units over the course of the year, and that's why it's included in the deposition analysis.
Q But then we get back to the issue of annual versus daily max or visibility versus --
A Correct.
Q And so what would constitute a physical change, in your opinion, of the unit?
A Changing the burner so that the unit can fire harder. Sometimes as little as changing the plumbing that goes into the unit so that it can process more fluids. There are a number of things that can affect the firing rate. As mentioned yesterday about physical change, it's usually a plumbing or firing rate issue or something like this.
Q And so in this instance, there may be more intensity of use because there's no downtime --
A In this case.
Q -- in terms of the downstream units are going to be being used, more off-gas, more --
A No. More product.

Q More product.
A Over the course of the year, but no more on a given day than they can process today, than they receive today.
Q And then in your understanding, does Ecology run its own separate modeling?
A They have very skilled dispersion modelers there who review the modeling that applicants submit. Whether they completely remodel it independently or not I think depends on the situation, but they certainly review the inputs and the assumptions that go into the modeling every time.
Q Does that include the AQRV modeling?
A Yes.
Q Thank you.
MR. WISE: I had some questions, just a couple here.

EXAMINATION

BY MR. WISE:
Q Back to the regional haze. I believe it was your testimony that you thought that was a sort of a way of addressing some of National Park Service's concerns?
A Yes, I do.
Q Okay. And there was that Tesoro letter that you read from. Are you aware of any other letters like that at

other refineries?
A I'm not.
Q And I think you said that it wasn't in the -- there was a set of rules that you said, that that regional haze as a substitute, there is no law that you know of that supports that concept of addressing AQRV impacts through a regional haze program?
A Well, that's its purpose is to address the existing problems through a regional approach, so, yes, that's its purpose is to address visibility.
Q But are you aware of any specific place where it says -- where it supports the idea of substituting -- I don't know, that question is not coming out right.
Are you aware of National Park Service, any communications for them on the concept of the regional haze in this project?
A On this particular project. I have to think for a minute.
Q Sure.
A So the question is whether there is any communication from the Park Service related to the regional haze rule and this BP project?
Q Yes.
A I don't recall any.
Q Okay. Just one other question. Could you go back to

P-99. It's in the larger notebook.
A The green notebook?
Q Yeah, green notebook. It was a 2016 email from you.
A Yes.
Q And in the third paragraph there, I just was curious about a parenthetical that's in that first sentence. It says, "Our visibility assessment which is or was the primary concern raised by NPS." Do you remember why you put the parenthetical in there "Or was"?
A Let me think about that. I honestly don't. I don't know why I put that.
Q Okay, you don't recall. That's all I have.

Ms. Brown.

EXAMINATION

BY MS. BROWN:

Q I think you said that there should be different treatment for affected units versus new or modified units.
A How we address them in the application?
Q Yes.
A Yes.
Q And why is that? I think I know the answer to this, but I want to hear the answer.
A Well, we follow the rules. The permit applicants need

to follow the direction that's either in a FLAG document, where available, or in other new source review rules, so EPA, Ecology, they have rules, and we have to be very careful about following the rules and they specify different ways of calculating emissions for modified or affected units.

Q And then on this regional haze rule, you might not be the best person to ask this question of, but do you have sort of a general idea of what tools are available to regulatory agencies to implement things under the regional haze rule?

A Well, yes. Alan Newman is probably the expert on that, he'll be testifying later, but there is a state implementation plan for dealing with visibility and it addresses reductions in emissions from industrial facilities, including BP. There were changes to BP permits to reduce its emissions as part of this state program, visibility program. There is significant reliance on reductions in sulfur content in motor vehicle fuels, that's one of the big ones. It tries to touch on all the different sources of emissions in the region, not just industrial facilities. But I would say that the attempt -- the benefits from fuel improvements, quality of fuel, lower sulfur, lower benzene reductions that actually allow the use of catalytic controls, that's really one of the major sources of visibility improvement.

Q So under this program, can Ecology go back and require emission reductions? I know in general for air quality matters, that Ecology can't usually go back and require emission reductions unless the facility is doing something like modifying something or --

A No, I believe Ecology does have the authority to do that. There is another update coming, and I'm not certain, I think it's 2019, that the regional haze rule requires states to revisit their program to ensure continued progress. They talk about a glide slope toward that ideal visibility scenario in 2064 and they want to make sure that there's progress on that glide slope and that it continues, and so I think Ecology revisits the program in place and could very well include additional restrictions on industrial facilities. That's why the Department of Interior said we'll be back and we'll talk about that in the next update for Tesoro.

Q So BP could be asked to reduce under that regional haze program?

A I believe so.

Q And then I understand that the Park Service is saying that there are more days that visibility will be obscured from BP?

A There are more days when there would be an effect from BP. The distinction I make is that we're interested -- as practitioners, we want to identify whether or not there is a perceptible change, and that's that 5 percent change in extension, 5 percent change in visibility in a Class I area. It's true there could be a change of 1 percent effect to 1.2, but we're interested in whether or not it exceeds that criteria of 5 percent, and it does not.

Q So the way the Park Service calculated it, though, they concluded that it would?

A Yes, they did, because they used that annual emission inventory.

Q Right. So they concluded it would be 5 percent or --

A They did find a couple of places or a couple, and I think it was only in Olympic National Park, where it barely exceeded 5 percent.

Q And then so on this AQRV modeling, I understand that it's provided for in the law, but are there any rules about how to do it or is all we have is the FLAG guidance?

A All we have is FLAG guidance.

Q So there aren't any CFRs or anything that say how this is to be done?

A The federal rules and the state rules require us to do the analysis; it doesn't specify how. It doesn't provide prescriptions on how to do it.
Q So the only guidance is in this FLAG document?
A FLAG and whatever we can derive from state law for new source review programs.
Q So you're kind of using that by analogy?
A By necessity, yes.
Q All right. Thank you.
MS. MARCHIORO: I have another question.

EXAMINATION

BY MS. MARCHIORO:
Q Ms. Brown was asking you about the NPS calculation, that there would be an increase in visibility impairment, if I understood that correctly, and your answer is that they use the annual data to achieve that.
A That's how the National Park Service did their modeling.
Q What did they do in the Tesoro, from your understanding?
A I believe they applied the same approach.
Q And then did they reached the same conclusion?
A Yes.
Q Okay. Thank you.
MR. WISE: Okay. Any follow-up to

board questions. Ms. Brimmer.

MS. BRIMMER: Yes. Thank you.

FURTHER EXAMINATION

BY MS. BRIMMER:

Q Mr. Hansen, I'd like to start off with discussing some of the questions from Judge Wise and I think a little bit touches on some questions from Judge Brown as well, and that's about regional haze, and I think you said something about, in response to Judge Wise, I think he was posing questions to you I think following up on some of our discussion about you can't substitute one for the other, in other words, there is nothing in the Clean Air Act that says that the regional haze section of the Clean Air Act is somehow a substitute for the PSD obligations of the Clean Air Act. Do you recall that?

A Yes.

Q Okay. And I think in response to Judge Wise, I'm sorry, I'm scribbling notes as fast as I can --

MR. WISE: And my question was totally opaque, so --

MS. BRIMMER: No, no, we were tracking.

Q (By Ms. Brimmer): You said something about that's its purpose. Do you recall that?

A I need a little background.
Q That's what I captured, and I think you were talking about the purpose of the regional haze provisions is to address AQRVs; is that a fair characterization of what you were maybe saying there?
A The regional haze rule is to address regional visibility issues, yes.
Q Right. So let me get to the nugget of that. So let's just be clear. There are the PSD provisions in the Clean Air Act, those are at 42 U.S.C. Section 7475, and that's what's going on in this case, right, the PSD permitting requirements?
A I'm not sure I understand what you just cited.
Q Sure. Would you agree that 42 U.S.C. 7475 are the PSD permitting requirements in the Clean Air Act?
A I have to admit that we focus on the CFR 52.21.
Q Okay. Would you agree the Clean Air Act is the foundation for the CFRs?
A Yes.
Q So putting aside the specific cite, there is a specific provision in the Clean Air Act that controls PSD permitting, right?
A 52.21 tells us how to do PSD permitting.
Q I'm talking about the Clean Air Act.
A I believe you. Yes, of course.

Q You don't have to believe me. Do you --
A I have to say that my focus is on the CFR, not the Clean Air Act itself.

MS. SHIREY: I am going to object because these questions are going to legal conclusions.

MR. WISE: Would you like to rephrase.

MS. BRIMMER: I don't think I am asking for a legal conclusion. Mr. Hansen has presented himself as an expert with multiple decades of experience on Clean Air Act permitting, including PSD permitting, and he's testified on regional haze. I am not asking him for a legal conclusion, I'm trying to get at his understanding of these two programs and where they arise.

MR. WISE: I will overrule the objection. Go ahead.

MS. BRIMMER: Thank you.

Q (By Ms. Brimmer): So I am sorry, Mr. Hansen. Let's start over.
In the Clean Air Act, there is a separate section for PSD permitting; is that your understanding?
A That is my understanding.
Q And that's really what we're talking about here today. It sets up the AQRV modeling requirements and it sets up the federal land managers' involvement in that process,

right?

A Yes.

Q And it provides for an affirmative responsibility for the federal land managers to ensure that those AQRVs are protected, right?

A Yes, it does.

Q There is an entirely separate section of the Clean Air Act, I won't throw out citations, and that concerns regional haze, right?

A Yes, it does.

Q And that section, I think, as you talked about it just now, it is more of a program kind of thing, it's a regional approach to haze, right?

A Honestly, I am aware of the fact that there is a regional haze rule, we were involved in the implementation of the BART plan of that, I have reviewed the state's implementation plan for the regional haze rule, but I did not have any reason to trace it back to the Clean Air Act.

Q Okay. So in your response to questions from Judges Brown and Wise about haze, I think you said that BP had been subjected to some controls as part of the regional haze program; is that an accurate characterization?

A Yes.

Q And I think you used the word BART, and that stands for

best available retrofit technology, right?
A Yes.
Q And that's a one-time application under the regional haze rules, right?
A I believe that's correct.
Q And the continuing obligations under the haze rule go primarily to the State of Washington, right?
A That's my understanding.
Q And the State of Washington has a continuing obligation to plan and strategize how to clean up the air in the Class I areas, right?
A Yes.
Q But there's nothing in those provisions, is there, about imposing additional requirements on a source like BP outside of PSD permitting, right?
A My understanding is that Ecology has the discretion to develop a program that most effectively addresses the visibility problem, so if there were no issues with respect to industrial sources, there wouldn't be any need for any further action there.
Q I don't think that was my question. Even if Ecology in its strategy thought that perhaps major sources were still causing a problem, the only way it can get at that is through PSD permitting; it can't knock on BP's door and say, "Oh, by the way, we're going to impose more

stringent BART controls on you because of the regional haze strategy," right?
A My understanding is that Ecology could do that and that's why the Department of Interior said we'll be back at the Tesoro facility and suggested that they would revisit the issue then.
Q Where in the law does that understandings come from?
A I don't know the law.
Q Okay. Just a very quick question to follow up on Judge Marchioro's question. She had you reference R-30, page 18. Is that still in front of you?
A I should know by now, but which binder is that?
Q That's in the BP exhibit binder.
A Okay.
Q So I think you were talking about some of the requirements on page 18 with Judge Marchioro, correct?
A Yes, we were.
Q I want you to turn back to page 5, please. Are you there?
A Yes.
Q And I want to be clear, the provisions that you were discussing with Judge Marchioro fall under that PSD applicability heading, correct?
A That's correct.
Q Thank you. I have nothing further.

MR. WISE: Ms. Shirey, any follow-up?

MS. SHIREY: No.

MR. WISE: Ms. Cox.

MS. COX: I have one.

FURTHER EXAMINATION

BY MS. COX:

Q I would just like to clarify or give you a chance to clarify your response to a question from Judge Marchioro about the Tesoro example. In that situation, the National Park Service determined that the project would have an adverse impact on visibility from the project or the facility as a whole?

A I would want to refer to that letter again before I answer.

Q Sure. It's R-53.

A I believe the response referred to the project, but I want to make sure.

Q And you can look again on page 5, the second-to-the-last paragraph, if that helps.

A Yes. It said, "The visibility comments provided here do not apply to the currently proposed modification." They were referring to the impacts from the refinery as a whole.

Q No further questions.

MR. WISE: Thank you, Mr. Hansen. You may be excused. So is that the extent of BP's witnesses?

MS. COX: Yes, Your Honor.

MR. WISE: And then, Ms. Shirey, are you ready with your witnesses?

MS. SHIREY: Yes.

MR. WISE: Please call your first witness.

MS. SHIREY: I call Alan Newman.

ALAN NEWMAN, having been first duly sworn by the Certified Court Reporter, testified as follows:

DIRECT EXAMINATION

BY MS. Shirey:

Q Could you, Mr. Newman, state your name and spell your last name for the record.

A My name is Alan Newman, A-L-A-N, last name N-E-W-M-A-N.

Q And where are you working right now?

A I'm employed by the Department of Ecology.

Q And what is your job?

A My job is the senior quality engineer for the program. I do policy work and rule development currently. My

history with the program has been various tasks all the way from being a field inspector and permit writer to writing PSD permits and writing regulations.
Q When you say the program, what program?
A Program being the Department of Ecology's air quality program.
Q And how long have you been part of that program?
A In two separate employment periods, just about 32 years.
Q Could you turn to Exhibit R-2, Ecology's R-2.
A Yes.
Q Do you recognize this document?
A Yes. This is my work history that I've prepared for this and other actions.
Q I just want to hit some of the highlights here. It talks about your education. Could you describe your education.
A I have a bachelor's degree in civil engineering from the University of Washington. I have an associate degree from Olympic College before that. I've been registered since 1983 as a professional engineer in Washington, and I've maintained that registration continuously.
Q When did you first start working with the Department of Ecology?
A I started working at the Department of Ecology in September of 1975 as an EPA employee. I started working

for the Department of Ecology in October of 1976 as an Ecology employee.

Q And have you done air quality work the entire time?

A Almost the entire time. For the period from about 1980 until 1992, I also did water quality permitting, solid waste inspection and permitting and did wastewater construction grants engineering work for the department.

MS. SHIREY: I would ask the board to admit Ecology Exhibit 2.

MR. WISE: Any objections?

MS. BENNETT: No, Your Honor.

MR. WISE: Ecology Exhibit 2 is admitted.

(R-ECY-2 admitted.)

Q (By Ms. Shirey): So in your job as an air quality engineer at Ecology, did you have a formal role in permitting the BP coker heater project?

A I did not have a formal role in the permitting of this facility.

Q Were aware of the coker heater project?

A I was aware of the coker heater project and the permitting actions. The staff working on it sit adjacent to me, and given the nature of our office, it's difficult to be totally shielded from such work.

Q So from time to time, did you answer questions related

to this?
A Yes, I did.
Q So your knowledge of this project is somewhat limited?
A Yes. I would say it's an incomplete knowledge.
Q So I want to turn to the regional haze program that we have heard a little bit about already this morning. What is your role in the regional haze program?
A Currently, I'm working on developing a list of facilities that will be reviewed for four factor analysis and for maintenance establishing reasonable progress goals for the 2021 SIP submittal.
Q That's great. I was actually wanting a more --
A I have been involved doing with the regional haze program specifically, including from before, from about 1995, again, working on regional haze issues related to the Centralia Power Plant's RACT analysis and coordinating that with regional haze requirements for the BART program at that time.
I was involved with working on updates to the state regional haze -- at that point it wasn't regional haze -- but our visibility SIP for '97 and '99.
Q So would you say that you are the lead engineer at Ecology for regional haze?
A Yes. I'm probably the only engineer who works on regional haze.

Q Thank you. So could you give just a general quick description of what the regional haze program is.
A The regional haze program is an outgrowth of the federal Clean Air Act, and it requires states to develop plans to bring the visibility impairment -- it requires the states to develop planning documents, and by rule, in the 1999 regional haze rule, on ten-year increments, those plans are to be developed and updated to bring all of the mandatory federal Class I areas in the United States to a level where there is no anthropogenic impact on visibility.
Q By when?
A And the law does not contain a date. The rule that EPA issued contains the date of 2064 as the date upon which to achieve that goal. The regulations, however, allow states to not have to meet that goal if they can demonstrate to the satisfaction of EPA the rationale to not be able to meet it.
Q But, in general, the goal is to meet the standard of no anthropogenic impacts on visibility at Class I areas by 2064?
A Correct.
Q Are states required to develop plans to meet that goal?
A States are required to develop plans on a ten-year cycle. The first one was actually due nationally in

2007. Due to various delays from the regional planning organizations that assisted the states in doing that work, most of them weren't submitted until 2008 or '9 or, in Washington's case, '10. The next regional haze plan is actually due by rule in July of 2021. The following one is July of 2028 and on a ten-year cycle from there.
Q So I believe you said that Washington did provide a plan?
A Yes, we submitted a plan; it's dated 2010. It may have actually been submitted to EPA in early 2011.
Q So what is the next step after providing that plan?
A The next step after providing the plan is for states to do a five-year review after the plan is submitted on progress towards attaining, in this case, it was our 2018 reasonable progress goals.
Q Could you turn to Ecology Exhibit 8.
A Okay.
Q Do you recognize this document?
A More than I'd like to.
Q What is this document?
A This is Washington's 5-Year Regional Haze Progress Report.
Q And what's the date on it?
A It's September of 2017.

Q Did you write this report?
A I wrote essentially every word of it.
Q So what does it show about visibility in Class I areas in Washington?
A What it shows in general is that visibility in Class I areas in Washington State is improving and has improved at least as much as required to meet our reasonable progress goal for 2018, and this was as of the end of 2014, which is the end of the analysis period, and that in most cases in Class I areas, we exceeded the uniform glide path rate of control.
Q Could you turn to page Roman Numeral IV, I-V. That's the Executive Summary.
A Yes.
Q And could you read the last sentence on the page, last couple sentences.
A The last -- the whole paragraph or the partial paragraph?
Q I am sorry, the partial paragraph.
A "Washington continues to reduce air pollution that produces regional haze. Because of this, visibility is improving in these areas. Overall, the Class I area visibility record shows improvement since the 2000-2004 baseline period. Levels measured in the 2010-2014 period met or exceeded the 2018 visibility goals."

Q Thank you. And then I believe does this document show how the -- or show that, I guess, that the state is meeting its goals?
A Through various graphs that have been developed based on the monitoring data.
Q Could you turn to page 22 of this document.
A Okay.
Q And I want to focus your attention on Table 3.
A Okay.
Q What does Table 3 show?
A Table 3 is a compilation of the Washington State emission inventory. The Washington inventory specifically is the columns headed 2005 and 2011.
Q There are two columns headed WRAP, W-R-A-P. What is that?
A WRAP was the Western Regional Air Partnership. It was the regional group that did develop emission inventories and did the bulk of the dispersion modeling for visibility impacts in all Class I areas in the 13 western states involved in the program. The two dates associated under there, the 2002d inventory, that is a specific inventory that was used to determine the baseline conditions for the modeling purposes. And that was developed for all states based on information. That was what was used, like I said, that was the baseline

modeling.
Q So the baseline modeling --
A Baseline modeling for what is the visibility, modeled visibility impairment, in the baseline period of 2000-2004. So this was using direct decisions and directives from EPA.
Q And where was this impairment?
A Okay, this is just inventory.
Q Oh, this is inventory, this is emission inventory.
A The table is inventory.
Q Thank you. So what does this show for nitrogen oxide?
A What it shows is that stationary source emissions have gone down, area source emissions have gone down and gone down significantly, mobile source emissions have gone down, but they've also gone up as we have more cars. Locomotive emissions have gone down, marine vessel emissions, they have all gone downward.
Q So total, I think on the top of 23.
A Top of page 23, it shows that for 2011, the emissions for 273,791 tons of nitrogen oxide emissions. Comparatively, the inventory for 2005 was 303,964 tons, and the WRAP inventory was even higher at 378,384 tons.
Q So what is the WRAP 2018 number, which is the right-hand column there?
A The WRAP 2018 number was a projection of emissions that

the WRAP modeling group and the emission inventory group developed, principally the emission inventory group developed, in order to predict what the emissions would be in the future from all of these sources in these categories, including the effects of the emission reduction programs, BART requirements, federal rules, and the growth and utilization, the growth of population as they affect emissions. These are the emissions that were used for projecting modeling emission conditions in 2018, which were used in part to define the reasonable progress goals for each Class I area.

Q Would you turn to page 27 in this document, Table 4. So what does Table 4 show?

A Table 4 is a table of the monitored values of the Class I areas and the depiction of what the reasonable progress goal was and the uniform rate of progress target. So the column titled 2000-2004 Baseline, that's what the ambient monitors at the Class I areas that are used to determine visibility impairment in the field, this is what their deciview impacts were at that time. The column 2010-2014 Visibility, it's the next-to-the-last column on the right, that's what the actual calculated visibility impairment for the five-year averages of the worst days, that's this whole table is the worst days, that's the calculated numbers of what was actually measured for that period. And the middle two columns with the goal and the uniform rate of progress are just that.

Q So the baseline, for example, for Olympic National Park was 16.74?

A Yes.

Q And the 2010 to 2014 was 13.82?

A Yes.

Q And on the far right column is the column that says are you meeting the 2018 reasonable progress goals.

A Yes.

Q And what are the answers there?

A And the answer there is yes.

Q For all of the --

A For all of the national -- all of the federal mandatory Class I areas.

MS. SHIREY: I would ask the board to admit Ecology Exhibit 8 into evidence.

MR. WISE: Any objections?

MS. COX: No.

MS. BENNETT: No, Your Honor.

MR. WISE: Ecology Exhibit Number 8 is admitted.

(R-ECY-8 admitted.)

Q (By Ms. Shirey): So as you have heard, the National

Park Service has expressed concerns about adverse impacts from BP's project, well, from BP on national parks, and are you familiar with that or should I point you to an exhibit?
A No, I'm familiar with that.
Q And that the National Park Service actually provided an adverse impact determination?
A Yes.
Q So what does that mean in the regional haze program when you get an adverse determination, adverse impact determination?
A If I considered it the same as an adverse impact determination under 51.302, that means the Washington State Department of Ecology has to evaluate that facility for a SIP update and potential emission reduction requirements. By the rule, that SIP update for this timing is allowed to occur as part of the 2021 regional haze plan.
Q Do you have any tools to ensure that you meet the goals?
A I have the ability -- under the federal Clean Air Act, I have the four factor analysis process, which is used to develop reasonable progress goals for visibility impairment. At the state level, I have the reasonably available control technology process that I can utilize to require emission reduction at a source if I can

define that it meets the criteria to follow that program.

Q Thank you. I want to turn now to AQRV analysis. So in your work at Ecology, have you ever reviewed an AQRV analysis?

A Yes.

Q When, in what context?

A I have reviewed it personally for three permits that I've worked on and I have reviewed it in conjunction with the engineers writing permits that I have overseen as their supervisor.

Q And these are PSD permits?

A These are PSD permits.

Q Any idea how many times you've done that over the years?

A Like I said, three times at least for permits that I personally issued, plus every permit that we have issued from the agency since 1993 through until about -- until Marc Crooks took over the function about five years ago.

Q Are you familiar with the Q/d screening analysis in the FLAG guidance?

A Yes.

Q What is a Q/d analysis?

A It's a screening tool used to -- used by regulators to determine whether a source has significant enough impacts to make it worth the trouble to spend the time to look at it in more detail.

Q So could you turn to Joint Exhibit 11, and it's in one of those two green ones, probably the bigger one.

A Okay. I'm there.

Q So turn to page 18 in this document.

A Okay.

Q So in Section 3.2, Initial Screening Criteria, are you there?

A Yep.

Q And the right-hand column talks about inputs to Q/d analysis. It also talks about how EPA introduced screening criteria in the BART guidelines. Do you see that on the left side on the bottom?

A Yes, I do.

Q And can you describe that a little bit. Are you familiar with that?

A Yeah. And I wasn't reviewing the documents when EPA developed this, but, yes, I'm familiar with its utilization as a screening tool to determine whether their source is worth having -- whether it will have an impact that could be subject to BART.

Q So did you use it in your BART analyses?

A I actually did not use it.

Q And why was that?

A Because my work was focusing on the other criteria that had to be utilized and all of our sources, even if I had used it, they would have failed the test --

Q Okay.

A -- the ones that were subject, ended up being subject to BART.

Q So have you used the Q/d test yourself or --

A I have evaluated Q/d as part of the process of figuring out who the agency will look at for reasonable progress goals for the '21 SIP.

Q Have you looked at Q/d in a PSD context?

A Historically, yes, as has been applied by the Park Service and the Forest Service, to determine whether the source is a large enough source that they wish to expend any resources to review.

Q So can you look at the right-hand column there on page 18 and just tell me what it says about what the inputs to a Q/d analysis are.

A In general, the inputs are the emissions of nitrogen oxide, sulfur dioxide, they extended it to PM10 and sulfuric acid mist. That's the Q. This doesn't actually talk about how Q is calculated other than what's included. And the "d" is the distance of the source from the Class I area in kilometers. Q is in tons.

Q And further down on that column, I think it does talk about --

A Yeah, there at the bottom.

Q So the sentence that starts, "Therefore, the agencies," could you read that?

A Therefore, the Agencies will consider a source locating greater than 50 kilometers from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO2, NOx, PM10 and -- sorry, I'm going to back up -- sulfuric acid mist annual emissions, in tons per year, based on 24-hour maximum allowable emissions, divided by the distance from the Class I area, in kilometers, is 10 or less.

Q Therefore, the agency will consider a source to have negligible --

A To have negligible impacts.

Q Okay. Thank you. In paragraph 22 of Mr. Gebhart's prefiled testimony, he says Q/d is irrelevant for BP's project because the two national parks, North Cascades National Park and Olympic National Park, are already impacted by emissions. Do you agree with that assessment?

A No, I don't. I don't agree with that assessment because the purpose of this is to evaluate impacts from a project, from a new source or from a modification to an existing source. It's not a criteria that you can ignore or should ignore simply because a source already has adverse impacts.

Q Would you turn to, and I have the JE page number, so on the bottom of these, JE1121.

A Okay. That's the graphs.

Q Right. So Figure 1, what does Figure 1 show?

A Figure 1 is a flow chart of what the Park Service says they will use to assess their level of involvement in a new or modified source.

Q And what does it show about Q/d?

A It's a preliminary question and if Q/d is less than or equal to 10, yes, then they have a presumption of no adverse impact.

Q Is there anything in there to indicate that Q/d, there is any limitation to when you would use Q/d?

A No, not that I've ever read in this document.

Q So nothing in this document that might indicate a limit on when to use Q/d?

A Not that I can recall ever having read.

Q Okay. In your experience, have Q/d analyses been used to screen out projects from other facilities that already impact Class I areas?

A Yes.

Q So moving on from Q/d, for the visibility portion of the AQRV analysis in this case, BP determined the net

emissions increases from the coker heater project by looking only at short-term emission increases. Is that the correct way to do it in your opinion?
A Yes.
Q And why is that?
A Because that's the only new emissions, the only new allowable emissions that will come under this project.
Q And I neglected -- well, yeah, for the visibility portion of the AQRV analysis?
A For visibility.
Q What is it about visibility that --
A Because it would be looking at the change in 24-hour impacts for the input to this modeling to determine whether or not it's a significant change.
Q So is there something about visibility that would point you to looking at 24-hour emissions?
A Nothing specific, other than convention is you look for -- for regional haze purposes, at least, visibility is analyzed on a 24-hour emission impact basis, it's not looked at on an hourly rate basis or an annual rate, just -- I can keep going.
Q So the visibility looks at short-term emissions because visibility itself --
A Short-term emissions would be under 24 hours duration. Twenty-four-hour emissions are 24-hour emissions.

Long-term emissions would be longer than a 24-hour period and going all the way up to annual emissions.
Q So why would you use 24-hour emissions when evaluating visibility impacts?
A As a supposition, one answer is that that's the time period upon which the ambient monitoring data that's used to characterize visibility is collected. It's a 24-hour integrated sample and, therefore, it's difficult to say what a one-hour rate would go and then give you an answer there.
Q Would you look at annual emissions in order to evaluate visibility impacts?
A No.
Q Why not?
A Because annual emissions, at best, would depict an average condition, and average is not what we look at in visibility.
Q So in BP's case, because they looked at just the short-term emission increases, it means they only looked at emission increases from the coker heaters because those are the only emission units that will have short-term emission increases that will be caused by the project?
A That's my understanding.
Q And is that the correct way to do it?

A That's how I would do it. That's what I understand is the correct way to do it.

Q So the project will cause annual increases in emissions from some other emission units at the facility because those other units will run more days, or will run more on some days than they currently do. Should the increased annual emissions from those other emission units be included in the visibility impacts?

A No.

Q And why not?

A I have no evidence from my limited review that they actually change the 24-hour emission rate from the facility or from these units that run just more hours of the day.

Q So in his testimony on Monday, Mr. Gebhart said that under the FLAG guidance, a modified unit is the same as an affected unit. Does that make sense to you?

A No, it doesn't, because a modified unit has to meet the definitional criteria to be modified.

MS. BENNETT: Objection. That's a mischaracterization of Mr. Gebhart's testimony. He stated that that, one, FLAG does not provide a description of an affected or modified unit, and he did not say that they are the same, he said that there is no description, and so that is not a correct statement that you are masquerading as Mr. Gebhart's testimony.

MR. WISE: Ms. Shirey, any response?

MS. SHIREY: I can say that's what I wrote in my notes and that's what I understood him to say was that basically under FLAG, the two are treated the same way.

MS. BENNETT: That's a different --

MR. WISE: Why don't you just ask Mr. Newman his opinion on that.

Q (By Ms. Shirey): So what is your opinion on modified units and affected units under FLAG, are they treated the same or not?

A For visibility analysis, my personal opinion, they should not be treated the same.

Q Thank you. So I want to turn to -- I think I want to go now to the BACT analysis questions. In your career, have you done BACT analyses for PSD permits?

A Yes.

Q Any idea how many?

A Like I said, I've done three personally and I have overseen probably another 15, 18 over the years.

Q When you do a BACT analysis, do you review the cost effectiveness analysis?

A Yes.

Q And when you're looking at a cost effectiveness

analysis, do you look at the costs to see if they look reasonable?
A Yes.
Q Have you ever gone back to an applicant and questioned the costs?
A Yes.
Q So you really are looking to see -- so you have found costs on occasion that looked excessive to you?
A Yes.
Q And gone back to the applicant?
A Gone back to the applicant, challenged the applicant and they've changed, or we changed it for them.
Q So in this case, Ecology rejected selective catalytic reduction as BACT for the coker heaters in the BP project as not cost effective.
A That's my understanding.
Q So in paragraph 34 of his prefiled testimony, Dr. Sahu says Ecology should have looked harder at the costs borne by other facilities that have installed selective catalytic reduction to control emissions from coker heaters. What does a permitting authority need to consider when other facilities have installed a particular emission control technology as BACT?
A If it's installed as BACT, then we have to look at what did it cost them in a cost effectiveness, what did that

state decide this source could bear as a reasonable cost, how that relates to other costs that have been borne by other people installing the control, knowing that the cost of installation of a particular emission control will vary between types of sources and even between emission units within a given source.

Q So you do look at costs at other facilities --

A Yes.

Q -- when an emissions control technology has been required as BACT at another source.

A (Nods head affirmatively).

Q Might a facility employ a particular control technology if not required to use it as BACT?

A Yes.

Q Why?

A In some cases, and I know very well, that people will install a control simply to avoid the time and process overhead of the PSD permitting process.

Q Any other reasons?

A Sometimes they will do it to avoid having to go through non-attainment new source review.

Q Okay. And I imagine there are other reasons.

A Each company has a whole variety of reasons why they might choose to do something that might not -- that their competitor might think is not in my best business interest for you to do that.

Q So in paragraph 41 of Dr. Sahu's prefiled testimony, he says the use of selective catalytic reduction to avoid PSD carries with it the presumption that SCR is cost effective. Do you agree with that?

A No.

Q Why not?

A Why not? As I said, it carries forward the presumption that the company involved decided that the cost of installing SCR was less expensive and less trouble than going through the permitting process that they would otherwise have to go through. So just the overhead of the PSD permitting process often causes people to put on emission controls simply to avoid the delays of the process.

Q So in paragraph 45 of his prefiled testimony, Dr. Sahu states that avoiding BACT particularly is the major reason sources try to avoid PSD. Do you agree with that?

A No.

Q Why not?

A In my experience, people avoid PSD to avoid the process and the time and cost of the PSD process itself, not necessarily to avoid installing BACT. Under Washington State law, they still have to install BACT because the control that they would install as a non-PSD source, modification or new source, still is required to meet BACT, meeting the same definition as the federal one.

Q So I think what you're saying is that in Washington State, minor sources that are not major for PSD still have to use BACT, is that --

A That is correct.

Q And are there still sources in Washington that try to avoid PSD?

A Yeah.

Q Okay. So in paragraph 47 of his prefiled testimony, Dr. Sahu says BP must have found the use of SCR, selective catalytic reduction, on the coker heaters at its Whiting facility cost effective even though it's required in the consent decree. Do you agree with that?

A I do not agree with that.

Q And why not?

A In the context of a consent decree with EPA, it's also an enforcement action, and my experience with EPA in enforcement actions and consent decrees is cost effectiveness has nothing to do with what gets put into it. It's more like what extortion can EPA get out of the source to reduce emissions.

Q All right.

A Sorry. Sometimes I can be blunt.

Q In paragraph 48 of his prefiled testimony, Dr. Sahu says you still need to look at costs at facilities that installed SCR to meet LAER requirements, and what it LAER?
A LAER is lowest achievable emission rate.  It's required of new emission units and modified emission units that exist in non-attainment areas and applies to the pollutant or pollutants for which there is non-attainment.
Q So do you agree that in evaluating BACT and looking at other sources, you need to look at costs at facilities that install SCR as LAER?
A I have found, except for California, you can't find cost effectiveness information for LAER installations.
Q So have you found cost effectiveness --
A Only in California, because they have it in their clearing house as part of the information.  In California, LAER is called BACT and it's a creature of California state law.
Q And now I'm confused.
A Okay, sorry.  So it is possible to find information on LAER cost effectiveness; however, it's not used in the decision of a LAER emission limit or whether a control is appropriately or to be installed under LAER.
Q So if I understand what's going on in California, they

use a standard in attainment areas that they call BACT, but it really is LAER?

A Yes. They also use the same standard in their non-attainment areas.

Q Right.

A And definitionally, it's identical to EPA's definition of LAER.

Q And so when you're looking for LAER determinations in California for facilities in non-attainment areas, would you expect to find a cost effectiveness --

A I would expect to find a cost analysis. California air districts do have cost effectiveness analysis and information.

Q Okay, but not for other states?

A Not other states.

Q Okay. So what does a permitting authority need to consider when other facilities have used an emission control technology but for purposes other than BACT?

A Repeat that, please.

Q If you're looking at a particular technology and you're considering whether to require it as BACT in a particular permit application, and you want to look at other facilities, but the other facilities that you are looking at didn't require it as BACT, they may have used SCR, but they didn't require it as BACT, what do you

need to look at at those facilities?
A Well, first off, their use of the control makes it an available control so it meets the step 1 criteria of being an available control under the BACT process. You may make phone calls to the local authority to see if there is information on costs that may have been provided. My experience has found it's probably not there. It does show up at -- certain agencies will have it, it will have been provided by the company for some reason.
Q Does EPA's 1990 BACT guidance provide anything on this?
A I believe so, but my memory is not exactly fresh on it.
Q Could you turn to Joint Exhibit 12.
A Okay. What page?
Q Page B.45.
A All right.
MS. SHIREY: And for the board, that has a JE number if you would like, but if you're all there --
MS. MARCHIORO: Please.
MS. SHIREY: JE001343.
Q (By Ms. Shirey): So I think starting the second line of page B.45, could you read that first sentence.
A "This may occur, for example, where a control alternative has not been required as (BACT or its

application as BACT has been extremely limited) and there is a clear demarcation between recent BACT control costs in that source category and the control costs for sources in that source category which have been driven by other constraining factors (e.g., need to meet a PSD increment or NAAQS)."
Q And what is a NAAQS?
A National ambient air quality standard.
Q And are sources required to meet the national ambient air quality standards?
A All sources or emissions have to meet the national ambient -- cannot cause or contribute to an exceedance of a national ambient air quality standard.
Q In the next paragraph, can you find the sentence that begins "Specifically."
A Yes.
Q Could you read that?
A "Specifically, the applicant should document that the cost to the applicant of the control alternative is significantly beyond the range of recent costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant."
Q So what this is saying, I believe, is that if you're looking at a technology that has not been required as BACT or has rarely been required as BACT, in a similar

situation, you look at whether the cost of the technology is beyond the range of recent costs normally associated --

MS. BENNETT: Objection. Leading. She can ask what his opinion is.

MS. SHIREY: I'm just trying to summarize what he's just read.

MS. BENNETT: You can summarize what his opinion is of what he just read, but not what he just read; summarize his understanding.

MR. WISE: Ms. Shirey, just think about your questions and try to avoid leading if you can.

MS. SHIREY: Okay. I was just trying to kind of condense down those two pieces.

Q (By Ms. Shirey): So what is your understanding of what this guidance says about what to look at if a technology has not been used as BACT or has rarely been required as BACT?

A It allows you to be a little more thoughtful in whether or not this is an appropriate control technology. You might want to do a little additional analysis than you would otherwise do on a commonly utilized control.

Q Specifically, what are you supposed to look for in costs, in the question of cost?

A Compare what costs that other people have borne, other sources have borne in installing either this control that you're looking at or controls in general.
Q So you're looking at controls that have been used associated with BACT?
A Yeah, BACT controls, it could have been RACT analysis. They do exist. If you have information on a LAER installation, it could have been the cost that other sources incurred there.
Q So I believe it does say something about looking at the range of recent costs. Do you see that?
A Yes.
Q Normally associated with BACT?
A That's correct.
Q So do you know what the range of recent costs normally associated with BACT for nitrogen oxides is at Ecology?
A I know how it's migrated over the years. Today's value, I'd have to ask Mr. Crooks what we quote out.
Q I wonder if you could look at Ecology's Exhibit 9.
A Okay.
Q So do you recognize this document?
A I recognize this document.
Q Can you describe it?
A It's a compilation of recent NOx determinations done in Washington State. Principally, most of these have to do

with reciprocating engine installations.
Q So are these recent BACT determinations in Washington for NOx?
A These all date between 2011 and 2017.
Q Do you know who all helped prepare this document?
A I believe Mr. Huitsing compiled this page.
Q Okay. Do you know if he got help from anybody else at Ecology?
A No, I don't.
Q Okay. So what does page 1 show? You just were discussing it.
A Page 1 shows seven different facilities with technologies and the type of source -- a little information about what the type of source that was being looked at and the cost-per-ton analysis that came out of those, and whether or not that was accepted or rejected as BACT.
Q Do you know if this document shows all of the NOx BACT determinations for PSD projects in the past five years?
A I believe this is all of them that I am aware of in the last five years.
Q And then does it also show some other non-PSD sources?
A I believe the data centers are all non-PSD.
Q Okay. So what does the document show about costs that have been rejected for BACT for nitrogen oxides?

A That we have been rejecting costs that were as low as $11,600 as not cost effective for NOx.
Q And what does it show about costs that have been accepted?
A It shows we have no -- it doesn't have any information about costs that have been accepted. The table, the technologies all indicate these were the base capabilities of the emitting unit that was subject to permit.
Q So you may have already started answering my next question is why don't the technologies that were accepted have cost analyses associated with them?
A Because these were all what was proposed to be installed to meet standards, at the very least, meet NAAQS and Washington State Toxic Air Pollutant Standards.
Q So they were not required to do a cost analysis?
A No, no.
Q In paragraph 56 of his prefiled testimony, Dr. Sahu claims that EPA has considered $10,000 per ton to be acceptable cost for BACT since at least 2001. Does that mean that costs for BACT in Washington should have been $10,000 per ton since 2001?
A No, it doesn't, and there's context around that $10,000 value that's important to consider.
Q Tell me.

A The context is that number comes from a document of what EPA thought would be recommendation to states as they were reviewing PSD applications for facilities having -- oil refineries having to upgrade their facilities to meet tier 2 gasoline standards or further higher levels of gasoline sulfur-removal requirements.
Q And why is that important?
A It's important because it was EPA looking at it from a national scope, from their office in North Carolina, and it doesn't consider anything with local costs or local effects on sources.
Q So do states have different BACT thresholds than EPA?
A Yes. Local agencies can have different thresholds than the state's.
Q Could you turn to Ecology Exhibit 23?
A Okay.
Q Do you recognize this document?
A Yes, I do.
Q Can you just briefly say what it is.
A It's a letter that was written by EPA Region 8 to Mr. O'Clare of North Dakota related to some costs effectiveness analyses done by the state at the Milton Young Power Plant.
Q Could you turn to page 5 and 6.
A Starts on page 4.

Q Okay. So on the bottom of page 4, I believe it talks about -- what does that last bullet say?
A The last bullet is the reference to the EPA guidance that I mentioned earlier, the 2001 guidance on the low sulfur gasoline regulation.
Q That used the $10,000-per-ton cost effectiveness threshold?
A That's correct.
Q Okay. So on page 5, does it talk about state thresholds for BACT?
A There is some states that have numbers listed in here. California Air District's are listed as having cost effectiveness of 97 to $24,500 a ton. There is an air waste management meeting paper from 2002 which talks about Connecticut having a cost of $9,000. At the same time, Arkansas was a $5100 and Michigan was $22,000.
Q The second bullet point on that page, what does it say?
A And that has Nebraska, Utah, Alabama, Oklahoma each have stated costs below $5,000 per ton will be presumed cost effective.
Q So does EPA acknowledge here that states can have different cost effectiveness thresholds?
A Yes. They have to be acknowledging that because they're just showing how all of these various numbers exist in people's different states.

Q So turning back to Ecology Exhibit 9.
A Okay.
Q Turn to page 2 of that document. What does this show?
A And this shows cost thresholds that we have used at Ecology over the years.
Q Can you just run down those quickly.
A So in the '80s up through the early '90s, we used a threshold of $2,000 a ton.
Q So I want to stop you for a minute then. What did that apply to?
A And that applied to pretty much any BACT decision, major or minor, PSD or otherwise.
Q What pollutants?
A This was the number that was in place when I started and the staff applied it to all pollutants.
Q Including toxic pollutants?
A They did not apply it to toxic air pollutants because the air pollutant rule didn't exist until late '80s.
Q Okay. But it applied to all criteria pollutants?
A All the criteria pollutants, all the PSD-regulated pollutants at that time.
Q And I will just ask you what the criteria pollutants are for the benefit of the board.
A Criteria pollutants are -- the 1980 version or the today version?

Q Why don't we go with the today version.
A Okay. It's PM2.5, PM10, ozone, NOx, sulfur oxides, lead, and ozone.
Q You said ozone twice?
A Did I say it twice? There's six of them.
Q And what's the sixth? I always forget one, too. It's not fair. I can tell you what it is. Can I tell him what it is? The sixth one is carbon monoxide.
A Oh, well, that's because nobody cares anymore.
Q So going back to Ecology's Exhibit 9, what it shows on page 2, so 1980s, the cost was about $2,000 a ton?
A Yes.
Q And then what after that?
A Then after I started managing the program, we started growing the costs and reflecting what costs were being imposed by other states for RACT for PSD permitting purposes, and in that process, we were starting to see, as reflected in EPA's guidance, that there were differences both between pollutant and between the type of source emitting the pollutant on what was cost effective.
Q And so what were --
A So in the mid '90s we had $7,000 was the cost effectiveness for our CR applied to a gas combustion turbine, but it was less than $1,000 if it was SO2 for

an oil-fired boiler with heavy oil.
Q So there was a variety --
A A variety.
Q Okay. Was $7,000 per ton about the top?
A That was as expensive as we got. We discussed at various times what might be appropriate for toxic air pollutants, but we never even established even a rule of thumb.
Q So then the last discussion here is the costs that are considered acceptable now. What does that say?
A And that just says if a project comes in today, and this is what I would defer to Mr. Crooks on, costs below $5,000, you know, don't even ask, just do it. Costs between 5 and $10,000, we'll start getting our pencil out to see if there are errors in the analysis, especially the cost analysis or the tons removed analysis. And if it's over $10,000, then it's not considered a reasonable cost. And even that, those are probably not fixed numbers. They're probably -- if it's close to -- if it's 10,100, I would recommend getting your pencil out.
MR. WISE: Ms. Shirey, we're coming up on the noon hour. How much longer do you have on direct?
MS. SHIREY: I have a bit longer, but

I can finish this particular thing up pretty quickly.

MR. WISE: Okay. When you reach a stopping point.

Q (By Ms. Shirey): So in paragraph 57 of his prefiled testimony, Dr. Sahu claims that if $10,000 per ton was the proper threshold in 2001, inflation would bring that up to $14,000 per ton, so $14,000 per ton is the proper cost threshold for BACT now. So do you agree that $14,000 per ton should be considered cost effectiveness threshold for BACT in Washington now?

A Not in Washington. Might be someplace.

Q All right. So Dr. Sahu in his prefiled testimony used a formula to update the EPA's cost effectiveness value of $10,000 per ton to $14,000 per ton. That would have been paragraph 57. Does Ecology Exhibit 9, page 2, have anything to say about that?

A Yeah, it actually has that calculation shown for the $7,000 value using the same approach that he had in his prefiled testimony.

Q So when you say the $7,000 value, what is that?

A The $7,000 value from the 1990s to mid 2000s that Ecology would have used as a top end.

Q And so if you adjust that value for inflation, what do you come up with?

A Using the Engineering Compliance Cost Index isn't exactly an inflation adjustment, but it reflects the change in the cost of materials and construction at a construction project of the nature of adding a boiler or SCR costs, but, yes, it says that that number would come up to just over $10,000 per ton removed.

MS. SHIREY: Okay. And that's a reasonable stopping place for us right now.

MR. WISE: Okay. Why don't we take a lunch break and come back at one o'clock and we'll finish up this direct.

(Recess from 12:00 p.m. to 1:00 p.m.)

MR. WISE: Do you want to continue with Mr. Newman's direct?

MS. SHIREY: Yes. And the first thing I would like to do is ask the board to admit Ecology Exhibit 9 and Ecology Exhibit 23, which I referred to a little bit ago.

MR. WISE: Nine and 23. Any objections?

MS. BENNETT: No, Your Honor.

MR. WISE: Thank you. Ecology Exhibits 9 and 23 are admitted.

(R-ECY-9 & R-ECY-23 admitted.)

Q (By Ms. Shirey): We left off with cost thresholds. So now I would like to turn to another aspect of a BACT cost effectiveness analysis, which is the interest rate that a facility would use.

In paragraph 76 of his prefiled testimony, Dr. Sahu claims the proper interest rate BP should have used for BACT effectiveness is the actual interest rate BP paid. Do you agree with that?

A No.

Q And why not?

A The cost effectiveness analyses, in my history and training, has been to use a uniform 7 percent interest rate for all projects.

Q And who trained you to do that?

A I was trained to do that by Region 10 permitting staff.

Q Region 10?

A EPA Region 10 permitting staff who did the PSD permits and who we worked for as a delegated agency.

Q I am going to hand you a copy Dr. Sahu's prefiled testimony, if I may. Would you turn to page 35, paragraph 76.

A Okay.

Q Do you see where he talks about the interest rate to use?

A Yes.

Q And he cites to a footnote; is that right?

A Yes, Footnote 33.

Q Would you read Footnote 33.
A "For example, in Chapter 2 of its Control Cost Manual, EPA states that: 2.5.2 Interest Rates. Firms may borrow to finance the expenses associated with their compliance strategies. The interest rate at which a firm borrows is a key component in estimating the total costs of compliance. Financial markets set different interest rates for different activities depending on many factors. Because this manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate which is the rate firms actually face. For permit applications, if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates."
Q Thank you. Could you turn to Ecology Exhibit 19.
A Okay.
Q So what is this document?
A This appears to be a copy of all or part of, probably part of, the cost estimating section in Chapter 2 of Section 1 of EPA's Seventh Edition of the Cost Estimating Manual.
Q Could you turn to pages 14 and 15 in this document.
A Yes.
Q So the bottom of page 14 has a section on interest

rates. Could you read the first sentence there.
A First sentence under 2.5.2 reads, "Firms may borrow to finance the expenses associated with their compliance strategies."
Q And on the next page, do you see in the middle of the page where there is a formula that says "i" equals "ir" plus "p" to the "e"?
A Yes.
Q In the paragraph below that, could you read that little short paragraph.
A "When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face. Accounting for inflation should be done separately rather than using the real interest rate."
Q Thank you. So with that in mind, could you go back to Dr. Sahu's prefiled testimony, Footnote 33.
A Yes.
Q So the language you just read, is that the quoted language in Footnote 33?
A There is an ellipsis in the middle of the quotation, which I'm not sure where -- it connects to something which is outside of what I just read.

Q Right, but the words that are there --
A Up through the ellipsis.
Q Okay.
A The second ellipsis in the paragraph.
MS. BENNETT: Objection. Dr. Sahu's testimony can stand for itself.
MS. SHIREY: Dr. Sahu, when I asked him where this came from, this quote in the cost manual in his prefiled testimony, he wasn't able to tell me where it came from, and I'm trying to establish where it comes from.
MR. WISE: Objection overruled.
Q (By Ms. Shirey): So when I asked Dr. Sahu if this was the document he was quoting from, this Chapter 2 that you just quoted from, he said it might have been, but that the language might also have come from the Sixth Edition of EPA's Cost Manual, and so I wonder if you could turn to Ecology Exhibit 15.
A Okay.
Q So what is this document?
A First page is the cover sheet for the Sixth Edition of the Control Cost Manual by EPA.
Q EPA's Air Pollution Control Cost Manual?
A Yes.
Q What's the date?

A January 2002.
Q So do you know if this document contains the language in Dr. Sahu's Footnote 33?
A It does not.
Q Thank you.
MS. SHIREY: I would ask the board to admit Ecology Exhibit 19 and Exhibit 15 into evidence.
MR. WISE: Any objections?
MS. BENNETT: No, Your Honor.
MR. WISE: Ecology Exhibits 19 and 15 are admitted.
(R-ECY-19 & R-ECY-15 admitted.)
Q (By Ms. Shirey): Would you turn to in Ecology Exhibit 15 to page 2-13.
A Okay.
Q And in the middle of the page, the last sentence of the first full paragraph, could you read what that says about interest rates.
A This is the last sentence of the first full paragraph. "Also, since a change in the general level of prices affects everyone simultaneously, social rates of interest do not account for inflation. OMB sets the social interest rate for governmental analyses, and it is currently set at seven percent."
Q And then in the next paragraph, I think it's the third

line down, starts with "However."

A Okay. "However, the social rate of interest is probably not appropriate for industry."

Q Thank you. So is this second sentence about the social rate, which at this point was 7 percent, not appropriate for industry, is that consistent with your experience in what you've been taught about what interest rate to use?

A No, it is not consistent with my instructions and training.

Q So what have you been taught?

A What I've been taught is to use a 7 percent interest rate as not just a default but as the rate to do cost effectiveness analyses.

Q Why is that?

A It allows inter-comparability between different sources on the same controls. And it does not allow a source to skew a cost effectiveness analysis by using different emission rates as their cost of money.

Q So what happens if the interest rate at the source that the applicant has, their actual interest rate is higher than 7 percent?

A We have said to use 7 percent. In fact, if they were to use 7 percent, it would raise all of their costs and make what otherwise might be a cost effective control non-cost effective.

Q You mean if they use --
A Use a higher interest rate.
Q So the approach that Dr. Sahu cites to in the latest EPA guidance, does this represent a new guidance to you?
A Yes, it does.
Q Do you know why EPA is changing its approach?
A No. I did not read any background documents that would tell me why they made the change.
Q Can you outline any problems that could occur with this approach?
A Well, the largest problem is that you can't compare the cost of the control on the same emission unit between different companies or even the -- it's different facilities owned by the same company that are in different states.
Q So I want to turn back to Ecology Exhibit 19. What is the date on this document?
A November 2017.
Q The permit for the coker heater project was issued on May 23, 2017. Would this new guidance have applied to that document?
A It wouldn't have been final chapter or guidance at that time.
Q So would it have applied?
A Would not have applied.

Q The next issue I want to touch on is the contingency factor that BP used in its cost effectiveness analysis. Are you familiar with contingency factor?

A Yes, I am.

Q So BP used a contingency factor for BACT for both nitrogen oxide and $SO_2$, they used a project contingency factor of 15 percent. In paragraph 78 of his prefiled testimony, Dr. Sahu says the contingency factor should have been more like 5 percent. Do you agree?

A No, I don't agree for the level of the estimate, the quality of the estimate that I believe was actually prepared for the project.

Q So can you talk about the estimating process and what contingency factors make sense?

A So estimates are done at various points during the development of a project. They range from nearly order of magnitude costs as a company starts evaluating the project, and then there is a planning level cost that is says this is what we want to do and this is what the parts are. That might be as accurate as plus or minus 50 percent. And then as you move towards getting authorizations, you get better quality estimates. By the time you actually are embarking on design, you've got an estimate that might be accurate to 20 to 30 percent. That's the point at which you're now preparing construction drawings and everything. And then when you get at the end of construction drawings, the engineer firm doing that work might get to an accuracy of as close as 5 or 10 percent.

So that's all reflecting the quality of the information that's been acquired, the knowledge of material needs, the knowledge of sub foundation requirements. In the air pollution world, it's the knowledge of what will actually be my BACT emission requirements and what are the limits and what does that equipment actually entail.

Q So when a facility submits a permit application with a BACT determination, at what stage in that process is that; how far along in the estimating process is that?

A I characterize it and have had it characterized to me is it's that zone between I'm done with the planning, I've got approval, but I'm not yet into formal design. So it's probably plus or minus 30 percent.

Q And BP used 15 percent, so was that reasonable in this case?

A Fifteen percent is not an unreasonable contingency to cover unknowns, which can include the actual cost of materials when you actually go to bid.

Q Does EPA have any guidance on contingency factors?

A I don't remember reading any. They may have it; I don't

remember reading any.
Q Okay. I want to go to Ecology Exhibit 15 again.
A Okay.
Q This is EPA's Sixth Edition of its Cost Control Manual. Turn to page 2-44.
A Okay.
Q Table 2.5, what is that table?
A Table 2.5 looks like a short version of an example cost analysis for determining total capital investment.
Q And what is the technology being talked about here?
A The particular technology is SCR.
Q And what does this have for project contingency?
A And this uses a project contingency of 15 percent.
Q Do you know what project contingency is?
A Project contingency is all of the variables related to getting the project built, like I said, sub foundation, sub soil issues, overhead infringements that you don't understand before you get into design, and the cost of raw material to build it is going to vary over time.
Q Could you turn to Exhibit R-24. It's in BP's binder.
A Twenty-four?
Q Twenty-four.
A Okay.
Q Do you recognize this document?
A Yeah, this is the May 2016 version of the SCR chapter

from the Control Cost Manual.
Q So is this the same Control Cost Manual that we've been looking at?
A This is the May 16th version of the Seventh Edition version of this chapter.
Q Okay. And this chapter deals specifically with selective catalytic reduction?
A That's correct.
Q Could you turn to page 2-64.
A Okay.
Q And the Section 2.4.1, talking about total capital investment. Could you read the last sentence of that first paragraph?
A So this the first paragraph under 2.4.1, the last sentence. "The capital cost equations included in the manual reflect a process contingency of 5 to 10 percent and a project contingency of 15 percent."
Q Can you tell me what process contingency is?
A My always understanding of process contingency is it's the risk of the process to achieve its design requirements. So SCR being a relatively mature technology, the risk of it failing to meet a design requirement is fairly low.
Q I want to move on to change in a method of operation and when that is a modification and when it's not.

So the new coker heaters that BP is installing will be able to run longer between cleaning, which means the downstream units that burn coker off-gas will be able to run longer over the course of a year. You following that?

A (Nods head affirmatively).

Q NPCA claims the increased emissions from the downstream units made possible by the new coker heaters makes those downstream units modified units subject to BACT. Do you agree?

A No, I don't.

Q Why not?

A Those downstream units already are capable of burning that fuel stream and have been permitted to use that fuel stream in the past from the existing cokers.

Q Could you turn to Exhibit P-11. So that's in the smaller of those green books.

MS. BENNETT: Objection, Your Honor. Mr. Newman already testified to the fact that he does not have personal knowledge of the permit, he hasn't worked on the permit, so this line of questioning we should not be going down.

MR. WISE: Ms. Shirey.

MS. SHIREY: I'm asking Mr. Newman, as someone who has extensive experience in PSD permitting, whether certain explained decisions or explained pathways in the permit are consistent with his experience.

MR. WISE: Objection overruled. I'll allow the question.

Q (By Ms. Shirey): So Exhibit P-11, do you recognize this document?

A Yes, I do.

Q What is this?

A This is an EPA guidance letter related to a project at the Puget Sound Refinery in Washington State.

Q Which Puget Sound refinery?

A That's the name of the refinery actually, but it's currently owned by Shell.

Q Okay. So do you know what project this is talking about?

A This was an old project that added a new delayed coker unit to the facility.

Q And when was that project?

A According to the first paragraph of the letter, that was 1983.

Q And what happened in 1983?

A In 1983, they built a brand-new never existing delayed coker unit and then routed the off-gasses of that to the flare system header.

Q EPA's decision on that question is at the bottom of page 2 of this document in the second and third sentences of the last paragraph. Could you read those two sentences?
A "Under NSPS subpart J, it is the agency's position that a physical change made at an upstream refinery process unit could result in an operational change to the flare as a result of additional fuel gas being released to the flare. Combusting gas streams not previously combusted in the flare is a change in how the flare operates whether these streams are routed on a routine or on an intermittent basis."
Q Okay. Now I'm wondering if you could turn to Ecology Exhibit R-20.
A R-20. Okay.
Q Do you recognize this document?
A Yes. It's operating permit statement of basis for Shell Puget Sound Refinery.
Q And if you turn to page 51 in this document.
A Yes.
Q It describes the construction history and regulatory applicability, I believe.
A Yes, it does.
Q And what does that first paragraph say?
A You want me to read it?
Q Well, if you could just state it.

A "Shortly, the delayed coking unit was constructed in 1984 under a Northwest Clean Air-issued permit that was issued in 1983. It was revised at a later date."

Q So is this the project that was being discussed in EPA's guidance letter that we just read?

A I believe this is the same project.

Q Okay. Is this similar to what's going on at, as far as you know, as what's going on at the BP facility?

A No.

Q And why not?

A This was a brand-new coker unit at a facility that had not had a coker unit before.

MS. SHIREY: I would ask the board to admit Ecology Exhibit 20.

MR. WISE: Any objections?

MS. BENNETT: No, Your Honor.

MR. WISE: Ecology Exhibit Number 20 is admitted.

(R-ECY-20 admitted.)

Q (By Ms. Shirey): I wonder if you could turn to Exhibit 22, Ecology Exhibit 22.

A Okay.

Q Do you recognize this document?

A Yes, I do.

Q What is it?

A It's an EPA guidance letter from EPA headquarters to EPA Region 10 regarding a PSD permit applicability question for a pulp mill in Washington State.

Q Do you know what that project entailed?

A Yeah, it -- let me read this. The company was proposing to install a pulp-bleaching plant and a larger digester for the mill.

Q And what kind of emissions increase would that cause?

A It could cause carbon monoxide emissions, it could cause emission increases at the recovery furnace from getting more black liquor.

Q Recovery furnace?

A Yeah, recovery furnace, recovery boiler.

Q Okay. So I wonder if you could read the third sentence in that first paragraph.

A "While the construction of these units does not by itself cause increased emissions, emissions from the recovery boiler as a result of this construction activity will increase above the significance levels but remain below the maximum design permit levels."

Q And EPA's decision on this particular question was -- that is the next-to-the-last paragraph on page 3 of this document. What did EPA decide here?

A EPA concluded "Since the recovery boiler will not be undergoing a physical change or change in the method of operation, it will not have to apply BACT. However, the emission increases have to go through air quality analyses and will consume air quality increments."

Q Could you -- if you don't know, say I don't know, but if you do know, could you describe how the situation in this letter is similar to the situation with the BP coker units?

A Based on the information I've heard here and in my discussions with the permitting staff, this looks exactly like the project in regards to what we call affected units in this permit.

Q And why is that?

A Because the units are only increasing their utilization potentially or increasing an existing fuel; they're not being physically modified or operationally modified.

Q Could you turn back to 22 for just a second. What is the date on Exhibit 22?

A The date on Exhibit 22 is July 28, 1983.

Q Okay. So now go back to Exhibit 21. And what is the date on that document?

A February 8, 2000.

Q So do you know what this letter is, what this document is?

A This is another letter asking about dealing with PSD applicability for the bottleneck sources and has a

number of scenarios they're investigating.
Q So if you turn to the second page of this document, there is an indented quoted paragraph in the middle of that page. Do you see that?
A Yes.
Q Do you know where that paragraph came from?
A The text just ahead of it says it came from the 1983 letter from EPA Headquarters to Michael Johnson of EPA Region 10 that's referenced in 22.
Q That is the one, that Ecology Exhibit 22.
A Yes.
Q And can you read the first sentence of that quoted piece.
A "Since the recovery boiler could not have operated at a level higher than that provided by the existing digester capacity, any increase in actual emissions at the recovery boiler, which will result from the increased capacity provided by the larger digester, must be considered for the purposes of PSD applicability."
Q And then go on.
A "Since the recovery boiler itself will not be undergoing a physical change or change in the method of operation, it will not have to apply best available control technology."
Q Thank you.

MS. SHIREY: I would ask to admit Ecology Exhibits 21 and 22.

MR. WISE: Any objection?

MS. BENNETT: Your Honor, I object to Exhibit 22.

MR. WISE: What's your objection to 22?

MS. BENNETT: It lacks foundation. It appears that Mr. Newman has not had the level of familiarity with this document and actually has been reading this document while he is on the stand.

Q (By Ms. Shirey): So I would ask, Mr. Newman, are you familiar with this document?

A I have seen it before and read it before.

Q You've read it before. Thank you.

MR. WISE: Mr. Newman is an expert and he's been presented with facts and asked for his opinion. I don't have any problem with that. So I'll overrule the objection.

MS. SHIREY: So I ask to admit Ecology Exhibits 21 and 22.

MR. WISE: Ecology Exhibits 21 and 22 are admitted.

(R-ECY-21 & R-ECY-22 admitted.)

Q (By Ms. Shirey): So I have one last or couple of

questions. There's been some discussion in this case about affected units versus modified units. Can you describe what these two terms mean?
A Well, modified unit is, definitionally, it's an emission unit that's physically or operationally modified that results in emissions increase as a result of an operational modification.
An affected unit, which also can go by the term debottleneck, is an emission unit that has an emission increase as the result of another project but for which it is not modified or has a change in its method of operation.
Q Is that an important distinction in air permitting?
A It is a very important distinction in air permitting. It helps define what emission units are subject to BACT and which ones are simply subject to ambient air quality analysis.
Q Thank you. I have no further questions.
MR. WISE: Okay. Ms. Bennett, cross exam? I'm sorry, any more direct questions?
MS. POWER: No, thank you.

CROSS EXAMINATION

BY MS. BENNETT:
Q Good afternoon, Mr. Newman.

A Hello.
Q You testified that you're familiar with FLAG guidance, correct?
A I've used FLAG guidance and read it over the years.
Q And you say you have familiarity with this project?
A I have a rudimentary familiarity with the project from my proximity to the permitting staff and having been asked questions over time.
Q Given that rudimentary familiarity that you're stating, isn't it correct that Ecology has not received any formal communication from the Park Service or the Department of Interior after the finding of adverse impact concerning this project?
A I'm not aware of any communication.
Q That includes withdrawing adverse impact finding as well?
A I have not seen any evidence that that finding has been withdrawn.
Q Given your level of familiarity with the project, has the Park Service alerted Ecology that it had concerns with EPA's modeling analysis in the Sumner of 2016?
A I was aware that through, like I said, my proximity to the permitting staff, I was aware that it had come up and that there were issues.
Q Is it your position that if BP is affecting haze after

this project, you will require controls to address that, you will require controls from BP to address that?
A BP will be evaluated, as other sources will, for whether there are available and appropriate controls that can be installed, and, if so, they will be required as part of the regional haze for reasonable progress goal for 2028. I cannot give you an answer there will be a reduction.
Q Based on what information?
A Based on the analysis has not been started or completed.
Q Does that include pollution controls that are equivalent to BACT as we are discussing here?
A Those are the kind of controls that would be evaluated.
Q Regional haze provisions don't address deposition, right?
A That is correct.
Q When you mentioned earlier that all the BART sources would fail the Q/d test, that included BP, correct?
A That is correct.
Q Mr. Newman, could you please turn to tab 9 in Ecology's exhibits.
A Yes.
Q Mr. Newman, did you prepare this?
A No, I did not.
Q So is your testimony based on you reading this information, or reading from it?

A I helped prepare it; I did not prepare it. My work was principally on page 2.
Q Based on your knowledge of the project, is the 10,000 threshold what Ecology applied in this case?
A I believe that's what the permitting staff applied. I would have to reread the support documents to determine that for sure.
Q Mr. Newman, could you please reference Ecology Exhibit 23, page 4.
A Yes.
Q On that page, EPA notes in 2001 dollars, correct, in that footnote, or in that bullet point, excuse me?
A The document was dated in 2001, and I do not remember that the document actually stated what year dollars those were, and they may have been 2000 or 1999.
Q Mr. Newman, are we looking at the same document, page 4?
A You said Ecology Exhibit 23.
Q Yes, page 4. And it says --
A It says in 2001, excuse me.
Q The next line, "This guidance used a cost effectiveness threshold of $10,000 per ton of NOx controlled in 2001 dollars."
A Yes, I agree. I misread the bullet.
Q I would like you to then please turn to page 6. Please reference the middle of the document. EPA advises that

states must consider inflation, right?
A I have not seen any EPA document that advises we must consider inflation.
Q Even the letter that sits right before you?
A Even though that sits right before me. I have not been advised by EPA of that. I don't read every EAB appeal decision.
Q When is the last time that you were advised by EPA about that?
A I don't believe I've ever been advised by EPA on inflating costs.
Q With that said, where does your knowledge then come from about that?
A About what?
Q About the inflation.
A Because I've never been advised --
Q No.
A -- of that knowledge?
Q Yes. You're saying that you have never been advised and so you don't do anything beyond that. So do you ever look beyond the scope of just being specifically directed by EPA, I mean, do you look at --
MS. SHIREY: That's kind of a vague question. I wonder if you could rephrase the question.
MR. WISE: I think I'd let her finish

the question.

MS. SHIREY: Sorry. I thought she was done.

MS. BENNETT: I'll withdraw the question.

Q (By Ms. Bennett): You determined earlier in your haze plan work that BP adversely affects the parks, correct?

A Yes.

Q And based on that rudimentary understanding of the project, will this project increase emissions from BP?

A Yes.

Q Do you know what emissions data BP has supplied the Park Service?

A No.

Q Do you know what emissions data BP has supplied Ecology?

A They supplied Ecology what was in the application.

Q So are you aware of the fact that BP did not provide either hourly or 24-hour emissions data to the Park Service?

A I'm not aware that they did or did not.

Q Are you aware of the fact that BP did not provide either hourly or 24-hour emissions data to Ecology?

A If that's what was in the application, that's what was in the application. I did not go through the pages of the application; it was not part of my job.

Q But you did say you were familiar with --
A I'm familiar with it on general terms. I am not a detailed reviewer of the permit. It's not mine to evaluate.
Q You testified that process delays in permitting can be undesirable for time and cost to the company, correct?
A What was the first --
Q You testified that process delays in permitting can be undesirable for time and cost?
A Yes, I did.
Q Time is a financial consideration, correct?
A Yes.
Q Delays in business is also a financial consideration?
A It's a business decision people make.
Q So a company might install BACT-level controls to save that time and cost, correct?
A They might install LAER-level controls to avoid it.
Q They would not install BACT?
A They might install LAER, not just BACT.
Q So both?
A Either.
Q You testified consent decree is extortion.
A Every consent decree that I have been involved with from EPA is some form of EPA owns the -- EPA has the source in their sights and the source doesn't have lots of

wiggle room. EPA usually dictates the control technologies that get installed.
Q I want you to refer to Ecology tab 8, page 22.
A Report page 22?
Q Yes.
A Okay. Just checking.
Q Mr. Newman, could you please refer to NOx and stationary sources in that.
A Yes.
Q Is th eCherry Point Refinery one of those sources?
A Yes, it is.
Q Can I please point you to the 2011 number and ask you how much of that was from Bp's Cherry Point Refinery?
A Not without the spreadsheets that are behind this.
Q Could I have you reference the chart on page 15, the bar graph for BP Cherry Point Refinery.
A Yes.
Q So based on that chart, in 2011, NOx was at 2,000 tons per year, correct? That's page 15.
A Yes. So which year?
Q 2011.
A 2011 would have been 2,000 tons, yes. Sorry, I may have written it all; I forget all the details.
Q No problem. Understandable. Based on that chart, they have been near that level for the last several years,

correct?
A They've been decreasing emissions over the last several years, but, yes, they're still above 1500 tons.
Q So I would like to refer you back to page 22.
A Mm-hmm.
Q Based on the chart on page 15 and the data from 2011, in 2011, BP was roughly 10 percent of all stationary sources, correct?
A Looks to me like it's probably closer to 9 percent, but in that range.
Q Give or take. And if you compare the tables on page 23 and page 15, you show again that BP is roughly 10 percent of sulfur from the stationary sources, correct?
A Yes.
Q Thank you.
MS. BENNETT: Nothing further, Your Honor.
MR. WISE: Thank you. Any further cross?
MS. POWER: I have one redirect question if I may, if that's all right.
MR. WISE: All right. You can start redirect.
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REDIRECT EXAMINATION

BY MS. POWER:

Q Mr. Newman, just following up on the last line of questioning, you were asked about the role of BP essentially with respect to its emissions, and I just want to clarify both with respect to that last line of questioning as well as with respect to your answer regarding BP and other BART sources failing Q/d previously, is that with respect to the entire refinery or with respect to the coker heater project at issue in this case?

A The entire refinery.

Q Okay. So it is not specific to any emissions related to the coker heater; is that right?

A That is correct.

MR. WISE: No other redirect?

MS. SHIREY: I have nothing.

MR. WISE: Board questions.

EXAMINATION

BY MS. MARCHIORO:

Q In terms of regional haze and the 2064 term, something I am really looking forward to, you were asked about tools and various things that you would be looking at. I am curious, what is enforceable? What is it you could do?

My understanding of these air permits and one of the reasons why there is a lot of concern when they're issued is it's not like an NPDES permit that comes in every five years for tuning up and ratcheting down. So what tools do you have that are enforceable that can actually make a change at a facility? We're not going to talk specifically about BP Cherry Point.
A The RACT process is probably the best tool that we have in our tool box.
Q What triggers RACT?
A One of the things that can trigger RACT is a federal requirement. Other things are ambient air quality problem that's attributable to the source. There's five different things that I can't remember what they all are right off.
Q So an ambient air quality problem that's attributable to the source means it would have a degradation of air quality?
A Yes.
Q So let's say it's a degradation of air quality. When you go in and do that RACT analysis, is it specifically limited to that particular air quality problem or is it a fresh look at the entire facility?
A I would say as the agency, it's a fresh look at the emissions from the facility that affect the problem.

The companies will often say it's only to the extent of the pollutants that affect the problem. The RACT process has a step in which we have to identify the pollutants of concern that are being addressed, and that's where we look at what are the pollutants that we have to deal with, which may be beyond just the narrowest of what's the ambient air quality problem that we're addressing, as it may be the only opportunity we get to do anything to the plant for a very long time.

Q Is that one of those points that is hotly debated between the regulated community and the regulator?

A Very hot.

Q And you're not in EPA so you don't feel like you've got the big stick?

A I don't have an EPA stick in my pocket.

Q I want to ask you a little bit about BACT and Ecology's Exhibit 9, which was the chart.

A Yeah.

Q I'm just trying to get a sense of --

MR. WISE: Do you have the number on that exhibit?

MS. MARCHIORO: Exhibit 9, Ecology 9.

Q (By Ms. Marchioro): So you have these different numbers. I know you helped, but didn't prepare this, but I'm just trying to understand. And there is a

$10,000 figure that's been discussed as the threshold here. When you have these times when folks are either voluntarily putting in, let's say it's an SCR, they're voluntarily putting it in or it's what is appropriate for the unit, I thought you said, and you're not calculating any costs, so how do you ever get yourself with enough information to get a better handle on what the true cost is or what is a more appropriate, I would say, BACT economic cost, because it seems to me every time people do it and you don't take the cost information, you're losing an opportunity to fine tune your number.

A Right.

Q And so what do you do about that?

A That's where we have to look at what's going on in other states, so that's the comparative costs that other facilities are incurring for installation of controls.

Q So we looked at that footnote that had all those different costs, I can't remember which document it was, and we had the low end of $5,000 in the midwestern states, I recall, and then there were some that were up to 24,000. So how do you then not look at those and say -- do you do an average or what do you do with that and say maybe 10,000 is a little light?

A Well, a lot of it is looking at so what are they doing, how much controls do they already have in their state, what's the sources they are looking at, because the cost effectiveness can vary by source, not just by pollutant. So it requires more than just looking at, well, that's the range that's been used so what have you been applying it to and how many of these do you actually get, or is this just like is my state policy is that's the number, therefore, if you're below that, that's what you do. We've never established a state policy in that way. We've always looked at what's the comparable cost of other people.

Q Okay. Let me ask you about cost estimates that you get in the BACT analysis. So let's say the cost estimates are enough above your threshold that you have either got your pencil out or it's not -- I'll start with the other direction. Let's say you're just below your threshold, and within a certain period of time and let's say that the, I saw this in one of documents that makes it possible, is that occurrences, let's say steel just for whatever reason, tariffs or otherwise, it goes up, the cost of steel goes up. Can a company come in after you've made a BACT determination and say, hey, wait a minute, we've now gone from $9,500 per ton to $13,000 per ton; therefore, we're above your threshold, we can't do BACT?

A I can't recall anybody ever asking that form of the question. So this is going to be more conjecture than real, but this is the approach. First off, if a permit has been issued, BACT has been established, costs went up, it's kind of tough. If the permit hasn't been issued, there may be grounds to go and re-evaluate BACT at that point, but it's going to be a re-evaluation based on the new condition, it won't be, oh, costs went up, we can't do it anymore.

Q So the same would be true if costs went down. Once you have given someone the opportunity not to install BACT, you can't come back later and say, oh, by the way, your assumptions have been proven a little bit off, you fit and, therefore, you shall?

A That is correct.

Q And Ecology Exhibit 19, that's the brand-new excerpt from the Cost Manual; is that right?

A Yeah, 19 is the excerpt from the November edition.

Q So I want to talk to you a little bit about that interest rate. I'm just trying to understand if you've been instructed by EPA to always use 7 percent, why is EPA calling it a default rate then?

A I don't know other than it's the number. In this case, they portray it as it's the number to use if you don't have anything else, which makes it default.

Q And so I'm just curious about that anything else. Is there an effort made by Ecology to go out and look for anything else?

A Up until the advent of this manual, there has been no reason to go look for anything else.

Q Can you explain that a little bit further?

A Well, as I tried to explain earlier, until this, until November 17 when this final update of this, update to the Cost Manual chapter came out with the statement that you use other than 7 percent as the preferred interest rates for calculating capital recovery factor, not just the default but the answer is you always use 7 percent as they did in the fifth and sixth editions of the manual.

Q I'm going to have you look then at Exhibit Ecology's 15, and specifically at page 2-13. I'm probably confusing myself; at least I'm hopeful that you will fix that problem.

A Okay.

Q In the first full paragraph, it says OMB sets the social and interest rate for government analyses at 7 percent and then there have been -- prior to that there is a discussion of different social interest rate versus I think the other real interest rate. So the next paragraph goes on to talk about the social interest rate, et cetera, and then you get to the end and the last sentence, and this is where I am getting confused, because it talks about EPA has this interest rate different from EPA's 7 percent, then there are these customized interest rates in each chapter of the manual. That's why I am getting confused, because it seems to me if there was a default, there wouldn't be these spreadsheets and things in their Cost Manual to come up with a different interest rate, so can you explain that.

A Okay, the spreadsheets referenced, in order to make the spreadsheet work for trial purposes, they have to have an interest rate installed so they put 7 percent into the spreadsheet so that the user then can vary that interest rate if they so choose. It's one of many variables that can be installed in the spreadsheets.

Q And the user in that instance is, for example, the Department of Ecology?

A That's correct.

Q So there is some authority there, if you had chosen, to adjust the interest rate?

A That is correct.

Q Okay. Thanks very much.

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EXAMINATION

BY MR. WISE:

Q You mentioned RACT, R-A-C-T I am assuming. Could you tell me more about that.

A Reasonably available control technology is a provision in Washington State Clean Air Act that allows the Department of Ecology to require modifications in addition to emission controls on sources in the state. It directs the methodologies so that if there are two industries in a source category or fewer, we can do it by individual to the source. If there are three or more, we have to do it by regulation, and provide some outline -- it's a criteria by which we can use to require as a threshold requirement to go into the process.

Q Okay. Thank you.

Ms. Brown.

EXAMINATION

BY MS. BROWN:

Q I'm still curious about the cost effectiveness threshold and how that's established by Ecology. I think you said at one point that there's no state policy, and my understanding is there's no state rule that sets the cost effectiveness threshold.

A That is correct.
Q So who in Ecology sets it, how -- what's the process there? Do you just look at each application and decide, okay, for this app, it's going to be this level; how do you do that?
A I hate to say it, it's not a lot different than we look at each permit on its own merits and make a decision. We have rules of thumb that we have developed over time, as mentioned in the one exhibit, that used to be $2,000 a ton. During my tenure of supervising the unit, that grew to 4 to $7,000, depending on pollutant to the source. Since I left being supervisor, it's continued to grow. It's been reflecting costs that we're seeing in Washington and costs that these sources are incurring in other states for the installing of the various control technologies.
Q So then industry doesn't know what that number is?
A They won't know that any better ahead of time, no. They might know this is what it was last time.
Q Okay. All right. Thank you.
MR. WISE: Ms. Bennett, any follow-up questions?
MS. BENNETT: Yes, Your Honor, just a few.
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FURTHER EXAMINATION

BY MS. BENNETT:

Q You mentioned RACT in your testimony to both Judge Marchioro as well as Judge Wise, correct?

A Yes.

Q That's Reasonable Available Control Technology, correct?

A That is correct.

Q That's not as stringent as BACT, right?

A No, it is not.

Q BACT is best achievable control technology, correct?

A Best available control technology?

Q Best available. Excuse my error.

A Yes.

Q Thank you.

MR. WISE: Any other follow-up questions?

Ms. Shirey.

MS. SHIREY: Just a couple.

FURTHER EXAMINATION

BY MS. SHIREY:

Q So you mentioned or you were just asked that RACT is one of the tools you have to meet the reasonable progress goals under the regional haze program. Is that the only tool?

A Like I mentioned, it is the best tool in my tool box. I also have the ability, I believe, to use EPA's four factor process in order to do the evaluations and establish limits.

Q Is that four factor process established somewhere in EPA regulations?

A It's in EPA regulation and it's part of the Clean Air Act.

Q Okay. And getting to the question of interest rates, have you ever asked EPA if you could use a different interest rate in a BACT cost effectiveness evaluation, or had a source ask EPA if they could use a different interest rate?

A It did come up at least once while I was supervising the permit unit, and the company wanted to use a much higher interest rate because that was their actual cost of money, and EPA said no, use 7.

Q Thank you.

MR. WISE: Ms. Power, any follow-up?

MS. POWER: Nothing. Thank you.

MR. WISE: Thank you, Mr. Newman. Ms. Shirey, do you have another witness?

MS. SHIREY: I do. Gary Huitsing.

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GARY HUITSING, having been first duly Sworn by the Certified Court Reporter, testified as follows:

DIRECT EXAMINATION

BY MS. SHIREY:

Q State your name and spell your last name for the record.

A Sure. My name is Gary Huitsing, G-A-R-Y, last name spelled H-U-I-T-S-I-N-G.

Q And where do you work at this point?

A I currently work at the Department of Ecology building in Lacey, Washington.

Q And what is your job there?

A I'm a permit and policy engineer for the air quality program.

Q Can you tell me something about your education?

A Sure. I used to be a teacher. I have a degree in secondary education. I went back to school and earned a degree in atmospheric science from the University of Washington and I stayed at the University of Washington and earned my master's in the civil engineering department. At the time they had an air resources division. Since then, they have changed the name of the department to civil and environmental engineering. And I have a master's of science in engineering from that

civil engineering department, air resources.
Q Are you a professional engineer in the state of Washington?
A Yes, I am, I obtained my license in 2006 and it's current as of today.
Q Could you turn to Ecology's Exhibit 1. It's that book right in front of you.
A Okay.
Q Do you recognize this document?
A Yes, I do.
Q Can you describe it.
A Sure. It's my resume’.
Q So I want to go down this a little bit and look at your experience. What kind of work have you done since you got your degree in engineering?
A Oh, I've been an environmental consultant since I got my degree. I also did some part-time air testing for air sampling companies. And then, of course, Department of Ecology.
Q So how long have you been doing air permitting work?
A Air-related work since approximately 2000, 2001 to the present. Off and on as a consultant. You usually get hired in a big air project and then the project is over and they'll throw you in some other media, ground water sediments, stormwater, until they get another air

contract and you're back on doing air again, but mostly air.
Q I see on here that you worked for Landau & Associates. What did you do at Landau?
A I started at Landau in 2003 and that's pretty much it. They had contracts for air-related projects and most of my time there was involved in air. Like I said, I deviated into other media also when work in air was low, but mostly air, preparing applications for different facilities, air permit applications for clients and submitted them to the Department of Ecology on behalf of a client.
Q Did you do any BACT analyses or did you work on BACT analyses in that job?
A Yes, I did.
Q And what was your role in those BACT analyses?
A I prepared the BACT analysis.
Q What kind of information would you get typically in order to prepare those analyses?
A Well, you're trying to get costs, you're trying to make sure the steps were done right, the top-down analysis, we call them 1 through 5. I identify and eliminate technically infeasible options, rank the rest and then evaluate the three, energy, environment, and economic impacts, and finally make a selection.

MS. SHIREY: I would ask the board to admit Ecology Exhibit 1 into evidence.
MR. WISE: Any objection?
MS. BRIMMER: No objection, Your Honor.
MR. WISE: Ecology Exhibit 1 is admitted.
(R-ECY-1 admitted.)
Q (By Ms. Shirey): So how long have you been at the Department of Ecology?
A I started in August of 2012.
Q So about six years?
A That's right.
Q And what do you currently do at Ecology?
A Currently, I'm engineer in support of permitting and policy.
Q Looking at your resume’ here, it looks like your job changed at Ecology in 2016; is that right?
A That's right. I started at Ecology in the PSD program, although, even then, I had some other roles, but primarily doing permitting. I did do a RACT analysis, that project ended, and then I pursued another opening. There was an opening for permit and policy engineer and I started that in November of 2016. Since I was still working on two PSD projects at the time, PSD lead for a

group, Marc Crooks asked me to continue those two projects. One of them was the Tesoro project mentioned today, that has since been completed, and BP is my last PSD project.
Q So you just answered my next question. As part of your job, were you involved in the PSD permit for the BP coker heater project?
A Yes, I was.
Q And what was your role in that permit process?
A I was the permit engineer for the coker heater replacement project.
Q And what does that mean, what did you do?
A So I would review the application when it came in. Initial application came in in, I believe, September of 2014. We're required to prepare a completeness determination, whether the application is complete or incomplete. We have 30 days to do so. And we submitted an incomplete determination in October, I believe, of 2014. And since then, they've since submitted a new application. I refer to it as the March application. We're referring to it as the consolidated June application. Technically, it was the March application that came in. I determined it to be complete in April. Once again, I had 30 days to do so. There was some correspondence. I thought it would be convenient, as we

anticipated going to public review, to consolidate the March application with that correspondence and thus we have a June 2016 application, and I've been working with it ever since.  Response to comments, we received numerous comments through to the present.

Q	So did you sign the permit?

A	I did.

Q	And did you stamp the permit with your professional engineer stamp?

A	Yes, I did.

Q	What does it mean when you stamp a permit with your professional engineering stamp?

A	To the best of your knowledge and engineering discretion, it satisfies the requirements that you're asked to look at, in this case, WACC, PSD requirements, down the line, everything that's required to be done. And if they satisfy all those requirements, my understanding is we have to issue the permit.  Until we had all the information and a complete application and answered the responsive comments, we did so, we issued the permit.

Q	And as part of your review, did you ask BP to answer questions, to review things, did you have questions for BP?

A	Yes, we did.

Q I want to turn to Exhibit JE-1. Do you recognize this document?
A Yes, I do.
Q What is it?
A That's the June application that I just referred to for Cherry Point coker heater replacement project.
Q I want to turn, and I apologize because I did not write down the JE number on this, and it's going to be hard to find, but when I find it, I'll let you know. It's Appendix G, pages 1 through 5. Appendix G is JE000249.
A Okay. I have it.
Q Okay. And I'm turning to -- well, let's start with page 3 of that, which is JE000255. Let's go back to 253. Do you see the JE numbers there on the bottom?
A I see it. I'm there.
Q So what is this? At the top it says, "Response to Comments." What comments are those, who is responding to what?
A Oh, okay. This looks like BP's response to our incompleteness letter, the October 2014 incompleteness letter, and here is the response to all of our concerns.
Q I just want to highlight a couple of these to see what kind of questions you asked. What was Ecology question number 2?
A You mean read that whole paragraph?

Q Well --
A I can summarize it. I spent, it was me, it was not National Park Service, I reviewed our emission inventory and emission inventory personnel Sally Otterson, I asked her for the emission inventory for the facility. I looked through every single baseline emissions for this project, every unit, and I found some discrepancies and I list what those are.
Q Discrepancies between what?
A Between the baseline emissions listed in the application and those in our emission inventory.
Q And turning a couple of pages to Ecology question number 12.
A Okay.
Q So what were you asking for there, what were you looking at there?
A Okay. It involved gas treatment system. We asked for a clear analysis as to how they determined the cost per ton.
Q It wasn't just gas -- can you look at that?
A And pressure rising off-gas with new compressor.
Q And what were your questions there?
A We asked for a clear analysis of how they determined the cost per ton of these options and on what basis the estimated values in the table they gave us were derived.

We also asked if the 7 percent interest rate used in the calculations was outdated or not.
Q Okay. And question 13, what was that question looking for?
A So I did my master's thesis on wet electrostatic precipitators and I was surprised not to see that listed as one of their control options, so I asked why they didn't include it. I asked them to include it.
Q Question 15, what is that?
A Oh, yes. I wanted to know where their safety factor came from and what are their emission factors.
Q And as part of what kind of analysis?
A It was a particulate matter BACT emission factor.
Q I think that's enough. I just wanted to give a sense of questions you had asked. Are these the only questions you asked BP?
A No. As you can see, there's a few other pages. Our modelers also submitted some of these questions. These are the questions we asked them formally as part of the incompleteness letter, and we did have continued correspondence during this time asking for clarifications.
Q As part of your evaluation or your review of the permit application, was the National Park Service required to be involved in this permitting process?

A Yes, they were.
Q And why was that?
A Because for PSD projects, I think our WAC specifically says we need to starting from the beginning -- actually, the onus is on the applicant. We need to make sure the applicant submits the application to the federal land managers. I specifically remember working with Kyle Heitkamp, giving him new updates of who those contacts were and he did submit the application. So he'd been involved from the beginning. Even before that time, Kyle Heitkamp mentioned the pre-application meeting and, yes, so they'd been involved early on. I believe that was March of 2014.
Q Did the National Park Service provide an analysis as part of the permitting development in this case?
A Any specific time frame or early on or later?
Q Whenever.
A Yes, they did.
Q Did you review that analysis?
A Yes, we did.
Q Did you reach any conclusions after reviewing the National Park Service analysis?
A Yes, we did.
Q And what did you determine?
A We didn't agree with the overall adverse impact

determination, but as we cite in our technical support document, we thought they were helpful comments and we went back to BP and said we think you need to follow FLAG more closely. I think the baseline was one issue and others have mentioned it. Yeah, we looked at it, reviewed it and went back to BP and said we would like you to address some of these things.
Q So was a baseline the only question?
A The only concern?
Q Yes.
A No. There were issues of using capable of accommodating, as I mentioned, in our technical support document, that's a PSD concept, and we said shouldn't use that for AQRVs.
Q Can you explain a little bit what capable of accommodating means?
A Sure. PSD allows demand exclusions. It says you shall exclude in the PSD regulations. Eric Hansen mentioned CFR 52.21 allows the applicant to exclude emissions that they could have accommodated and have documented at some point that they could operate at that level for at least 30 days, and if they're not using those emissions, you can exclude them as part of this provision, and they did so. And we said that's fine for PSD applicability; for AQRVs, we don't see that listed in the FLAG manual.

Q Could you turn to Joint Exhibit Number 2. That's in that same binder you are in now. I believe you testified that you asked BP to redo its analysis of AQRVs; is that right?
A Yes.
Q Joint Exhibit Number 2, do you recognize this exhibit?
A Yes. This we refer to as the November supplemental.
Q Is this BP's revised AQRV analysis?
A Yes, it is.
Q Did you review this analysis?
A Yes, we did.
Q Did BP change the baseline that you asked them to do?
A They did.
Q And did they change anything else?
A Yes, they did.
Q What else did they change?
A These numbers no longer include capable of accommodating demand exclusion numbers just as we asked them.
Q Is there anything else that is different in this?
A Yes. They also asked for a lower limit than they had initially asked for for SO2 from 40 pounds per hour to 37 pounds per hour.
Q Does the permit that was issued reflect that change?
A Yes, it does.
Q Okay. So I want to turn to in the same exhibit, page 9,

which is JE000309, and I want to look at Table 3.
A Okay.
Q So can you describe what that is?
A This is their, I call it, revised Q/d analysis, and we see with this new revision, their Q/d values are still less than 10.
Q So we've heard a lot about Q/d, and I hesitate to ask you to explain once more what Q/d is, but I wonder if you would.
A Sure. It's addressed on page 18, the bottom right side of the page in the FLAG manual where it described the four pollutants you should sum up, Q them up. They are sulfur dioxide, nitrogen oxide, butane and sulfuric acid. And you take that Q value, and it's described as the -- specifically described based on a maximum 24-hour values, talking about the coker heaters. And then the distance, "d" represents distance, as we mentioned earlier, to the closest Class I area, 78 kilometers at Olympic National Park, and 102 and the rest of them have a farther distance, but if you divide the Q value by the "d" value, every one of them is less than 10.
Q I am going to stop you because you're going on a bit. You mention the FLAG guidance at page 18. I want to turn to that. So that's JE-11, page 18, which is JE001141.

A Okay.
Q So you were talking about, I believe, how the guidance here talks about how to calculate Q/d; is that correct?
A That's right.
Q And so, again, what were the pollutants involved?
A They are listed here, SO2, NOx, particulate matter 10 microns or less, and sulfuric acid.
Q And what are you looking at about those emissions, about those pollutants?
A According to FLAG?
Q Yes.
A You look at their annual emissions in tons per year based on their 24-hour maximum allowable emissions.
Q Okay. And so that's Q?
A That's Q.
Q And what is "d"?
A "d" is the distance in kilometers from the Class I area.
Q And what does this say about Q/d?
A It says if the distance to that Class I area is 10 or less, the agencies would not request any further Class I AQRV impact analysis from such sources.
Q Okay. You said if the distance is 10 or less?
A If Q/d is 10 or less.
Q So did BP follow this guidance in its November 2016 Q/d analysis?

A Yes.
Q So I want to go back to JE-2, page 5.
A Okay.
Q I believe on page 5 they talk about the updated screening procedure. Do you see that?
A Yes.
Q So what did they say they did? What did BP say it did?
A Sure. So they say, "The modeling protocol for the PSD permit application presented a Q/d screening analysis that indicated further evaluation of AQRV was not warranted," and then they provide a table showing the results.
Q All right. I think it refers to adjusted annual emissions, updated Q/d from coker heaters adjusted to annual emissions. Do you know what that means?
A Yes.
Q What is that?
A So it's based on a maximum 24-hour emission rate, so that's the starting point, and FLAG says to use annual, and so you adjust it to the annual emissions.
Q By multiplying times --
A That's correct, you adjust them up to figure out the hours in a year, and you want to use tons also.
Q So you convert pounds per day into pounds per year?
A That's correct.

Q So NPCA said BP did not include all the relevant emissions to calculate Q/d. Can you explain what emissions NPCA thinks BP should have included?
A The term we have used, affected units.
Q Okay. So emissions from the affected units?
A I'm sorry, the emissions from the affected units.
Q Will the 24-hour emissions from those units increase?
A No, they will not.
Q So should their annual emission increase be included in the Q/d analysis?
A No, because they're based on 24-hour maximum level emissions.
Q The Q/d analysis is based on that?
A That's correct.
Q So turn to, I think you already said this, but turn to page 9, Table 5.
A Okay.
Q The updated Q/d summary, and what does that show?
A So, yes, as I mentioned earlier, it shows results -- let me back up a little bit. Shows Class I areas, lists them out, what each Class I area is, the distance to each Class I area, and then the Q/d values with new cokers only, and then if they also take credit for the removal of the existing heaters, which they will be removed, this table also shows the Q/d results of that

calculation also.
Q Okay. So did you do a Q/d analysis on your own or to supplement this one?
A Recently we did. We try to accommodate the question we don't think you should do it this way, but even if you take a step down that road, we still see Q/d values less than 10.
Q I wonder if you could turn to Ecology Exhibit Number 5.
A Okay.
Q So do you recognize this document?
A Yes, I do.
Q What is it?
A So this is extracted from BP's November supplement, Table 2, which they used for long-term AQRV analysis for deposition.
Q Before you get into too much detail, just tell me generally what this is.
A Sure. This lists those pollutants we just mentioned for Q/d analysis for both the coker heaters and the affected units.
Q So is this the Q/d analysis that you performed?
A Yes.
Q Thank you. So now did you do the Q/d analysis, the calculations on this page?
A Yes.

Q Now you can get into detail about what this document shows.
A Okay. At the top are the coker heaters, the only units that have maximum 24-hour level increases, so potential to emit and appropriate. For the rest of the affected units, we added the increase due to the project and added up the four pollutants I mentioned. We added that fourth pollutant on the right side of the page because this table was used for something else by BP which does not need sulfuric acid. So we added sulfuric acid and came up with the sulfuric acid number, we used the ratio from their application. We even looked at it from a more conservative approach of how much sulfuric acid is used. Summed them up, divided it up by the closest Class I area, which is that 78 kilometers from the facility and we still see numbers less than 10.
Q So I want to point you to the farthest left-hand column, down toward the bottom. Do you see the row that says "notes"?
A Yes.
Q And then it says asterisk star Q equals.
A Yes.
Q What is that?
A So the number there is 589.8. That is the sum of the green boxes, four green boxes, in this chart.

Q Okay. And what is the one below it which has two stars and Q?
A Just looking at sulfuric acid for a more conservative overestimated point of view, assuming up to 20 percent of all the SO2, assuming sulfuric acid represents 20 percent of the SO2 for all those other units, which we have no indication that it does, but just like to be conservative, overestimate, and that number, 605.7, is the sum, using that higher estimated sulfuric acid number.
Q So you said, I think, a minute ago that you provided the h2so4 numbers; is that right?
A Yes.
Q And where do they come from?
A Like I said, they came from the application. We used a ratio of what the application showed sulfuric acid was to SO2.
Q In other words, you're saying if you have got a certain amount of SO2 emissions, then you'll also have a certain amount of h2so4 emissions?
A That's the way it's presented in the application, in those ratios.
Q And it would be a certain fraction, the amount of h2so4 would be a certain fraction of SO2?
A Yes.

Q So you've come up with a range of -- you've got a high and a low range for Q; is that right?
A Yes.
Q And so then you have the nearest "d." Do you know what national park that is?
A North Cascades.
Q And then you have two different Q/d values; is that right?
A Yes.
Q A high and a low. And what are those?
A The lower one is 7.6 and higher one is 7.8.
Q So what were you trying to show with this document?
A So we believe BP did it right and what I just did was an incorrect way to do it, but trying to accommodate and look at a reasonable approach that if you're going to include the affected units, you should look at just the increases from those units, not -- if you want to look at the annual emissions from those units, you look at the actual annual emissions, not invented 24-hour increases which don't exist. And this is the highest value that we could find, using the most conservative overestimated method, and it was still less than 10.
Q Thank you. So in paragraph 22 of his prefiled testimony, Mr. Gebhart says Q/d is irrelevant for BP's project because the two affected national parks are

already impacted by emissions. Do you agree?
A Could you repeat the first part.
Q So in paragraph 22 of Mr. Gebhart's prefiled testimony, he said that Q/d is irrelevant here because the two national parks are already impacted by emissions. Do you agree with that?
A No, I don't.
Q And why not?
A There is nothing in FLAG that says a facility that already has impacts cannot use Q/d.
Q In your experience, have Q/d analyses been used to screen out projects from other facilities that impact Class I areas?
A Yes.
Q Could you describe them?
A Sure. Concurrently with this permit, I also prepared a Tesoro Refinery clean products upgrade project, and they also used Q/d and screened out -- and they did not do visibility and deposition analysis, they just stopped after Q/d showed that the value was less than 10.
Q Thank you. In the BP permitting process, did you get any feedback from any federal land managers that Q/d was relevant?
A Yes, we did.
Q So what did you get?

A We got an email from one of the federal land managers sent to our modeler, saying that as long as -- this is with respect to the coker heater replacement project -- said as long as Q/d is less than 10, I believe his exact words were we have no further concerns, or something along those lines.
Q Can you turn to Ecology Exhibit Number 7.
A Okay.
Q Can you describe this document?
A Sure. This is the email I just referred to a minute ago.
Q And who is it from?
A It's from Rick Graw. I believe he's former Forest Service federal land manager. I think he's still involved somewhat, although, James Miller is currently the Forest Service contact for us. And it's an email to Clint Bowman at Department of Ecology, who has since retired. And it says -- well, let me give you the date. This is Monday, the 24th of March, 2014. And Mr. Rick Graw from FLMs says, "If all the Q/ds remain less than 10, I have no comments."
Q This is the email that you were referring to a minute ago that Ecology got?
A Yes.
Q Okay. I want to turn to Ecology Exhibit R-6.

A Okay.
Q Do you recognize this document?
A Yes.
Q So what is this?
A This is the March 2014 application from BP to Ecology that I referred to earlier.
Q What part of the application is it?
A Oh, okay, I'm sorry, this is two years before then. This is the modeling protocol. It's not the application, it's the modeling protocol submitted prior to the March application.
Q What did BP do with this document? What was the purpose of this document?
A We had pre-application meetings for all of our PSD projects that we considered very important. We give twice the amount of time for PSD major projects pre-application meetings than we do for minor NSR projects. We want to make sure everyone is on the same page, save time, and that was the purpose for this pre-application meeting. Even prior to the meeting, this document was being sent to our modelers and correspondence had already begun even before Marc Crooks and I were involved in this project.
Q And so this modeling protocol, what was it used for, what was it designed for?

A Like I said, we want to make sure everyone is on the same page, that the approach to the modeling that BP was proposing to use would be agreed upon or if there was any questions, they could be sorted out at that time.
Q I want to turn to page 18 of this document.
A Okay.
Q So does this document explain the emissions that BP was going to include in its modeling analysis for the AQRV analysis?
A Yes.
Q And could you look at the first paragraph on page 18. Does that describe what those emissions were going to be?
A So the top of page 18 describes their preliminary Q/d analysis, and they described how they came about coming up with these values, and they provide the results in a table, which showed that Q/d value is less than 10 even for that closest national park, North Cascades, and the value showed a Q/d value of 7.
Q So going back up to the paragraph above the table, what does it say about the emissions that BP was going to model?
A Starting from --
Q Just take your time and read the paragraph so you can refresh your memory about what it says there.

A Sure. So it's written here at the top of page 18, it says, "Table 4 lists the approximate distance between the site and the Class I areas as well as the Q/d total emissions in tons per year divided by the distance in kilometers. A preliminary net emission increase in Q is based on the sum of the 24-hour NOx, SO2, PM10 and sulfuric acid emissions from the two new cokers assuming continuous operation 365 days a year. BP does not expect an increase in short-term emissions from any other emissions unit affected by the project."

Q Okay. So that describes how BP was going to calculate the emissions that were going to be used in its modeling protocol, right?

A Yeah.

MS. SHIREY: And so I would ask the board to admit Ecology Exhibit 7 and 6.

MR. WISE: Any objections?

MS. BRIMMER: No objection.

MR. WISE: Ecology Exhibit 6 and 7 are admitted.

(R-ECY-6 & R-ECY-7 admitted.)

Q (By Ms. Shirey): So once BP had done the Q/d analysis, were they required to do anything more?

A In regards to AQRV? No, they were not.

Q Did BP do anything more?

A Yes, they did.

Q What did they do?

A They did a full-blown analysis of its ability comparing to the FLAG thresholds and a full-blown AQRV modeling analysis of deposition and compared it to the deposition thresholds also listed in FLAG.

Q And for the sake of time, I'm not going to walk through all that, but what did they find; do you remember in general what they found?

A Sure. In general, they found that for visibility, the project's impacts would be less than the visibility thresholds listed in FLAG, and, similarly, for deposition, for both sulfur and nitrogen, the deposition values after modeling showed results less than the DAT, which is the deposition thresholds listed in FLAG.

Q And a few moments ago, you said that you asked BP to redo its analysis. I think we actually covered all of that.

So in paragraph 107 of his prefiled testimony, Mr. Gebhart said the net emissions increase BP used for the deposition analysis in the November supplement is wrong because it compares future projected emissions to past actual emissions instead of comparing the maximum allowable future emissions to past actual emissions. Is that consistent with what you understand

Mr. Gebhart's position to be?
A With regards to deposition, yes.
Q So do you agree that BP used future projected emissions rather than maximum allowable future emissions for the deposition analysis?
A Yes.
Q Do you think that this is a wrong approach?
A No, I do not.
Q Why not?
A Because there are no maximum level increases.
Q And so what do you mean by that?
A They're not increasing their 24-hour maximum increases. Furthermore, FLAG doesn't really get into how to do a deposition analysis. I think BP's approach, their consultant's approach, makes total sense to look at the actual emissions. When you look at a new or modified source, you want to look at its emissions. FLAG is consistent with that. Page 21 of FLAG at the top of the third paragraph on the left-hand side of the page, it says exactly that, that for new or modified sources, you look at its emissions. And new source review, that implied increases, its emission increases. Since it has no 24-hour emission increases, you don't have anything to work with.
Q So the units that were added through the deposition

analysis in addition to the coker heater emissions -- in addition to coker heaters, the deposition analysis looked at a number of other units; is that correct?
A Yes.
Q Were those modified units?
A No.
Q And so I think what you were saying just now was that -- so does FLAG, say, have a deal with units that are not modified?
A It does not.
Q In paragraph 70 of Mr. Gebhart's prefiled testimony, he says that the updated November analysis was incorrect because it doesn't look at emission increases from all of the affected units. First of all, what are the affected units?
A All the units that experience increased utilization due to this project, which will be everything else listed in the application, all the other units except the coker heaters.
Q Were those modified units?
A No.
Q So do you agree that BP's analysis, I'm talking visibility now, do you agree that BP's visibility analysis does not look at emission increases from all the affected emission units?

A That's correct.
Q Do you agree with Mr. Gebhart that BP's method was incorrect?
A No, I do not.
Q Why not?
A As I said, there's no maximum 24-hour increases from the affected units, and that's the criteria, that's the box you have to check for visibility.
Q So in paragraph 73 of his prefiled testimony, Mr. Gebhart says that in order to eliminate the affected units, BP, in effect, subtracted the present maximum allowable 24-hour emissions from those units from the future maximum allowable 24-hour emissions from those units, which comes to zero, because those emission limits have not been changed. Do you agree with that characterization of what BP did?
A And this is with respect to visibility?
Q Visibility.
A I see BP not including the affected units because they have no 24-hour increases, end of story; they just don't have them.
Q In paragraphs 48 and 75 of his prefiled testimony, Mr. Gebhart says that the FLAG guidance on page 24, Footnote 6, which I think we've heard of already, that that governs how BP should have calculated the net

emissions increase. So why don't we turn to that, Exhibit JE-11. So page 24, which is JE001147.
A Okay.
Q So what does Footnote 6 have to say?
A Footnote 6. "Note that this is different from the emission change calculation used for short-term increment, which is calculated as the maximum allowable 24-hour average minus the highest occurrence over the past two years."
Q What is that footnote referring back to?
A About halfway up the page, it's just above the paragraph, the heading "Model Receptor Grid," describing emissions input for visibility analysis.
Q And that paragraph talks about what applicants must do to calculate the 24-hour average net emissions increase, right?
A Yes.
Q And what does it say to do?
A "Applicant should calculate the 24-hour average net emission increase for each pollutant from modified facilities as the maximum allowable 24-hour average minus the actual hourly rate averaged over the past two years." In parenthesis "Annual emissions over past two years divided by hours of operation over last two years."

Q So Mr. Gebhart says that Footnote 6 says you can't subtract maximum past emissions from maximum future emissions to get the net emissions increase. Do you agree with Mr. Gebhart?

A Is he quoting Footnote 6 or is he saying BP did not follow Footnote 6?

Q He's saying -- well, he is saying that you can't subtract the maximum past emissions from the maximum future emissions, and I'm wondering -- I guess the first question is, is that what Footnote 6 says?

A No. Footnote 6 talks about -- what they're asking here is different from calculating maximum allowable 24-hour average minus the highest occurrence over the past year.

Q So in that same paragraph he said that -- in the previous paragraph I mentioned, which was paragraphs 48 and 75, he said that BP made a mistake in its visibility analysis because, in effect, it subtracted the maximum past emissions from the maximum future emissions to get the net emissions increase. Do you agree that that's what BP did?

A No. After we've established that visibility is just for the units with short-term emission increases, we are down to the coker heaters, and for NOx, for example, you can see their maximum allowable limit is 18.2 pounds per hour for each heater, and what they subtracted was not the maximum over the last two years, but they took their facility average of 2014 and 2015, which came to about 16 pounds per hour, or 8 pounds per hour per year, as they show in Table 1 of their November submittal.

Q So that's what they did for the coker heaters. What did they do for the rest of the units?

A For visibility, as we mentioned earlier, there are no 24-hour maximum emission increases, so they didn't have to do anything and they didn't.

Q In paragraph 124 of Mr. Gebhart's prefiled testimony, he says that the National Park Service named five projects that used the approach he is advocating for looking at emissions from a project that impacted federal Class I areas, and he cited to Joint Exhibit 7, so I want to turn to Joint Exhibit 7 at JE000991.

MR. WISE: Ms. Shirey, when you come to a stopping place, we'll take our afternoon break.

MS. SHIREY: Okay.

MR. WISE: Do you have any idea how much longer that will be?

MS. SHIREY: I can wait until we get off the AQRV questions and on to BACT, or I can stop in the middle of the AQRV questions pretty quickly here. Which would you prefer?

MR. WISE: Probably need to stop

sooner rather than later.

MS. SHIREY: Okay. So I will just ask this one question and then we can stop.

Q (By Ms. Shirey): So Joint Exhibit 7 --

A Okay.

Q -- page 991. So Mr. Gebhart cites to this page and he cites to Footnote 37. Do you see that?

A Okay.

Q I need to find it now. So what does Footnote 37 do there?

A It lists some facilities.

Q And what does Footnote 37 refer back to?

A Looks like the second-to-the-last paragraph.

Q And what does that sentence talk about?

A It says, "It is also helpful to consider how modified sources have been addressed elsewhere. A review of National Park Service files found five examples where we had requested that state permitting authorities evaluate the entire source."

Q Okay. So presumably Footnote 37 is listing those five sources?

A Yes.

Q Mr. Gebhart, I believe, testified in response to a question I asked, that he did not provide any information about those five sources. Do you know, did

National Park Service provide any information about those five sources?

A I don't recall.

Q Meaning you don't remember at all or you don't remember seeing anything?

A We've had some correspondence with the Park Service. I don't recall these facilities.

Q Can you tell from the information that you were just looking at anything about the five projects, why they might have been asked to model emissions from the entire facility?

A I don't know.

Q Okay. That's it for now.

MR. WISE: Thank you. We'll take a 15-minute break, come back at 3:15, and we'll continue.

(Recess from 3:00 p.m. to 3:15 p.m.)

MR. WISE: Please be seated. Counsel, I just had a procedural question to start with. Mr. Huitsing has been named as a witness by both NPCA and Ecology, and I'm just trying to figure out the most efficient way to do that. Here's kind of what I'm thinking. Ms. Shirey finishes her direct, then Ms. Brimmer comes up and asks whatever questions she wants, and then we just sort of do it in tandem and work our way through this. What do you think of that?

MS. BRIMMER: I think I can make it even easier for you. I'll forego any direct examination of Mr. Huitsing an I'll just rely on cross.

MR. WISE: Okay. You will just treat him like an adverse witness and start the cross.

MS. BRIMMER: That's okay with me.

MR. WISE: Okay. Well, we can just do that then. And I didn't want to do two sequences.

MS. BRIMMER: I agree. That doesn't make sense.

MR. WISE: Thank you very much. Proceed, Ms. Shirey.

MS. SHIREY: The first thing I would like to do is ask for the admission of Ecology Exhibit Number 5, which is a document we just looked at and contains Gary's Q/d analysis.

MR. WISE: Any objections?

MS. BRIMMER: No objection, Your Honor.

MR. WISE: Ecology Exhibit Number 5 is admitted.

(R-ECY-5 admitted.)

Q (By Ms. Shirey): I wonder if you could turn to Exhibit P-7.

A Okay.

Q Do you recognize this exhibit?
A Yes, I do.
Q And so what is it?
A FLAG Response to Public Comments on Revised Phase 1 Report, dated 2010.
Q Turn to page 2, the portion of the document under Section 2.11, Net Emissions Increase Calculation.
A Okay.
Q So do you know what this is about?
A There is a comment about commenters objecting to the federal land manager approach of calculating net emission increases for modified facilities.
Q And what is the response to that comment?
A Would you like me to read it?
Q I'm fine with you reading it, but if you can summarize it, that would be fine, although, I understand if you can't because it's very term intensive.
A I'll read it. So the response is, "FLAG advises applicants to calculate the 24-hour average net emission increase for each pollutant from modified facilities as a maximum allowable 24-hour average minus the actual hourly rate averaged over the past two years, annual emissions over past two years divided by hours of operation over the last two years. We recognize that this approach is different from the emission change

calculation used for a short-term increment, which is calculated as the maximum allowable 24-hour average minus the highest occurrence over the past two years. The reason for the differing approaches is so that FLMs can better assess the impacts of modified sources on AQRVs especially in a situation where a source does not increase its maximum emissions but increases its annual capacity factor by operating more days throughout the year. By operating more days per year, such a modified source could potentially impact visibility on more days of the year."

Q So does this response say anything about which emission units to use in the analysis?

A It says FLAG advises to use a maximum allowable 24-hour average.

Q From which emission units, or does it say?

A Oh, from modified facilities, it says.

Q Okay. How does this document or this response, in your opinion, apply to the BP coker heater situation?

A So I see two things here that seem clear. It's clearly talking about visibility, that's in the last sentence, so, once again, we go to FLAG's guidance on describing visibility, and we know FLAG was meant primarily but not solely for new source review, so we are talking about emission increases. And so we have already described that only units that have short-term emission increases should be used in a visibility analysis. And what's also clear here is that because they are talking about visibility, there appears to be a contradiction. The second-to-the-last sentence, it says, "The reason for the differing approaches is so that the FLMs can better assess the impacts of modified sources on AQRVs especially in a situation where a source does not increase its maximum emissions." So I stop there, and to substitution, we already know that if a source's maximum emission increases, should look at visibility, and if it does not, don't. So in this situation, saying where a source does not have visibility impacts, we are going to try a way to look at them anyway, which may give them some information on a yearly basis, but it's contradictory to FLAG, as we looked through earlier, describing visibility impacts based on 24-hour maximum allowable emissions.

Q Did you have any other thoughts about that or is that about it?

A Yeah. The person from FLM who wrote this response lacked some clarity on what maybe they meant to say, but it has that contradiction there.

Q Are there any other incongruities?

A Possibly. I don't see them right now.

Q Okay. So did federal land managers have concerns about the BP project?
A Yes, they did.
Q I want to turn to Joint Exhibit 6 at JE000950.
MS. BRIMMER: Can you repeat that number?
MS. SHIREY: 000950.
MS. BRIMMER: Thank you.
Q (By Ms. Shirey): So what is this document?
A The JE000950 page?
Q Yes.
A That's enclosure from the National Park Service entitled, National Park Service, NPS, Analysis of Impacts to Air Quality Related Values for the British Petroleum Cherry Point Refinery, Blaine, Washington, dated December 12, 2016.
Q So did Ecology work with the federal land managers to address these concerns?
A Yes, we did.
Q What did you do?
A Okay. This is one of the comments we received. I said we received many comments during our public comment period, which went from, I believe, November 14th through December 16th of 2016. And on that last day of that comment period, these comments were submitted from

the National Park Service, and we spent the next five months addressing every comment we received, including all of the ones included here from the National Park Service, and our intent was to address them and we felt like we eventually did.

Q Did you send the National Park Service Ecology's draft response to comments?

A Yes, we did.

Q And then what did you do?

A Mark Kirk scheduled two conference calls, made room for two conference calls in the event that maybe it would take more than one conference call to work through these issues. The first conference call, if I got the dates right, was Monday, May 8th of 2017, and the second conference call was scheduled for that Wednesday, May 10th.

Q And so did you have that first conference call?

A We did.

Q And what did you do on that call?

A So we talked through our responses to their comments. Just to give you some context, we received about 134 comments for this project, and I think Earthjustice comments were numbered 1 through 87, or something like that, and from the Park Service, there was I believe around 40 questions, so those would have been comments

87 to 140, something like that, and the remaining comments were from the EPA. By this time we had already worked through all the issues that the EPA had. We did meet with the Park Service also to work through their comments with them.

Q So what did the Park Service have to say on that first conference call?

MS. BRIMMER: Objection. Hearsay.

MS. SHIREY: Well, the board's standard for hearsay is that you will accept --

MR. WISE: That's okay, I know the standard. I'm thinking since Mr. Huitsing was present at the meeting, I'm going to allow it.

MS. SHIREY: All right.

A Would you restate the question.

Q (By Ms. Shirey): So what happened on that conference call with the federal land managers?

A Okay. So we talked with the National Park Service and we basically said, have you read our responses to your comments, and they said, yes. And just talking with Marc Crooks, we remembered language similar to the Tesoro comment where there was a reference to addressing issues to the regional haze program. And we offered to meet again on that Wednesday, May 10th of 2016, and they said that a second meeting was not necessary.

Q Okay. So you cancelled the second conference?
A We did, we did not have that.
Q Did Ecology document this response?
A We did.
Q Could you turn to Ecology Exhibit 3.
A Okay.
Q Do you recognize this document?
A Yes, I do.
Q Did you receive a copy of this document? Were you copied on this letter?
A My name is not on here, but I did get an electronic copy, too, yes, I did.
Q What is this document?
A So this is a letter written by Marc Crooks, the lead of the PSD program at Department of Ecology, responding to the adverse impact determination letter that came in on that December 16, last day of the public comment period, and Marc is addressing the Department of Interior, from which the adverse impact determination came.
Q Could you tell us who Marc Crooks is.
A Sure. He's the lead of our PSD program at Department of Ecology for all the PSD permits in the state of Washington.
Q Okay. And so he wrote this letter to Department of the Interior?

A Yeah.
Q And so does this letter describe the process that you went through with the federal land managers?
A Yes, it does.
Q I think that's the paragraph at the top of page 2.
A Okay. Yes, that paragraph references the May 8th conference call.
Q And does it say what the federal land managers did?
A Oh, yes, that's right, so I did forget that. So during our conference call on May 8, towards the end of the call -- oh, that's the second paragraph.
Q That's okay. Keep going.
A So, yes, we offered to organize a future conference call later that week, as I mentioned, and the National Park Service staff declined the second call but responded that they would write a white paper on their issues and concerns regarding air quality at Class I areas. And the NPS requested that after their white paper had been distributed, they would like to hold a conference call to discuss their white paper. So Ecology, Marc Crooks, invited EPA Region 10 air staff to participate and EPA agreed to participate. And since then, we have not yet received that white paper.
Q So you have not?
A No.

Q Have you had the conference call that was mentioned here?
A We did not have that second conference call, no.
MS. SHIREY: I would ask to admit Ecology Exhibit 3 into evidence.
MS. BRIMMER: No objection.
MS. POWER: No objection.
MR. WISE: Ecology Exhibit 3 is admitted.
(R-ECY-3 admitted.)
Q (By Ms. Shirey): Did you receive any other communication from the National Park Service that influenced your thinking on this, on the National Park Service's thoughts?
A Yes.
Q And what was that?
MS. BRIMMER: I just want to preserve a hearsay objection to this.
MR. WISE: Noted.
MS. SHIREY: I'm sorry, objection to what?
MS. BRIMMER: That he is about to talk about what the National Park Service told him and I wanted to make sure I had a continuing hearsay objection.

Q (By Ms. Shirey): Could you turn to Ecology Exhibit 4.
A Okay.
Q Could you describe this exhibit?
A Sure. This is a letter from the United States Department of Interior written to me, dated April 26, 2017.
Q And from the Department of Interior.
A From the, yeah, and it's listed under the heading, the Department of Interior, specifically National Park Service.
Q Did you receive this letter?
A I did.
Q What does this letter say that is relevant to your thinking about the BP project?
A Like I said, it seemed similar to what we understood from our May 8th conference call, and it seemed to be an acknowledgment that their concerns for the facility as a whole should be addressed through a regional progress phase or, as they word it, of the regional haze rule.
Q Can you point to where the letter talks about that?
A Yes, I can. That would be on page 5 of the letter, it's the second paragraph, or the largest paragraph on that page, and this would be starting at the beginning of the paragraph.
MS. SHIREY: I would ask the board if

we could admit Ecology Exhibit 4 into the record.

MR. WISE: Any objection?

MS. BRIMMER: No objection, Your Honor.

MR. WISE: Ecology Exhibit 4 is admitted.

(R-ECY-4 admitted.)

Q (By Ms. Shirey): So did the National Park Service or Department of Interior file a formal finding of adverse impacts with Ecology?

A My understanding is that the December 16 comment was more than just a comment, it was also an adverse impact determination.

Q To your knowledge, has the National Park Service changed its opinion that the BP facility has adverse impacts on North Cascades and Olympic National Parks?

A I have not heard they've changed their opinion on that.

Q So do you believe anything has changed about the National Park Service's opinion?

A Yes, I do.

Q And what would that be?

A That the PSD program is a different route to address facility-wide impacts than the regional haze rule or program is, but they tried to use the PSD program to attain their goals, and we pointed out to them that

that's not the proper route, to use PSD rules, as applied to new source review.
Q And is it your understanding that they agreed with that?
A Yes.
Q Thank you. I want to go on to the BACT analysis for nitrogen oxides. So as part of your review of the permit application, did you review BP's analysis of BACT for nitrogen oxide for the coker heater?
A Yes.
Q In reviewing that analysis, did you look at any other facilities employing selective catalytic reduction for coker heaters?
A Yes.
Q I want to turn to Exhibit JE-1, page 000133. I believe there is a table on this page. What does this table show?
A So, yes, there is a table. The heading of Table 1, NOx and Carbon Monoxide BACT for Coker Heaters, and there is a list of facilities and where they're from and what they've used as BACT.
Q Are these some of the other facilities you considered?
A Yes.
Q So I want to take them in the order listed.
A I should qualify. Not what they used as BACT, but what they consider as BACT and different technologies out

there.
Q So did any of these facilities use selective catalytic reduction as BACT?
A Yes.
Q Which one?
A The first two on the list, Tesoro - Martinez and Shell - Martinez, both in California. The third one is pronounced as Total Refining, that would be Port Arthur, Texas. The fourth one down on this list is Marathon Garyville Refinery in Louisiana. And at the very bottom is reference to the Flint Hill Resources - Pine Bend facility in Minnesota.
Q Did these facilities -- they employed SCR, it looks like; is that right?
A Yes.
Q Did they employ SCR as BACT?
A I believe one of them did. I forget how many. Some of them employed SCR, as I understand it, for other reasons than BACT.
Q Okay. I want to go down through these one at a time in the order they're listed here. The first one is Tesoro - Martinez. Was SCR required as BACT in the Tesoro - Martinez facility?
A My understanding is that it was required under the LAER program, the third new source review program after PSD

major program, minor program, and the non-attainment is another new source review major program. And under that, they are required to lowest achievable emission rate technology and my understanding is that's why they employed SCR.
Q Why would they have been required to use LAER?
A Because they are located in a non-attainment area.
Q How about Shell - Martinez?
A Same reason there.
Q So Shell used SCR as LAER?
A Yes.
Q Because they were in a non-attainment area?
A That's correct.
Q How about Total Refining, I guess it's Total Refining, in Port Arthur, Texas.
A So at the time of their project construction, my understanding is that they were in non-attainment for ozone and so similar situation, using -- let's see, 2008 or '10 -- if you look at the EPA website of non-attainment areas and the times they were considered non-attainment, the start of that project coincides with the time period that they were still in non-attainment for, I believe, ozone.
Q And how about the Marathon - Garyville, Louisiana facility, was SCR required as BACT?

A So it's listed as a technology used at the facility, but specifically -- well, says that could have been rejected as BACT due to its cost economic impact analysis.
Q Could you turn to Ecology Exhibit Number 10.
A Okay.
Q Do you recognize this document?
A Yes.
Q What is it?
A So this is from the Department of Environmental Quality, State of Louisiana. It's with respect to PSD permit and this is a cover letter of the permit itself for that facility.
Q Does it say anything about the cost for BACT for SCR in this letter?
A It does.
Q Where is that?
A Second page of the exhibit, I guess it's listed as page 5 and I guess the fourth paragraph from the bottom of the page, it discusses that the facility is voluntarily installing selective catalytic reduction in addition to ultra-low NOx burners, and it goes on to talk about some other equipment. And then it says at the last sentence of this paragraph, it says, SCRs could have been rejected on the basis of economical infeasibility, and then provided a range of $10,000 to $73,000 per ton of

NOx reduced based on heater size.

MS. SHIREY: So I ask the board to admit Ecology Exhibit 10 into evidence.

MR. WISE: Any objection?

MS. BRIMMER: No objection.

MR. WISE: Exhibit 10 is admitted.

(R-ECY-10 admitted.)

Q (By Ms. Shirey): So the next facility on the list in this table on JE000133 I believe is Flint Hills, Minnesota. What can you tell me about Flint Hills, Minnesota?

A They have installed SCR on their coker heater and I tried to find a cost analysis for this facility. I personally called up, found the engineer's name, but I don't recall at the moment, and I called him up on the telephone and I asked him if a cost analysis had been done, and he was not aware of one.

Q So, first of all, is there one project or two?

A I believe this was the second project. There were two projects. The second one, I believe, is this one.

Q Was SCR required as BACT for either of those projects?

A Yes, they list it as BACT, but as I said, apparently no cost analysis.

Q How about the first project?

A I'm not sure if the first project had been started yet

at the time of this application, I don't know.
Q So there were two projects?
A I don't know if the second one had been started.
Q So which of the two projects were you discussing just now?
A I understood it to be the second one. The numbering system is a little confusing from their website, but talking to the permit engineer, I could be wrong, but, anyway, they didn't have a cost analysis.
Q Did you look at any other facilities?
A Yes.
Q Do you know which other ones you looked at?
A There was one in Arizona, I believe one in North Dakota, I believe an Indiana facility, and I might be missing one.
Q So I'd ask you to turn to Ecology Exhibit 11. Do you recognize this document?
A Yes, I do.
Q What is this document?
A So I mentioned a North Dakota facility and this is a great support document for that facility called the Davis Refinery in Billings County, North Dakota.
Q And does it say anything about installing SCR?
A My recollection of looking at this was that whatever controls they had planned, coker heaters were not listed

as the units that they planned to install. As far as SCR, I don't know if -- all I know is they didn't have any plans to put in a coker unit is what sticks out for me for this facility.

Q Was this a PSD permit application?

A Oh, it's a minor, yeah, so they were a synthetic minor trying to get out of major permitting.

Q So I wonder if you'd turn -- I think that's where you are. Are you at page 4 of this?

A Yes.

Q And if you look at the last sentence of the last paragraph, what does that say?

MS. BRIMMER: I'm sorry, which one is page 4? Is it sheet 4 at the top?

THE WITNESS: Yeah, I wasn't sure either.

MS. SHIREY: I'm sorry, I'm sorry. That's my fault. The bottom of the page says page 4 of 8 under Ecology. No wonder you don't know what I'm talking about. It's the fourth page if you count the pages.

MS. BRIMMER: Do you start with this one as 1?

MS. SHIREY: Yeah.

A And could you repeat the question.

Q (By Ms. Shirey): So the last paragraph on that page, the last sentence, what does that say?
A "Since formal BACT analysis is not required, analysis for energy, environment and economic impacts was not conducted for proposed emission controls."
Q So what does that mean in terms of cost analysis?
A So a cost analysis was not prepared.
MS. SHIREY: I'd ask the board to admit Ecology Exhibit 11.
MR. WISE: Any objections?
MS. BRIMMER: No objection.
MR. WISE: Ecology Exhibit 11 is admitted.
(R-ECY-11 admitted.)
Q (By Ms. Shirey): Would you turn to Ecology Exhibit 12.
A Okay.
Q And what is this document?
A This is a technical support document and statement of basis for construction of a facility in Arizona called Arizona Clean Fuels Yuma, LLC, Petroleum Refinery, dated September of 2006.
Q What can you tell me about this project?
A My understanding, I believe still to be true, to date it has not been built.
Q Is there anything else you can tell me?

A My understanding is that the facility has not been built. It's as if the permit never existed, I've heard that language mentioned by others, but in any case, it was not built.
Q Were they implementing SCR on the coker heaters?
A I believe that was in the permit, yes.
Q So if you'd turn to page 170 of 347.
A Okay.
Q And there is a table on that page. Do you see that?
A Yes.
Q And does that table include delayed coking unit charge heaters?
A Yes, the last row in that table.
Q So can you tell me what the NOx emission controls BACT was going to be for these units?
A So they list a limit of .030 pounds of NOx per million BTU heat input.
Q And does the discussion of this say anything about what that means in terms of emission controls?
A I don't see that here unless I'm missing it. Well, okay, here it is. Yeah, low Nox burners.
Q Where do you see that?
A That would be the paragraph above the table.
Q And where are you looking in that paragraph?
A The first sentence of the second paragraph.

Q So looks like they were not going to be implementing selective catalytic reduction on the coker heaters.
A I don't see it listed here. The previous page discusses SCR, but it's not on this page here, you're right.
Q So what was BACT for the delayed coking units here, the heaters?
A So I'll need to go back to the previous page. Are you still on 170 or can I go to 169?
Q You can go to 169, you can go wherever you need to.
A And would you repeat the question, please.
Q What was required as BACT for the coker heaters on this project?
A Okay. "The department agrees that the permittee's proposal generally represents BACT for NOx emissions for these process heaters," and they go on to describe SCR and a provision for conducting SCR performance demonstrations study, which tells me that they didn't know if it could be demonstrated for this facility, in which case, the facility was never built, so it wasn't demonstrated.
Q Is that discussion talking about the -- I'm just going to skip over this one for now. Sounds like you haven't looked at this in awhile, so --
A So we wrote this one off early when we found out that the facility was never built. You're done then, don't

need to consider a facility that wasn't built. So, no, I admit I didn't spend a lot of time evaluating this nonexistent facility.

Q All right. You said you also looked at the BP Whiting facility. What did you find out about that?

A I have to make sure I get my facilities right. I believe that's the one in Indiana, in a non-attainment area, near Gary, Indiana, in Lake County, northwest corner of the state, and that's a non-attainment area, so they used LAER, they were required to use LAER there.

Q Would you turn to Ecology Exhibit 13.

A Yes.

Q So do you recognize this document?

A Yes, I do.

Q What is it this?

A So this is a document I found researching this facility going to the state of Indiana is where I found it, Indiana Department of Environmental Management, and it shows the non-attainment areas in the state, and as you can see in the top left corner are two counties, one of which is Lake County, which is where the Whiting facility is located, and the bottom of this page it explains that it is in fact a non-attainment area for eight-hour ozone standard.

Q And what does that mean in terms of nitrogen oxide

emissions?
A So they require to employ, in a project that triggers non-attainment threshold, they're required to employ lowest achievable emission rate technology.
Q Even though it's a non-attainment for ozone and not NOx?
A That's correct. They look at VOCs and NOx whenever you have ozone NOx and VOCs come into play.
Q And why is that?
A They lead to the formation of ozone.
Q Okay.
MS. SHIREY: I would ask that Ecology Exhibit 13 be admitted.
MR. WISE: Any objection?
MS. POWER: No.
MS. BRIMMER: No.
MR. WISE: Ecology Exhibit 13 is admitted.
(R-ECY-13 admitted.)
Q (By Ms. Shirey): So if I have counted correctly, it looks like you reviewed eight facilities. Does that sound about right?
A Sounds about right.
Q And there were two projects at one of them, so nine projects. So out of those nine projects, did any require SCR as BACT for coker heaters?

A Yes, some of them did, a few of them did, they listed SCR as BACT.

Q Can you go back. So you told me that --

A The Flint Hills facility listed SCR as BACT, but that was the one that had no cost analysis.

Q Which one?

A The Flint Hills, Minnesota.

Q Any of the other ones?

A Garyville said it was voluntarily listed. Could have been rejected. I don't recall if they considered that BACT or not. Could have been rejected, but it looks like they considered that BACT.

Q But did Garyville employ it as BACT or did they put it on voluntarily?

A They put it on voluntarily, that's right. If you're asking if BACT was required for them to put SCR, the answer is no, if that's what you're asking.

Q And BP - Whiting, was it BACT?

A No. I mean, that's correct, that was a non-attainment area triggered the SCR.

Q And at the Arizona facility?

A Like I said, the facility that was never built.

Q Flint Hills, you said one of them required as BACT?

A Yes.

Q How about the Total, Texas, was that required as BACT?

A That would be LAER.
Q And Marathon, Shell - Martinez?
A Same, LAER required.
Q And Tesoro - Martinez?
A And that would also be LAER.
Q So I think you only named one that was actually where BACT was required; is that right?
A It's listed as BACT without a cost analysis. I believe that's the only one.
Q Okay. Do you know of any other places where selective catalytic reduction has been required as BACT for coker heaters?
A For coker heaters, no.
Q Does EPA guidance say anything about how to evaluate a technology that has not been required as BACT or that has rarely been required as BACT?
A Does it say anything? Yes.
Q I want to turn to Joint Exhibit 12. Do you recognize this exhibit, Joint Exhibit 12?
A Yes. It's the 1990 New Source Review Workshop Manual, Draft, dated October 1990.
Q I want you to turn -- actually, did you hear Al Newman's testimony on this?
A I did.
Q And did he read a portion of this that talked about what

you do when a technology has not been required as BACT or has rarely been required as BACT, do you remember that?
A I believe he read some things; I don't remember exactly.
Q Okay. If you would turn to page 3.45.
A Okay.
Q And in the middle paragraph on that page, the sentence beginning "Specifically."
A Okay.
Q So what does it say there?
A "Specifically, the applicant should document that the cost to the applicant of the control alternative is significantly beyond the range of recent costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant."
Q So I want to turn to Ecology Exhibit 9.
A Okay.
Q Do you recognize this document?
A Yes, I do.
Q Did you help prepare this document?
A Yes, I did.
Q So what is it?
A It's a list of recent BACT determinations for the specific pollutant NOx by the Department of Ecology.
Q And what does it show about cost that Ecology has

rejected -- for costs where Ecology has rejected the control for NOx?
A What the costs are?
Q Yeah.
A It shows costs ranging from approximately 11,600 on up to 65,000 that were all rejected based on economic analysis of being too costly.
Q What does it show about costs that have been accepted as BACT?
A It shows that costs were not calculated for the accepted option.
Q And why was that?
A It's conceivable you could have costs for -- in this case, the next one down, and they just accepted that as BACT and they didn't do a cost analysis to try to get out of it, so to speak.
Q Does that mean that cost analyses are often or normally done to disqualify a technology as BACT?
A Yes, it does.
Q I want to turn to Exhibit R-38, and that's going to be in BP's exhibit book, the white one.
A Which number?
Q R-38.
A Okay.
Q What is this document?

A This is a cost analysis that has Ramboll's name on it as BP's consultant for the BP coker heater equipped with an SCR, dated April 4, 2018.

Q So this would be BP's corrected cost analysis, is that right, correcting for the error that they found that they had earlier been comparing the costs of two SCRs to the benefits of one; is that right?

A Yes, that's my understanding.

Q So what is the cost effectiveness number on this document?

A So there's two columns provided. The lowest cost on the page is $12,361 per ton of NOx removed.

Q So does that change your opinion about whether SCR should be BACT in this case?

A No, it does not.

Q So did this come as a surprise to you that BP's earlier cost effectiveness analysis evaluated as SCR evaluated costs for two SCR units and emissions from just one?

A Yes.

Q Was there anything in BP's 2016 permit application that indicated that the cost analyses were looking at costs for two SCRs?

A If there was, I missed it.

Q So did you see anything?

A I did not.

Q All right. When you got this updated analysis, did you question it at all?
A The whole analysis or a specific part?
Q No, the whole thing.
A I did.
Q So what did you question?
A That they had used a higher ammonia reagent value cost per pound previously and now it's dropped significantly from before, so I looked into -- I questioned that initially.
Q And what did you find?
A The price of ammonia has changed; it bounces around a lot. If an applicant comes and says the price of ammonia is double the last three years and gone back, moved around a lot, we provide some latitude in what cost for ammonia they we would propose, because, remember, we're looking at a 25-year period. I looked back, I think, the last four and half years from when the project started and I found costs up to maybe 35 cents a pound, and you go back a little further, you could find maybe 38 cents a pound. I think they reached 45 cents a pound prior to that. So I would have been willing to accept a slightly higher cost, to be honest, because of the way the price has bounced around, but consistent with them, BP tends to be conservative,

although, they missed that and I did, too, at the double counting of the SCR. Other than that, they tend to overestimate, which is helpful to an engineer when you know the applicant is overestimating emissions, so if they make a mistake like this, as you can see, they're still above our back threshold.

Q Okay. I want to take a little bit closer look at the costs in this analysis. What does the analysis show is the annual interest rate?

A Seven percent.

Q Do you agree that that is appropriate for this project?

A My understanding is, yes, it is.

Q And why is that?

A They list the reference to the cost manual.

Q So did you hear the discussion earlier today about interest rates with Alan Newman?

A I did.

Q Do you agree with Mr. Newman about 7 percent interest rates?

A I do.

Q And have you been trained on how to do these analyses?

A I haven't been in the Department of Ecology as long as he has, but when I see a default value in a cost manual, that's okay; as far as I'm concerned, it's a usable number.

Q All right. So what does this document show about the contingency rate?
A I believe it says 15 percent. I haven't found it yet, but I'm pretty sure that's here somewhere. I'm not seeing it, but I do recall -- okay, there it is, it's 15 percent.
Q In paragraph 78 of his prefiled testimony, Dr. Sahu claims that the contingency rate should have been 5 percent rather than 15 percent. Do you agree with that?
A No, I do not.
Q Why not?
A BP started with a facility-specific contingency factor of 30 percent. They wanted to err on the side of the EPA manual. Once again, as a permit engineer, I appreciate some consistency there, but referring back to the cost manual, it's 15 percent.
Q So in paragraphs 52 and 54 of his prefiled testimony, Dr. Sahu claims that BP's cost analysis improperly evaluates incremental cost effectiveness rather than average cost effectiveness. Can you talk a little bit about what is average cost effectiveness and what is incremental cost effectiveness?
A Sure. And I had conversations with the BP engineer at the time, when Scott Inloes was the engineer, and I believe also with Colleen Kemp, and discussed using an

average cost analysis, not incremental, and doing some research, the Puzzle Book says you can use the average cost or incremental cost, but if you're going to use incremental cost, you have to use it with some other support, whereas, if you use an average cost, that alone can stand.

Quite often, you'll see both. Some people supplement the incremental cost with an average cost, and that's in compliance with the Puzzle Book. There was a challenge, I believe, at some time in the past where someone, some facility, tried to use an incremental cost by itself, or someone said you cannot use an incremental cost at all, but they lost, you can use it, but as I just said, if you're going to use a incremental cost, you have to have something with it, and most of time, that's an average cost, and as I said, you may have an average cost all by itself.

In this case, BP provided both costs for almost every technology they looked at, every cost analysis they looked at, and never did they rely on an incremental cost in and of itself by itself.

Q How do you evaluate average cost effectiveness?

A Instead of looking at comparison between two control technology alternatives, which would be an incremental cost, you look at total tons removed between the

inherent-based technology and the cost for that in tons removed.
Q And what do you do with an incremental cost effectiveness evaluation?
A That would be just comparing two different control technologies and the cost between them.
Q In your opinion, is this cost analysis in Exhibit R-38, is that an average cost analysis or incremental cost analysis?
A Average.
Q And why do you say that?
A Because they aren't comparing this technology to what I believe now is inherent-based technology.
Q And by that, do you mean the alternative NOx burners?
A Yes.
Q I want to turn to EPA's guidance again, JE-12, at page B-37, which is JE001335.
A I am sorry, could you say that again.
Q JE001335.
A Of which exhibit?
Q Joint Exhibit 12. I think you're in wrong book.
A I'm in 12 and could you repeat the page number one more time.
Q 001335.
A Okay.

Q So I believe on this page it says that, in doing a cost effectiveness analysis, you can't set your baseline as emissions controls necessary to meet new source performance standards. Is that what that says?
A Yes.
Q And are ultra-low NOx burners, do they meet new source performance standards in this case?
A They do.
Q So does that make BP's analysis wrong?
A I don't believe so.
Q And why not?
A Initially, going back to August of 2016, this issue was brought up by the EPA and emailed to the Northwest Clean Air Agency, which is the agency that will enforce this permit, Title V permit. So looking at this 1990 Workshop Guidance Manual, it provides some other options. It says you can take historically higher upper bound as an option. That was the first option that was jumped on and we stuck with that option.
There are other considerations to look at, which BP did. They insisted all along that just, coincidentally, it's the same as the new source performance standard, but to avoid an appearance of trying to err on the side of being conservative, you know, our approach, so we forced them to use an

historical upper bound, which I think acknowledging using historical upper bound, you are talking about the heaters that are going to be removed and that doesn't make much sense if you're going to install new heaters.

So we're now aware of more documents that support the case that ultra-low NOx burners are the inherently lower based technology from which to look at your BACT cost analysis.

Q I want to slow down just a bit. So on that page that you've got with the page B-37 in the EPA Cost Manual, I'm sorry, EPA's PSD manual, does it mention inherently lower pollutant processes somewhere?

A I believe it does. The last paragraph, there is a little bit of an odd -- one-word sentence, a one line that just has a word in it. I'll start before there. It says, "Estimating a realistic upper-bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source."

Q I'm going to stop you a minute and look at the paragraph above that. The sentence that starts, "When calculating the cost effectiveness."

A Okay.

Q What does that say?
A It says, "When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself."
Q Okay. So if I'm understanding right, you started out by thinking you could look at the upper bound?
A Yes.
Q And then you found that you were convinced that BP could take -- that the baseline could be assumed to be the emissions from the lower emitting process itself, if I understood you right?
A Yes.
Q Have you seen any EPA guidance letters on this?
A Yes, I have.
Q I wonder if you could turn to Exhibit R-14. That's BP's book.
A I have it.
Q R-14. Are you there?
A Yes.
Q Do you recognize this document?
A Yes, I do.
Q What is it?
A It's a fact sheet for a facility called the Palmdale

Energy Project and Fact Sheet for a permit dated August -- the fact sheet is dated August 2017.

Q I believe that this exhibit has already been admitted. It was discussed yesterday by one of BP's witnesses. So if you turn to page 36, what does this document say -- at the top of 37, I think, what does it say about ultra-low NOx burners?

A The first paragraph?

Q Yes.

A It says, "The applicant submitted a cost analysis demonstrating that SCR is not cost effective for the" facility's "auxiliary boiler. The applicant estimated the cost effectiveness at $58,100 per ton of NOx removed. However, in conducting this analysis, the applicant looked at the cost of reducing NOx from the incremental cost range of going from 9 parts per million using ultra-low NOx burners instead of the total cost effectiveness from the base case. We agree that when calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, in this case, ultra-low NOx burners, baseline emissions may be assumed to be the emissions from the lower polluting process itself."

Q Okay. So when you saw this guidance, did that change your thinking at all?

A It did. Our thinking was always that it was a little bogus to use a technology that's going away, the control creator's upper bound, historical upper bound, is going away just because it's coincidentally the same as an NSPS.
Q You got to stop a minute, because what's the same?
A Oh, the proposed limit of the ultra-low NOx burner, capacity of the burner, matches new source performance standard.
Q And so what were you saying about that?
A So on that basis alone, we were erring on the side you can't do this, let's not do that, let's make them use the historical upper bounds. That's what we did until now. It's pretty clear that ultra-low NOx burners are the inherently lower baseline technology and you can use that itself. It justifies not doing the approach that we forced BP to do.
Q So I want to turn to Exhibit JE-1 at page JE000156.
A Okay. Could you repeat the reference.
Q JE000156.
A Of Exhibit 1, correct. I am there.
Q Do you recognize this document?
A I do.
Q What is this?
A This was initial BACT cost analysis that BP provided to

us for SCR use for the coker heaters.
Q And what is the cost effectiveness number on this document?
A It is $39,500 per ton.
Q And when you got questions about the baseline on this document, what did you do, the baseline emissions for this document?
A I continued conversations that we had started with the Northwest Clean Air Agency back in August 2016 and I converted this number using historical upper bound value.
Q What do you mean by you converted the number?
A So instead of using NSPS baseline case as they list there, which is .06 pounds of NOx per million BTU, we used a recent test provided by the Northwest Clean Air Agency, a test result, which was, I believe, first test result was .074 pounds of NOx per million BTU, and we substituted the .074 for the .06 that's in the line near the bottom, fourth line from the bottom. The first row under "Cost Effectiveness," you will see a 303 million BTU per hour, and right after that is .06 pounds NOx million BTU number that I just referred to that we substituted with the .074 pounds per NOx per million BTU provided from the Northwest Clean Air Agency.
Q And that number came from two tests I think you said?

A I think the first one was -- I think just one test or most recent test at that time, I believe.
Q Okay. Could you turn to Ecology Exhibit 14.
A Okay.
Q Do you recognize this document?
A Yes, I do.
Q And so what is it?
A It includes the conversion I just mentioned along with the reference to the Northwest Clean Air Agency email that I also referenced.
Q Did you prepare these calculations?
A This first page is calculations I did, Northwest Clean Air Agency's calculations they did provide, but it's listed in the email that matches the number that I came up with.
MS. SHIREY: Okay. I'm going to ask to get Ecology Exhibit 14 admitted.
MR. WISE: Any objections?
MS. BRIMMER: No objection.
MR. WISE: Ecology Exhibit 14 is admitted.
(R-ECY-14 admitted.)
Q (By Ms. Shirey): So now do you think that the way you did this recalculation was correct?
A I mean, it is correct.

Q I guess I didn't ask that right. Do you think that this recalculation is the correct way to determine the baseline in this case?
A I don't think it's the best way; I don't think it's the most accurate way.
Q What is the best way?
A Since the old coker heaters will be removed, referencing emissions from it seems not as accurate as referencing the new technology, which is the new coker heater ultra-low NOx burner.
Q Okay. So looking back at BP Exhibit R-38, the recalculated BACT cost analysis.
A You said Ecology?
Q I'm sorry, R-38, it's the BP document.
A Okay.
Q So did you do a revised baseline analysis for this particular version of the cost analysis, using the baseline you used for your recalculations of the earlier BACT analysis?
A I believe I did. It's not shown here.
Q So what did you find?
A I think it came to 11,700 or eight hundred. I can't remember the exact number. And I played around with the ammonia number, like I said, on my own, say 33 cents a pound, might be willing to accept 35. Anyway, it was

around 11,000, 12,000 range, closer to 12,000.
Q Okay. So is that document with that calculation, is that one of the exhibits that Ecology has provided for this hearing?
A This one here?
Q No, the one, your recalculation that you were just describing.
A I don't know if it has.
Q I'll tell you it hasn't.
A Okay.
Q So why would we not have provided that?
A Okay. We are convinced now that the approach of doing that, using the historical upper bound, is not the best, although, justified by the Puzzle Book, it's just not appropriate for technology that's going away compared to new information and newer technology, and in light of the fact that it is justified by guidance documents to be the inherently baseline technology.
Q So do you still believe that selective catalytic reduction is not cost effective as BACT for the new coker heaters at BP?
A I do.

MS. SHIREY: I just noticed we're almost at 4:30, and this is a reasonable stopping point, unless you want to keep going.

MR. WISE: I think we'll have to come back tomorrow anyway and I am a little concerned about State Parks' tolerance, so why don't we go ahead and stop today and then we'll start at 9:00 in the morning and finish this up.

MS. BRIMMER: Could I ask a housekeeping question. And I don't know if you need this on the record or not, I'll let you decide. I just want to make sure that I have an understanding, if I could, of how much longer Mr. Huitsing's direct is so that I just have adequate time to do a little bit of cleanup rebuttal at the very end.

MR. WISE: Okay. Ms. Shirey, do you have any idea how much longer?

MS. SHIREY: I can tell you I didn't think it was going to take nearly this long, so -- I thought we'd be done by now. I'm about three quarters of the way through, so --

MS. BRIMMER: My estimate is then that we'll probably finish with Mr. Huitsing at least by noon, so that that would leave time for rebuttal.

MR. WISE: Yeah, hopefully.

MS. POWER: Your Honor, I would just note that to the extent that there is rebuttal, that we ask that it be very limited because all of the expert testimony was prefiled in this case, and so with respect to rebuttal, it should, in fact, truly be something new that has come out within the hearing that we would expect rebuttal testimony on.

MR. WISE: Yes, I agree, it should address new things that have come up during the hearing.

MS. BRIMMER: There's been quite a bit, so yes.

MR. WISE: Okay. We'll see you tomorrow.

(The hearing recessed at 4:30 p.m. to resume April 27, 2018, at 9:00 a.m.)

C E R T I F I C A T E

STATE OF WASHINGTON)
) ss
COUNTY OF THURSTON )

I, KIM L. OTIS, a Certified Court Reporter in and for the State of Washington, residing at Olympia, do hereby certify;

That the foregoing proceedings were taken before me and thereafter reduced to a typed format under my direction; that the transcript is a full, true and complete transcript of said proceedings consisting of Pages 675 through 905.

That as a CCR in this state, I am bound by the Rules of Conduct as Codified in WAC 308-14-130; that court reporting arrangements and fees in this case are offered to all parties on equal terms.

That I am not a relative, employee, attorney or counsel of any party to this action, or relative or employee of any such attorney or counsel, and I am not financially interested in said action or the outcome thereof;

IN WITNESS WHEREOF, I have hereunto set my hand this 18th day of June, 2018.

Kim L. Otis, CCR No. 2342

BEFORE THE AIR QUALITY CONTROL COMMISSION
STATE OF COLORADO

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IN THE MATTER OF PROPOSED REVISIONS TO REGULATION NUMBER 23
NOVEMBER 17 to 19, 2021 HEARING

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**PREHEARING STATEMENT OF THE COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT, AIR POLLUTION CONTROL DIVISION**

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The Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") hereby submits its Prehearing Statement ("PHS") in this matter, discussing the policy, factual, and legal grounds for the proposed revisions to Regulation Number 23 which addresses Colorado's obligations related to regional haze.

# I. EXECUTIVE SUMMARY

## A. Summary of Proposal

The Division is proposing revisions to Regulation Number 23 to address Colorado's obligations related to Regional Haze, as directed by § 25-7-211, C.R.S. These revisions are expected to also achieve the co-benefit of reducing greenhouse gases ("GHGs") contingent upon Public Utility Commission ("PUC") approval of electric generating unit ("EGU") closures and generator fuel switching proposed in pending resource plans, as directed by SB 19-096,[1] HB 19-1261,[2] and HB 21-1266,[3] and are consistent with SB 19-236.[4] The proposed revisions complete the second phase of the Regional Haze rulemaking process for those sources identified during the initial screening process that were not addressed during the phase 1 rulemaking conducted in 2020.

The U.S. Environmental Protection Agency ("EPA") promulgated the Regional Haze rule in 1999, and subsequently revised it in 2017, which requires each state to reduce

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[1] SB 19-096, Concerning the Collection of Greenhouse Gas Emissions Data to Facilitate the Implementation of Measures that Would Most Cost-Effectively Allow the State to Meet Its Greenhouse Gas Emissions Reduction Goals, and, in Connection Therewith, Making an Appropriation, 72nd Gen. Assemb., 1st Reg. Sess. (Colo. 2019) (codified as § 25-7-140 C.R.S.).
[2] HB 19-1261, Concerning the Reduction of Greenhouse Gas Pollution, and, in Connection Therewith, Establishing Statewide Greenhouse Gas Pollution Reduction Goals and Making an Appropriation, 72nd Gen. Assemb., 1st Reg. Sess. (Colo. 2019) (codified as §§ 25-7-102, -103, -105, C.R.S.).
[3] HB 21-1266, Concerning Efforts to Redress the Effects of Environmental Injustice on Disproportionately Impacted Communities, and, in Connection Therewith, Making an Appropriation, 73rd Gen. Assemb., 1st Reg. Sess. (Colo. 2021) (relevant portions codified as §§ 24-4-109, 25-7-105, C.R.S.) ("HB 21-1266").
[4] SB 19-236, Concerning the Continuation of the Public Utilities Commission, and, in Connection Therewith, Implementing the Recommendations Contained in the 2018 Sunset Report by the Department of Regulatory Agencies and Making an Appropriation, 72nd Gen. Assemb., 1st Reg. Sess. (Colo. 2019) (relevant portions codified as §§ 40-2-124, -125.5) ("SB 19-236").

emissions of visibility impairing pollutants that negatively impact class I areas and incorporate any necessary emission reductions in a state implementation plan (SIP) to address Regional Haze.[5] Regional haze is visibility impairment caused by multiple emission sources over a broad geographic area. The Regional Haze Rule aims to continue progress towards improving visibility at the 156 mandatory class I areas nationwide for the most impaired days and maintain the best visibility for the clearest days. Colorado has twelve class I areas (four national parks and eight wilderness areas) at which visibility must be evaluated. EPA intended that the Regional Haze rule be evaluated periodically over a period of 60 years with a goal of achieving natural visibility conditions by 2064.

During the first implementation period, often referred to as round 1, states were required to establish Best Available Retrofit Technology ("BART") and Reasonable Progress ("RP") requirements. Colorado accomplished this with two separate SIP submittals to EPA in 2008 and 2009, and subsequently adopted revisions in 2011, 2014, and 2016. EPA approved Colorado's Regional Haze SIP in several actions, last approved on July 5, 2018.[6]

During this second implementation period (aka round 2), states must evaluate their progress in meeting natural visibility conditions in class I areas and submit a SIP revision to EPA by July 31, 2021. Colorado has historically, and continues, to collaborate with other western states and EPA through the Western Regional Air Partnership ("WRAP") to develop the necessary data products to support the second 10-year planning period Regional Haze SIP, including emission inventories, meteorological weighted emission impact analyses, particulate matter ("PM") source apportionment, and visibility modeling. During round 2, however, the complexity of the Regional Haze technical analysis coupled with coordination among so many states, tribes, federal land managers ("FLMs"), and EPA has produced delays in the release of some of the data products that are instrumental to completing the Regional Haze SIP. Final data products were just recently completed from this coordinated process.

The delay in necessary data and modeling products has significant implications for several states, including Colorado, in meeting the round 2 SIP submittal due date. While Colorado has actively worked to timely evaluate potential emission reduction strategies for stationary sources, Colorado could not fully evaluate progress against the visibility goals without all of the modeling and data analysis products. This delay also created challenges for Colorado to satisfy FLM consultation directives, provide information to stakeholders, and finalize the analyses to be included in the SIP. Further, Colorado's rulemaking process itself demands at least a three-month timeframe in addition to a required legislative review process for any SIP submittal. All of this means that Colorado was not able to fully address all SIP requirements and submit the round 2 SIP to EPA by the July 31, 2021 due date. EPA is aware of these challenges and has been notified of the delay in submittal.

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[5] *See* 40 CFR §§ 51.300-51.309.

[6] Approval and Promulgation of Air Quality Implementation Plans; Colorado; Regional Haze State Implementation Plan, 83 Fed. Reg. 31332 (July 5, 2018).

Additionally, EPA issued a Regional Haze clarification memo on July 8, 2021,[7] only 23 days before the due date for the round 2 SIP submissions. While Colorado believes that the technical analyses, rule proposal, and SIP revisions are aligned with the EPA Regional Haze clarification memo, the timing of its release does not allow for substantial changes in the planning process or SIP adoption proposed for consideration before the Air Quality Control Commission without creating significant delays (well beyond the SIP due date of July 31, 2021), requiring additional or new analyses, and elevating the risk of a Federal Implementation Plan being imposed upon Colorado.

The Division has not proposed any unit retirements, fuel switching, or changes to permitted fuel consumption limits as a RP control strategy. Therefore, no proposed control strategies for this Regional Haze SIP revision can be stated to directly reduce GHG emissions. However, the proposed revisions are expected to achieve the additional co-benefit of reducing GHG emissions contingent upon PUC approval of the proposed EGU closure and fuel switching dates in Public Service Company of Colorado's ("PSCo") pending Electric Resource Plan/Clean Energy Plan, docket number 21A-0141E. In HB 19-1261, the General Assembly declared that "[c]limate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life[,]" acknowledged that "Colorado is already experiencing harmful climate impacts[,]" and that "[m]any of these impacts disproportionately affect" certain disadvantaged communities.[8] Colorado's statewide GHG reduction goals require the Commission to implement regulations to achieve a 26% reduction of statewide GHG emissions by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels.[9] HB 21-1266 further clarified timelines for electric generating utilities to submit Clean Energy Plans and placed additional GHG reduction requirements on the industrial sector, which also affects sources subject to this phase 2 rulemaking. To clarify, this phase 2 rulemaking addresses Regional Haze SIP requirements under the Clean Air Act, while achieving GHG co-benefits. The data collection, development, and evaluation of the first Clean Energy Plan is currently underway.[10] The development of rules to achieve industrial GHG reductions is being conducted simultaneously with this regional haze rulemaking process and emissions reductions are quantified in the Final Economic Impact Analysis.

Colorado continues to separately develop GHG emission reduction strategies to address these objectives and statutorily mandated reduction goals. The potential EGU

[7] APCD_PHS_EX-012 (Memorandum from Peter Tsirigotis, Director, EPA, to Regional Air Division Directors, Regions 1-10 (July 8, 2021)).
[8] § 25-7-102, C.R.S.
[9] § 25-7-102(g), C.R.S.
[10] *See* SB 19-236. Section 40-2-125.5(4)(a) requires PSCo, a "qualifying retail utility" as defined in statute, to file the first electric resource plan that includes a clean energy plan outlining how PSCo intends to achieve the clean energy targets established in § 40-2-125.5(3). This is currently under review at the PUC in Docket No. 21A-0141E. Other utilities have announced their intent to voluntarily submit Clean Energy Plans in the near future.

retirements and fuel switching aid in securing timely and significant GHG reductions and require an analysis of the social cost of greenhouse gases pursuant to § 25-7-105(1)(e), C.R.S.

In HB 21-1266, signed into law on July 2, 2021, the General Assembly, determined that "[s]tate action to correct environmental injustice is imperative, and state policy can and should improve public health and the environment and improve the overall well-being of all communities... [and that e]fforts to right past wrongs and move toward environmental justice must focus on disproportionately impacted communities and the voices of their residents."[11] Thus, the state must meaningfully engage disproportionately impacted communities as partners and stakeholders in government decision-making, especially when evaluating potential environmental and climate threats to these communities. The Division has endeavored to meaningfully engage with these communities even though the vast majority of outreach and planning for this rule began more than two years ago, long before the establishment of HB 21-1266 just three months ago.

## B. History of Rulemaking Stakeholder Process

The Division held six regional haze public meetings on June 10, August 1, October 3, 2019, January 9, March 27, and July 28, 2020. The Division also met with the FLM agencies in June 2019 and in August and October 2020 in preparation for the phase 1 hearing.

Specific to its August 2021 rulemaking proposal for this universe of regulated sources being considered in phase 2, the Division held public listening sessions on January 7 and February 10, 2021 with the North Denver area communities; March 4 and March 11, 2021 with the Pueblo area communities; and August 10 via Zoom platform to discuss the upcoming proposal. The Division has also participated in ongoing WRAP meetings, held meetings with FLM agencies in April, May, and June 2021 to discuss SIP progress and technical analyses, and also met with other state agencies, EPA Region 8 staff, and stakeholders subject to this rulemaking.

Since submitting its request for hearing to the Commission, the Division has met regularly and often with stakeholders, which has resulted in identifying primary issues as well as changes to the Request Proposal as described in this Prehearing Statement and as included in the PHS Proposal. The Division will further continue its efforts in coordinating with stakeholders to narrow the contested issues to be heard by the Commission in November.

[11] HB 21-1266, § 2(IV).

## C. Contents of Prehearing Statement

This Prehearing Statement contains the following:



## D. Summary of Exhibits

On the APCD PHS Exhibit List enclosed with this Prehearing Statement, the Division has identified potential exhibits in support of its petition for rulemaking in addition to citations provided in this Prehearing Statement. The Division's exhibits include documents and data used to support its compliance with federal and state regulations, data submitted to or collected by the Division to administer its air quality program, and studies and reports relating to the proposed rules. The Division is also submitting the current proposed revisions to Regulation Number 23, along with a revised Statement of Basis and Purpose and Final Economic Impact Analysis.

Many of the Division's exhibits are cited in this Prehearing Statement as support for specific positions; however, a citation to one exhibit is not intended to preclude the Division's reliance on another exhibit for the same position. Further, not all exhibits are cited specifically in this Prehearing Statement but represent the collection of studies and data relied upon to prepare this proposal. The Division will supplement its exhibits to respond to other Parties' prehearing statements, as necessary.

## E. Estimate of Time Necessary for Presentation

The Division estimates that it will require approximately 3.5 hours during the hearing to: present its case in chief (90 minutes), cross-examine witnesses (45 minutes), and present its rebuttal (75 minutes).

## II. DISCUSSION OF PROPOSED REVISIONS AND BRIEFING OF LEGAL AND FACTUAL ISSUES BEFORE THE COMMISSION

### A. Proposed Requirements for Regional Haze Limits – Reasonable Progress

The Division requests that the Air Quality Control Commission consider adopting new requirements within Regulation Number 23 and the Round 2 Regional Haze SIP.

The new Regulation Number 23 requirements will further reduce emissions of visibility impairing pollutants from stationary sources to improve visibility in Colorado's twelve class I areas and assure achievement of Regional Haze RP goals.

For the second implementation period, phase 2 hearing, the Division evaluated units at 17 facilities:

- Colorado Springs Utilities ("Utilities") Nixon Power Plant Coal Handling;
- Utilities Front Range Power Plant ("FRPP") Turbines 1 and 2;
- Utilities Clear Spring Ranch Sludge Handling and Disposal Facility, 4 digester gas-fired boilers and 2 flares;
- PSCo Comanche Station Unit 3;
- PSCo Hayden Station Units 1 and 2, coal ash and sorbent handling and disposal, and fugitive dust from unpaved roads;
- PSCo Cherokee Station Turbines 5 and 6;
- PSCo Pawnee Station Unit 1 and the cooling tower;
- Manchief Generating Station Turbines 1 and 2, co-located with PSCo Pawnee Station;
- CEMEX Lyons Portland cement manufacturing facility in Lyons, CO plant Kiln, Quarries, and Raw Materials Grinding;
- Holcim Florence Portland cement manufacturing facility in Florence, CO plant Kiln, Quarry, and Finish Mills;
- GCC Pueblo Portland cement manufacturing facility plant Kiln and Clinker Cooler;
- MillerMolson Coors Boiler Support Facility Boilers 1, 2, 4, & 5;
- Evraz Rocky Mountain Steel Mill Electric Arc Furnace ("EAF"), Ladle Metallurgy Station ("LMS"), Ladle Preheaters, Round Caster, Rotary Furnace, Quench Furnace, Tempering Furnace, Rod/Bar Mill Furnace, Rail Mill Furnace, Vacuum Tank Degasser ("VTD") Boiler, Haul Roads;
- Rocky Mountain Bottle Company Furnaces B+ and C;
- Suncor Energy Denver Refinery Plant 1 and 2 Fluid Catalytic Cracking Units ("FCCU"), Plant 1 and 2 Sulfur Recovery Complexes (SRCs), Plant 1 Main Plant Flare, Process Heaters H-11, H-17, H-27, H-28/29/30, H-37, H-101, H-401/402, and H-2101, and Boilers 4 and 505;
- Denver International Airport ("DIA") Boilers, Cooling Tower, Emergency

Generators, and Miscellaneous Engines; and
- Craig Cooling Towers 1, 2, and 3.

As part of this process, the Division reviewed and conducted analyses of the projected costs of RP controls, as well as additional information regarding the four factors for RP, which includes documentation provided by the sources and other stakeholders. Through a combination of emission limit tightening, work practice and control requirements, the Division projects total emission reductions of up to 3,986 TPY for visibility impairing pollutants (NOx, SO2, PM) from additional control strategies and proposed EGU retirements and repowering in phase 2 that are currently being considered by the PUC. The Division also anticipates GHG co-benefits from the EGU retirements and repowering.

Highlighted issues and proposed revisions are described briefly below.

## 1. Proposed EGU Closure Dates

A potential issue was raised during the request for party status with how the Division has applied proposed closure dates for electric generating units in the 4-factor analyses and how proposed retirement dates and fuel conversion dates have been included in the proposed regulation, which are subject to PUC approval.[12] This has been raised by the party that includes Sierra Club, who the Division notes is already an intervening party in the proceeding currently in progress before the PUC. The Division will continue to work with the parties to this rulemaking in an attempt to resolve this concern.

## 2. Cost Considerations in 4-factor Analyses

The Division anticipates that cost considerations and cost effectiveness of control strategies will be issues to be discussed among parties leading up to and during the rulemaking hearing.

The Division is using $10,000 per ton of regional haze pollutant as the nominal cost threshold to determine cost effective control strategies for Round 2 RP. This threshold is applied to the individual pollutants in the control strategy analyses, specifically NOx, PM, and SO2. This threshold value is an increase from Round 1 and reflects the fact that with each successive round of planning, less costly and easier to implement strategies have already been adopted. Colorado has maintained this threshold throughout the planning process despite the fact that each of the Class I areas in Colorado is below the URP for 2028. We believe that this is consistent with the discussion in the July 8, 2021 EPA Regional Haze clarification memo.[13]

The Division also expects questions and additional discussion with parties regarding interest rates and cost estimates used in the 4-factor analyses. The Division hopes to

[12] NPCA-Sierra's Petition for Party Status, at 3-5.
[13] See APCD_PHS_EX-012 (Memorandum from Peter Tsirigotis, Director, EPA, to Regional Air Division Directors, Regions 1-10 (July 8, 2021)).

resolve many of these questions through ongoing collaborative conversations and review of any additional technical information that may be supplied by the parties.

### 3. Fuel Conversions Occurring Between Round 1 and Round 2

The Division is including additional revisions to Regulation 23 and the associated SBAP language with this PHS Proposal to identify and clarify fuel conversions that occurred after Round 1, but were not required by the Round 1 planning process. Specifically, the boilers at the Miller MolsonCoors Boiler Support Facility, formerly CENC, were converted from coal to gas-fired operation. Round 1 evaluated control strategies for the boilers while operating on coal and the Round 2 Technical Support Document ("TSD") evaluated potential control strategies after the units were converted to gas-fired operation. Fuel conversion dates, and the Boiler 3 retirement date, have been included in the rule as well as clarification of monitoring and recordkeeping requirements associated with gas-fired operation.

### 4. Alternate Proposals for Additional Control Strategies

Based on the information supplied when party status was requested, the Division is anticipating alternate proposals that may impact up to three (3) facilities included in the scope of this rulemaking hearing. Specifically, Suncor, GCC Pueblo, and Holcim Florence have been identified as facilities where a possible alternate proposal is being explored by Sierra Club and National Parks Conservation Association.[14] Because the proposal(s) have not yet been submitted, the Division cannot take a position at this time regarding the merits of the potential proposal(s). Upon submission of any alternate proposal in this hearing, the Division will review the proposal, and the supporting information on which it was developed, for completeness with respect to technical information, feasibility and cost analysis, and any emissions reduction strategies and regulatory requirements that may be proposed.

### 5. Uniform Rate of Progress ("URP")

As stated in EPA's 2017 Regional Haze Rule, "[t]he rate of progress in some Class I areas may be meeting or exceeding the [URP] that would lead to natural visibility conditions by 2064, but this does not excuse [Colorado] from conducting the required analysis and determining whether additional progress would be reasonable based on the four factors."[15] This was further clarified in the memorandum issued by EPA on July 8, 2021.[16] Colorado has performed a detailed analysis for each of the facilities identified for Round 2 RP review even after the modeling results indicated that all of Colorado's

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[14] NPCA-Sierra's Petition for Party Status, at 5.

[15] Protection of Visibility: Amendments to Requirements for State Plans, 40 Fed. Reg. 3,078, 3080 (Jan 10, 2017).

[16] See APCD_PHS_EX-012 (Memorandum from Peter Tsirigotis, Director, EPA, to Regional Air Division Directors, Regions 1-10 (July 8, 2021)).

class 1 areas are below the URP for 2028. The rule and SIP proposal use the detailed analysis performed for each facility as the basis for the development of the requirements and do not rely on the URP for determining cost effective RP control strategies.

### 6. EPA Startup, Shutdown, and Malfunction Memorandum

On September 30, 2021, EPA issued a new memorandum that withdrew a previous 2020 memorandum by the prior administration.[17] The September 30th memorandum references 2015 requirements associated with the use of Startup, Shutdown, and Malfunction ("SSM") provisions in SIPs. The Division is currently reviewing the memorandum and the newly reinstated 2015 requirements as they pertain to this rulemaking and SIP approval, specifically analyzing the use of EPA-approved consent decree requirements within the SIP. The Division acknowledges that several consent decrees, which are issued and enforced by the EPA, are the source of emissions limits and SSM conditions incorporated into this proposed revision to Regulation 23. Additional revisions to Regulation 23 and the SIP may be necessary as a result of this review and forthcoming discussions with EPA.

### 7. Consistency

The Division updated the SIP, proposed language in Regulation 23, and the SBAP for consistency and clarity. In particular, through preliminary conversations with EPA Region 8 staff, the Division determined it had incorrectly highlighted portions of section 7.3 in the SIP. Highlighted portions were meant to denote sources that had been acted on by the Commission in the phase 1 hearing in November 2020, but all of this section was inadvertently highlighted. This has been corrected in the revised SIP document. The Division will continue to make revisions to the appropriate documents to ensure consistency as issues are resolved during the rulemaking process.

## III. LIST OF ISSUES TO BE RESOLVED BY THE COMMISSION

1. Whether the proposed rules are consistent with the provisions of the Clean Air Act and implementing regulations regarding regional haze and SIP revisions, 42 U.S.C §§ 7410 and 7491 and 40 C.F.R § 51.300, *et seq*.
2. Whether the proposed rules and revisions are consistent with the legislative purpose of the Air Pollution Prevention and Control Act, as stated in § 25-7-102, C.R.S.
3. Whether the proposed rules and revisions comply with the requirements of

[17] APCD_PHS_EX-013 (Memorandum from Janet McCabe, Deputy Administrator, EPA, to Regional Administrators (Sept. 30, 2021)).

the State Administrative Procedure Act, §§ 24-4-101, C.R.S. et seq., the Commission's Procedural Rules, and other applicable law.

4. Whether the proposed rules and revisions comply with the requirements of the Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S. *et seq.*, including the new requirements added by Senate Bill 19-181.
5. Whether the proposed rules and revisions are consistent with the scope of the Notice of Rulemaking Hearing issued by the Commission on August 26, 2021.
6. Whether there is justification for the adoption of the proposed rules and revisions in accordance with §§ 25-7-110.5 and -110.8, C.R.S.
7. Whether the proposed revisions are cost-effective and technically feasible.
8. Whether the submitted alternative proposals comply with applicable state and federal law, and whether any portions thereof should be adopted.
9. Whether the proposed revisions comply with all other relevant requirements of state and federal law.

## IV. <u>EXHIBIT LIST</u>

The Exhibits submitted by the Division are listed on the enclosed APCD PHS Exhibit List. The Final Economic Impact Analysis includes cost updates for Rocky Mountain Bottle Company and Miller MolsonCoors Boiler Support Facility and have been incorporated into the revised TSDs. A Cost Benefit Analysis has been requested for this rulemaking. It has not been completed at this time and will be submitted at least 10 days prior to the hearing date.

The Division may also utilize exhibits identified by other parties.

## V. <u>WITNESS LIST</u>

The following potential witnesses are employees of the Colorado Department of Public Health and Environment, Air Pollution Control Division and should be contacted only through undersigned counsel.

1. Joshua Korth – Technical Support and SIP Unit Supervisor. Mr. Korth may testify regarding the development, meaning, and implementation of the proposed revisions and documents on which they are based. Mr. Korth may provide information about how the PUC process relates to this rule proposal. Mr. Korth may also testify regarding any alternative proposals submitted by other parties.

2. Sara Heald – Technical Planner. Ms. Heald may testify regarding the development, meaning, and implementation of the proposed revisions and documents on which they are based. Ms. Heald may also testify regarding any alternative proposals submitted by other parties.

3. Weston Carloss – Technical Planner. Mr. Carloss may testify regarding the development, meaning, and implementation of the proposed revisions and documents on which they are based. Mr. Carloss may also testify regarding any alternative proposals submitted by other parties.

4. Richard Coffin - Planner. Mr. Coffin may testify regarding stakeholder outreach and agency coordination related to the proposed revisions.

5. Dena Wojtach - Manager, Planning & Policy Program. Ms. Wojtach may testify regarding the development, meaning, and implementation of the proposed revisions and documents on which they are based. Ms. Wojtach may also testify regarding any alternative proposals submitted by other parties.

6. Garry Kaufman – Director. Mr. Kaufman may testify regarding the development, meaning, and implementation of the proposed revisions, as well as the Economic Impact Analysis and documents on which they are based. Mr. Kaufman may also testify regarding any alternative proposals submitted by other parties.

7. Blue Parish - Title V Operating Permits Unit Supervisor. Ms. Parish may testify regarding the netting, offset, and permitting-related issues for the proposed revisions.

The Division may also call the following potential witnesses:

8. Parties to this rulemaking, their representatives, or witnesses identified by those Parties.

## VI. IDENTIFICATION OF WRITTEN TESTIMONY

The Division does not, at this time, intend to submit any written testimony.

Respectfully submitted this 7th day of October, 2021.

By: */s/ Josh Korth*
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## CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing Prehearing Statement of the Colorado Department of Public Health and Environment, Air Pollution Control Division was served on the Parties listed below on October 7, 2021.

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*/s/ John Watson*
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