APPENDIX D

Florida Department of Environmental Protection
Division of Air Resource Management

Supplemental Regional Haze SIP – Public Comments

March 8, 2024

Preston McLane
Program Administrator
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Electronic Filing via Email to Preston.McLane@FloridaDEP.gov

Re: Comments on Florida's Supplemental Amendment to Previously Proposed Regional Haze Plan for the Second Implementation Period.

The National Parks Conservation Association (NPCA), Sierra Club, and the Coalition to Protect America's National Parks (collectively, the Conservation Organizations) submit the following comments on the Florida Department of Environmental Protection's (Florida DEP) Supplemental Amendment (SIP Supplement)[1] to its previously submitted Regional Haze Plan for the Second Implementation Period (2021 SIP Revision).[2]

The Conservation Organizations are active nationwide in advocating for strong air quality requirements to protect our national parks and wilderness areas. These groups have long participated in Regional Haze SIP comment periods, rulemakings, and litigation across the country to ensure that states and the Environmental Protection Agency (EPA) satisfy their obligations under the Clean Air Act (Act and CAA) and the Regional Haze Rule (RHR). The Conservations Organizations' members who live in Florida—including NPCA's 102,597 members, Sierra Club's 33,250 members and the Coalition's 69 current members and others who

[1] Florida DEP divided its SIP Supplement into two main documents. Citations to the document titled "Supplement to Florida Regional Haze Plan" are hereafter referred to as "SIP Supplement Package." Citations to the document titled "Supplement to Florida Regional Haze Plan for the Second Implementation Period for Florida Class I Areas" are hereafter referred to as "SIP Supplement Explainer." These two documents, along with the appendices, are collectively referred to as the "SIP Supplement."
[2] Florida DEP divided the 2021 SIP Revision into two main documents. Citations to the document titled "Submittal Number 2021-01 Regional Haze Plan" are hereafter referred to as "2021 SIP Revision Package." Citations to the document titled "Florida Regional Haze Plan for Second Implementation Period for Florida Class I Areas" are hereafter referred to as "2021 SIP Revision Explainer." These two documents, along with the appendices, are collectively referred to as the "2021 SIP Revision."

have lived and/or worked in Florida throughout their careers with the National Park Service—use and enjoy regional Class I areas that are impacted by Florida's sources of haze-forming pollution.

As detailed below, FL DEP's proposed SIP Supplement will not result in reasonable progress towards improving visibility at the Class I Areas its sources impact. These Class I Areas include Everglades National Park, which is "the largest subtropical wilderness in the United States. Everglades National Park protects an unparalleled landscape that provides important habitat for numerous rare and endangered species like the manatee, American crocodile, and the elusive Florida panther."[3]

Florida DEP fails to address nearly all the issues raised in the Conservation Organizations' comments on the 2021 SIP Revision or the expert report from Joe Kordzi, submitted in July 2021.[4] Rather than correcting the errors the Conservation Organizations previously identified, Florida DEP adds to the deficiencies with its SIP Supplement. The agency commits the following errors in the SIP Supplement:

- Florida DEP again only considers controls to reduce sulfur dioxide (SO_2) emissions. However, as discussed below and in the Conservation Organization's comments on the 2021 SIP Revision and in the 2021 Kordzi Report, there are likely available, feasible, and cost-effective controls to reduce emissions of nitrogen oxides (NOx) from Florida sources.
- Despite the Clean Air Act's and RHR's clear requirements, Florida DEP fails to provide adequate documentation to support assumptions, control costs, and claimed emissions information in its source-specific analyses.
- Although Florida DEP updates and revises its determinations that Mosaic South Pierce, Nutrien White Springs, and JEA Northside Units 1 and 2 are "effectively controlled" for SO_2, the agency does not adequately demonstrate that there are no additional controls that could reduce haze-forming emissions from these sources.
- Florida DEP determines that only a limited set of additional controls are necessary to make reasonable progress for just one source – the Georgia-Pacific Foley Mill. However, the agency again fails to correct errors in its source-specific Four-Factor Analyses, including for WestRock Fernandina Beach, Georgia-Pacific Foley Mill, and WestRock Panama City. Additionally, the agency fails to establish a cost-effectiveness threshold for assessing controls and rejects controls as not cost effective that are well below cost thresholds adopted by other states for the second planning period. Thus, Florida DEP

[3] *See infra* n.4 Conservation Orgs' 2021 SIP Revision Comments at 2 (referencing NPS Formal Consultation Call with Florida DEP for Regional Haze SIP Development, Florida Regional Haze Consultation Presentation, at 9 (May 17, 2021). "Everglades NP is an international treasure as well - a World Heritage Site, International Biosphere Reserve, a Wetland of International Importance, and a specially protected area under the Cartagena Treaty." *Id.* at 10.)

[4] *See* 2021 SIP Revision, App'x I-2, Nat'l Parks Conservation Ass'n, et al., Conservation Organizations' Comments on Florida's Proposed Revisions Regional Haze State Implementation Plan for the Second Implementation Period (July 9, 2021) [hereinafter "Conservation Orgs' 2021 SIP Revision Comments"]; 2021 SIP Revision, App'x I-2, Kordzi, Joe, A Review of the Florida Regional Haze Statement Implementation Plan (July 2021) [hereinafter "2021 Kordzi Report"].

wrongfully rejects additional available, feasible, and cost-effective controls that are necessary to make reasonable progress toward the Regional Haze Program's visibility goal.

- Florida DEP proposes to incorporate provisions from State-issued permits for covered facilities into its Regional Haze SIP. However, the proposed provisions are not practically enforceable and fail to meet the requirements of the CAA and its implementing regulations.
- Florida DEP failed to engage in meaningful consultation with Federal Land Managers (FLMs) on its SIP Supplement.
- And, once again, the agency entirely ignores the environmental justice impacts of haze-forming emissions from Florida sources.

The Conservation Organizations also submit a report prepared by Joe Kordzi (Kordzi SIP Supplement Report), which is attached and incorporated by reference into these comments.[5]

[5] Kordzi, Joe, A Review of the Florida Regional Haze State Implementation Plan Supplement of January 2024 (Feb. 2024) [hereinafter "Kordzi SIP Supplement Report"] (attached as Ex. 1). Mr. Kordzi is an independent air quality consultant and engineer with extensive experience in the regional haze program.

Table of Contents

I. Florida DEP Does Not Consider an Adequate Range of Haze-Forming Pollutants.

As it did in the 2021 SIP Revision, Florida DEP only required sources to consider potential emission controls to reduce SO_2 pollution in the SIP Supplement.[6] Yet, in its 2021 Clarification Memo, EPA clearly directs states to consider at least SO_2 and NOx both when selecting sources for Four-Factor Analyses and determining controls needed to make reasonable progress in the second planning period.[7] Indeed, in nearly all Class I areas, the largest portion of anthropogenic visibility impairment from particulate matter (PM) is attributed to sulfate and nitrate, which is caused primarily by emissions of PM precursors SO_2 and NOx, respectively.[8] Consequently, "[a] state that chooses not to consider at least these two pollutants in the second planning period should show why such consideration would be unreasonable."[9]

In the 2021 SIP Revision, Florida DEP based its decision to focus on SO_2 controls on VISTAS modeling, which it claimed shows that sulfate (a.k.a., SO_2) is the main driver of visibility impairment at most VISTAS Class I areas.[10] However, as noted in the Conservation Organizations' comments on the 2021 SIP Revision, the VISTAS modeling is severely flawed.[11] Among its many errors, the VISTAS modeling used outdated monitoring data for NOx, which caused that modeling to underreport the impact of NOx pollution on visibility impairment in Class I areas.[12] Florida DEP does not provide any additional explanation in the SIP Supplement to support its decision to focus solely on SO_2. Florida DEP, thus, continues to wrongfully ignore readily available and likely cost-effective controls to reduce NOx pollution from Florida sources, as discussed in more detail below and in the Conservation Organizations' comments on the 2021 SIP Revision.[13]

II. Florida DEP Does Not Provide Adequate Documentation to Support its Source-Specific Analyses.

The RHR makes clear that the State has a duty to conduct a robust analysis of potential reasonable progress controls, and 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

---

[6] SIP Supplement Explainer at 5.

[7] Memorandum from Peter Tsirigotis, Dir., Env't Prot. Agency, to Reg'l Air Dirs., Regions 1-10 at 4 (July 8, 2021), https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf [hereinafter "2021 Clarification Memo"] (citing Memorandum from Peter Tsirigotis, Dir., Env't Prot. Agency, to Reg'l Air Dirs., Regions 1-10 at 12 (Aug. 20, 2019), https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf [hereinafter "2019 Guidance"]).

[8] *Id.*

[9] *Id.* at 4-5.

[10] 2021 SIP Revision Explainer at 186-95.

[11] Conservation Orgs' 2021 SIP Revision Comments at 10-11.

[12] *Id.* at 11.

[13] *See infra* Sections III, IV.B-D.; *see, e.g.*, Conservation Orgs' 2021 SIP Revision Comments at 13-16, 31 (discussing potentially available and cost effective controls to reduce NOx pollution from multiple sources).

each mandatory Class I Federal area it affects."[14] If a source prepares a flawed, incomplete, or undocumented Four-Factor Analysis, the State must either require the source to make the necessary corrections or make the corrections itself to ensure that the Four-Factor Analyses are fully supported before the start of the public notice and comment period on a proposed SIP. The lack of basic documentation not only precludes the State and any independent reviewer from verifying control analyses, but it is contrary to the Act and the RHR.[15]

As discussed throughout the Kordzi SIP Supplement Report, and in more detail below, the SIP Supplement lacks sufficient documentation to support claims related to cost of controls, technical feasibility, and control performance, among other things.[16] For example, in its discussion of the Four-Factor Analysis for WestRock Panama City, Florida DEP claims that it adjusted some of the cost information from the facility-submitted analysis but concluded that none of the controls considered were cost effective.[17] However, Florida DEP did not include any explanation or documentation of the adjustments made to the WestRock Panama City analysis. Additionally, the Four-Factor Analysis for the WestRock Fernandina Beach No. 7 Boiler does not include documentation to support claimed costs for the total capital investment for new Ultra Low Sulfur Diesel (ULSD) burners.[18] Florida DEP must correct these errors and either require that the facilities provide the missing information to adequately document their control analyses, or Florida DEP must correct those errors and provide adequate documentation itself.[19]

III. Florida DEP's "Effectively Controlled" Demonstrations Fail to Satisfy the Clean Air Act and the RHR.

EPA has repeatedly explained that states cannot categorically exclude sources from a Four-Factor Analysis as "effectively controlled" where the sources have recently installed controls. In its 2019 Regional Haze Guidance, EPA explains that, even if sources have recently installed controls, states must provide a source-specific explanation as to why their decisions to exclude the sources from a Four-Factor Analysis are reasonable.[20] EPA re-emphasized this longstanding requirement in its 2021 Clarification Memo, noting that, if a state declines to select a source for further analysis based on the fact that it is already "effectively controlled" under the Regional Haze or other Clean Air Act programs, the state must "demonstrate why, for that source

[14] 40 C.F.R. § 51.308(f)(2)(iii).

[15] *Id.*; 2019 Guidance at 32 (explaining that "every source-specific cost estimate used to support an analysis of control measures must be documented in the SIP").

[16] Kordzi SIP Supplement Report at 2-3; *see infra* Sections III, IV.B-D.

[17] SIP Supplement Explainer at 44-45; Kordzi SIP Supplement Report at 13.

[18] Kordzi SIP Supplement Report at 7-8.

[19] The State (rather than regulated facilities) is tasked with complying with the requirements of the Regional Haze Program. *See* 40 C.F.R. § 51.308(f)(2)(i) ("*The State* must evaluate and determine the emission reduction measures that are necessary to make reasonable progress . . . . *The State* should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. *The 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 . . . .") (emphasis added)).

[20] 2019 Guidance at 22-23.

specifically, a [F]our-[F]actor [A]nalysis would not result in new controls and would, therefore, be a futile exercise."[21]

Despite these directives, Florida DEP improperly excludes sources from a Four-Factor Analysis, accepting "effectively controlled" demonstrations for emitting units at Mosaic South Pierce, Nutrien White Springs, and JEA Northside. Each of these demonstrations are highly flawed and fail to adequately demonstrate that the emitting units of concern at these facilities are, in fact, effectively controlled.

A. Mosaic South Pierce

Rather than conduct a Four-Factor Analysis for Sulfuric Acid Plants 10 and 11, Mosaic South Pierce submitted an "effectively controlled" demonstration, claiming that current controls at the Plants represent the best available control technology (BACT) for those sources.[22] Florida DEP agreed with Mosaic's conclusion.[23]

Mosaic South Pierce based its effectively controlled demonstration on a review of EPA's RACT/BACT/LAER clearinghouse (RBLC).[24] However, the RBLC does not represent a complete survey of all potential controls that could be installed on a source.[25] It is not reasonable for either Mosaic or Florida DEP to base a control review on this database alone. Moreover, Mosaic did not provide a complete review of possible RBLC-listed controls for its Plants. As the National Park Service (NPS) explained in its FLM consultation comments on the SIP Supplement, the RBLC shows there are likely additional controls that could that reduce SO_2 emissions from the Plants that Mosaic did not include in its demonstration—namely post-process scrubbers.[26] But as noted later in these comments, Florida DEP did not meaningfully respond to FLM comments and incorporate their recommendations.

Despite this readily available information showing that Mosaic's demonstration was not complete, Florida DEP summarily concludes that the use of post-process scrubbers "was not considered to be cost effective" for the Sulfuric Acid Plants.[27] Florida DEP does not provide any reasoning or documentation to support its conclusory statement. As a result, neither Mosaic's demonstration, nor Florida DEP's review of that demonstration meet the requirements of the Clean Air Act or RHR.[28] Florida DEP must require Mosaic to complete the Four-Factor Analyses for Sulfuric Acid Plants 10 and 11, including a review of post-process scrubbers, or conduct that review itself.

---

[21] 2021 Clarification Memo at 5.
[22] SIP Supplement Explainer at 5-6.
[23] *Id.* at 6.
[24] *Id.* at 5-6
[25] Kordzi SIP Supplement Report at 4; *see also* 2021 Kordzi Report at 14.
[26] SIP Supplement Package at 49-50; Kordzi SIP Supplement Report at 5.
[27] SIP Supplement Package at 51.
[28] 2019 Guidance at 22-23; 2021 Clarification Memo at 5.

B. Nutrien White Springs

Florida DEP relies on existing SO_2 limits for Nutrien White Springs' Sulfuric Acid Plants E and F, determining that these limits represent reasonable progress for the Plants in the second planning period.[29] Yet, similar Sulfuric Acid Plants have been demonstrated to achieve lower SO_2 emission rates than those currently required for Nutrien White Springs. As a result, Florida DEP fails to demonstrate that the plants are, in fact, effectively controlled.

First, the Conservation Organizations established in their comments on the 2021 SIP Revision that the existing 2.6 lb/ton 3hr rolling average and 2.3 lb/ton 365-day rolling average limits for Plants E and F do not demonstrate that these sources are effectively controlled.[30] As explained in those comments, the consent decree that established these SO_2 limits showed that similar plants are able to achieve lower emission rates.[31] The Conservation Organizations also noted that BACT determinations are no substitute for robust Four-Factor Analyses.[32] Florida DEP does not provide any additional information in its SIP Supplement either responding to these points or otherwise demonstrating that these SO_2 limits "effectively control" emissions from the Plants.

Second, it is unclear what effect, if any, the incorporation of the 840 lb/hr SO_2 emission cap for Plants E and F, in addition to the existing SO_2 limits discussed above, may have on SO_2 emissions from these sources. Without documenting or providing additional information on how much sulfuric acid Plants E and F produce, it is impossible to determine what effect the 840 lb/hr cap may have on emissions from the Plants – namely, whether the cap may require Nutrien White Springs to reduce SO_2 emissions from the Plants below levels required to meet the other existing SO_2 limits discussed above.[33] As a result, Florida DEP cannot rely on the 840 lb/hr SO_2 emission cap for Plants E and F to show that the facility is "effectively controlled."

Florida DEP must require Nutrien White Springs complete Four-Factor Analyses for Sulfuric Acid Plants E and F or must conduct that review itself.

C. JEA Northside Units 1 and 2

In an attempt to correct errors identified in the 2021 SIP Revision, Florida DEP supplements the "effectively controlled" demonstration for JEA Northside Units 1 and 1 by incorporating Mercury and Air Toxics Standards (MATS) emission limits for SO_2 of 0.20 lb/MMBtu, in addition to the other existing 0.15 lb/MMBtu SO_2 limits, for these units.[34]

However, Florida DEP cannot exempt a source from a complete Four-Factor Analysis by relying on controls implemented under other Clean Air Act Programs.[35] Merely supplementing

---

[29] SIP Supplement Explainer at 6-7.
[30] Conservation Orgs' 2021 SIP Revision Comments at 16-18; 2021 Kordzi Report at 12; Kordzi SIP Supplement Report at 6.
[31] Conservation Orgs' 2021 SIP Revision Comments at 17-18; 2021 Kordzi Report at 12.
[32] Conservation Orgs' 2021 SIP Revision Comments at 17; 2021 Kordzi Report at 12.
[33] *See* Kordzi SIP Supplement Report at 6.
[34] SIP Supplement Explainer at 7-8.
[35] 2019 Guidance at 22-23; 2021 Clarification Memo at 5.

the demonstration for JEA Northside Units 1 and 2 to include the MATS limit does not address the issues raised with that demonstration in the Conservation Organizations' comments on the 2021 SIP Revision.[36] As explained in the 2021 Kordzi Report, the fact that JEA Northside and other similar sources have achieved lower SO_2 emission rates shows that application of the higher 0.20 lb/MMBtu MATS limit does not demonstrate that these units are effectively controlled.[37] Additionally, neither JEA Northside nor Florida DEP provide adequate documentation to assess the existing scrubber's SO_2 removal efficiency.[38] Florida DEP also still has not required JEA Northside to analyze potential NOx controls for Units 1 and 2.[39]

Florida DEP fails to demonstrate that JEA Northside Units 1 and 2 are "effectively controlled," such that they can be reasonably exempted from the Four-Factor Analyses. The agency must require that JEA Northside conduct a full Four-Factor Analysis for both SO_2 and NOx for Units 1 and 2 or conduct that analysis itself.

IV. Florida DEP's Supplemental Four-Factor Analyses Do Not Satisfy the Clean Air Act or the RHR.

EPA expects states to "undertake rigorous reasonable progress analyses" based on the four statutory factors: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any potentially affected sources.[40] "If four-factor analyses evaluate a reasonable range of potential control options, [EPA] anticipate[s] that in many cases states will find that new (*i.e.*, additional) measures are necessary to make reasonable progress."[41] Indeed, if a measure is found to be available, feasible, and cost-effective, it satisfies the four factors and is, by definition, necessary to make reasonable progress in the second planning period.[42]

Here, however, Florida DEP rejected nearly all additional controls considered in the supplemental Four-Factor Analyses. Instead, the agency proposed that only a limited set of additional measures are necessary: (1) imposing low-sulfur fuel restrictions for Georgia-Pacific Foley Mill Power Boiler No. 1 and Bark Boiler No. 1; and (2) running the existing wet venturi scrubber with added caustic and scalant for Georgia-Pacific Foley Mill Bark Boiler No. 1.[43] Florida DEP improperly rejects numerous available, feasible, and cost-effective controls, relying on highly flawed Four-Factor Analyses for WestRock Fernandina Beach, Georgia-Pacific Foley

---

[36] Conservation Orgs' 2021 SIP Revision Comments at 21; 2021 Kordzi Report at 17-18; Kordzi SIP Supplement Report at 6.
[37] 2021 Kordzi Report at 17-18.
[38] *Id.*
[39] *See generally*, SIP Supplement Explainer at 7-8; 2021 Kordzi Report at 18-19; Kordzi SIP Supplement Report at 6.
[40] 2021 Clarification Memo at 2; 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i).
[41] 2021 Clarification Memo at 8.
[42] 82 Fed. Reg. 3078, 3093 (Jan. 10, 2017); 2021 Clarification Memo at 8 ("[W]hen the outcome of a four-factor analysis is a new measure, that measure is needed to remedy existing visibility impairment and is necessary to make reasonable progress.").
[43] *See generally*, SIP Supplement Explainer at 10-49.

Mill, and WestRock Panama City. As a result, its review of these analyses fails to satisfy the requirements of Clean Air Act and RHR.

A. Florida DEP Did Not Set a Cost-Effectiveness Threshold and Improperly Rejects Available and Cost-Effective Controls.

In its 2021 SIP Revision, Florida DEP did not set a cost-effectiveness threshold for evaluating control costs in Four-Factor Analyses. The agency still fails to establish a threshold in its SIP Supplement. Instead, it rejects additional controls for all but one facility as not cost effective without any explanation.[44] For example, Florida DEP rejects as not cost effective (1) switching the WestRock Fernandina Beach Power Boiler No. 7 from coal to gas at $7,374/ton of SO_2 reduced, and (2) increasing caustic to the exiting wet scrubber at WestRock Panama City Combination Boiler No. 4 at $6,816/ton SO_2 reduced.[45] The agency similarly rejects installation of wet scrubbers on the Georgia-Pacific Foley Mill Recovery Furnaces 2, 3, and 4 at a range of $5,197 to $7,779/ton of SO_2 reduced.[46]

Florida DEP has not provided a reasoned basis for rejecting the adoption of additional regional haze controls for the second planning period because it has not defined or justified a cost-effectiveness threshold. Although the Clean Air Act does not require Florida DEP to "use of a bright line rule" for determining cost effectiveness, the Ninth Circuit has explained that "the law does require [the agency] to cogently explain why it has exercised its discretion in a given manner."[47] To provide a reasoned basis for its decisions, Florida DEP must first establish a threshold, or explain and justify some other objective measure, for determining cost effectiveness that is in line with other states.

To that end, Florida DEP should set at $10,000/ton of pollutant reduced cost-effectiveness threshold, similar to that employed by other states. Both Colorado and Nevada used a $10,000/ton of pollutant reduced threshold.[48] In setting its threshold, Colorado explained that

[44] Florida DEP agreed with Georgia-Pacific Foley Mill's conclusion that it is cost effective to run Bark Boiler No. 1's existing wet venturi scrubber with added caustic and scalant at a cost of $2,627/ton of SO_2 reduced. SIP Supplement Explainer at 26-28.
[45] *Id.* at 13, 44-45.
[46] *Id.* at 39; *see also* Kordzi SIP Supplement Report at 3-4.
[47] *Nat'l Parks Conservation Ass'n v. E.P.A.*, 788 F.3d 1134, 1142-43 (9th Cir. 2015) (citation and quotation omitted).
[48] In the Matter of Proposed Revisions to Regulation Number 23, Colo. Dep't of Pub. Health & Env't, Air Pollution Control Div., Prehearing Statement at 7 (Oct. 7, 2021), https://drive.google.com/drive/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v [hereinafter "Colorado SIP Revision"] ("The Division is using $10,000 per ton of regional haze pollutant as the nominal cost threshold to determine cost effective control strategies for Round 2 RP. This threshold is applied to the individual pollutants in the control strategy analyses, specifically NOx, PM, and SO_2. This threshold value is an increase from Round 1 and reflects the fact that with each successive round of planning, less costly and easier to implement strategies have already been adopted.") (attached as Ex. 2); Nev. Div. of Env't Prot., Nevada Regional Haze State Implementation Plan for the Second Planning Period at 5-6 (Aug. 2022), https://ndep.nv.gov/uploads/air-plan_mod-docs/All_SIP_Chapters.pdf ("NDEP is relying on a cost-effectiveness ($/ton reduced) threshold of $10,000/ton when considering potential new control measures during the second implementation period. Compared to the BART threshold used during the

"[t]his 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."[49] Under this threshold, all the additional controls noted above are cost effective. Indeed, even under the $7,000 per ton threshold adopted by New Mexico,[50] many of the controls noted above would still be considered cost effective. A $10,000/ton threshold would achieve significant—and much-needed—reductions in visibility-impairing pollution from Florida sources.

B. WestRock Fernandina Beach Power Boiler No. 7

WestRock Fernandina Beach is a fully integrated Kraft linerboard mill that produces linerboard from wood pulp and pulp derived from recycled corrugated containers. The significant source of SO_2 at the WestRock Fernandina Beach Mill is Power Boiler No. 7, which fires coal and oil and/or natural gas and serves as a backup non-condensable gases (NCGs) control device.[51] For its 2021 SIP Revision, the facility's Four-Factor Analysis included consideration of "reducing coal usage to 125 tons per day [(tpd)], installing a wet scrubber after existing [electrostatic precipitator (ESP)], installing a [dry sorbent injection (DSI)] with existing ESP, or installing [spray dry absorber (SDA)] with new fabric filter."[52] Based on this analysis, Florida DEP rejected installation of a wet scrubber, DSI, and SDA as not cost effective, but concluded that reducing WestRock Fernandina Beach's coal usage to 125 tpd is cost effective and necessary for reasonable progress.[53] In the SIP Supplement, WestRock updated its Four-Factor Analysis for Power Boiler No. 7 to consider ceasing all burning at this unit.[54] However, Florida DEP rejected this control as not cost effective.[55]

The Conservation Organizations appreciate that Florida DEP was responsive to our comments on the 2021 SIP Revision and required that WestRock supplement its initial Four-Factor Analysis with consideration of whether removing all coal firing from Power Boiler No. 7 is cost effective.[56] We are similarly appreciative of Florida DEP's revisions to WestRock's cost-effectiveness analysis, applying the current bank prime interest rate and 30-year equipment lifetime (correcting the 4.75% and 20-year assumptions).[57] Unfortunately, WestRock's

---

first implementation period of $5,000/ton, the new threshold for reasonable progress controls is double. This is to ensure that the entire fleet of potential new control measures throughout Nevada are thoroughly considered, as well as, to
ensure that enough controls are implemented during the second period to continue achieving reasonable progress at Jarbidge WA and other out-of-state CIAs.") (attached as Ex. 3).

[49] Colorado SIP Revision at 7.

[50] NM Env't Dep't and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2 at 12, https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf (attached as Ex. 4).

[51] SIP Revision Explainer at 269.

[52] *Id.* at 270.

[53] *Id.* at 274.

[54] SIP Supplement Explainer at 10-15.

[55] *Id.* at 14.

[56] *Id.* at 10.

[57] *Id.* at 12.

supplemental information[58] and Florida DEP's consideration and analysis contain numerous fatal flaws.[59]

WestRock's supplemental information fails to provide the required documentation, and Florida DEP did not require WestRock to supplement its submittal with the required documentation. Nor did Florida DEP itself research or provide documentation to support the information submitted by WestRock. As explained above and in the Conservation Organizations' comments on the 2021 SIP Revision, Florida's SIP must be supported by a reasoned analysis that includes and cites to the technical support documentation it proposes to rely on and use as part of its SIP Revision.[60] For example, WestRock suggests that "there will be a total capital investment of $18,750,000 for the new ultra-low sulfur diesel (USLD) burners and required infrastructure for that backup fuel."[61] Neither WestRock nor Florida DEP provide documentation for this capital investment cost. As explained in the Kordzi SIP Supplement Report, WestRock also did not provide documentation to support its assertion that to cease burning coal it must replace its current ULSD burners with new burners.[62] Similarly, WestRock has not documented what constitutes 100% full load for Power Boiler No. 7, despite asserting that full load capacity is necessary if the facility ceases burning coal.[63]

Moreover, Florida DEP's revised analysis demonstrates that removing all coal firing at Power Boiler No. 7 is cost effective at $7,374/ton of SO_2 reduced.[64] This value is within the range of what other states have determined to be cost effective for the second planning period.[65] Indeed, WestRock's own (flawed) analysis shows this control is cost effective at a value of $7,788/ton of SO_2 reduced.[66] Yet, Florida DEP summarily dismisses both its cost estimate and WestRock's as "not cost effective" and provides no rationale for its proposed determination.[67]

To support its proposed determination that switching from coal to gas is not necessary for reasonable progress, Florida DEP suggests that "[g]iven the extent to which coal usage caps in current permits already reduce SO_2 emissions, the Department finds that eliminating coal as a fuel source is not necessary for reasonable progress."[68] Florida DEP appears to suggest that the visibility benefits from ceasing coal burning are too small, and thus, rejects this control measure for Power Boiler No. 7 even though its own analysis shows this control measure is cost effective. The State's approach is inconsistent with the Clean Air Act and RHR. While natural visibility is the goal of the Regional Haze Program, states must base their control decisions on a review of

[58] SIP Supplement, App'x B-1, WestRock Fernandina Beach Mill Supplemental Four Factor Analysis.
[59] SIP Supplement Explainer at 10-15 (Section 7.8.2.5).
[60] *See supra* Section II; Conservation Orgs' 2021 SIP Revision Comments at 10 (citing 40 C.F.R. §§ 51.100, 51.102, 51.103, 51.104, 51.105 and Appendix V to Part 51).
[61] SIP Supplement Explainer at 11.
[62] Kordzi SIP Supplement Report at 7.
[63] *Id.* at 7-8.
[64] SIP Supplement Explainer at 13, tbl.7-32b.
[65] *See supra* Section IV.A.
[66] SIP Supplement Explainer at 11.
[67] *Id.* at 13.
[68] *Id.* at 14.

the four statutory factors.[69] If based on a Four-Factor Analysis, a control measure is found to be feasible and cost effective, the measure is, by definition, necessary to make reasonable progress.[70] Thus, as EPA has made clear, states cannot use visibility to summarily dismiss cost-effective controls.[71]

Similarly, the State must first subject WestRock to a Four-Factor Analysis in accordance with § 51.308(f)(2)(i) before it can determine that there are no emission reducing options available. Contrary to these requirements, Florida DEP suggests that WestRock's consideration of and proposal to reduce coal to 125 tpd is good enough for reasonable progress. The State's proposed determination is not based on any regional haze requirement or Four-Factor Analysis.[72]

C. Georgia-Pacific Foley Mill

Georgia-Pacific Cellulose/Foley Cellulose, LLC, owns and operates a softwood Kraft pulp mill (Foley Mill) located in Perry, Florida, which manufactures bleached market, fluff, and specialty dissolving cellulose pulp.[73] Because Florida DEP explained in the 2021 SIP Revision that it was still in the process of reviewing the information that Georgia-Pacific submitted, the Conservation Organizations presented details on the myriad of issues in Georgia-Pacific's information in their comments on the 2021 SIP Revision to inform the agency's ongoing review of the facility's analysis.[74]

While we appreciate that Florida DEP requested additional information in March 2021 for one of the six emission units under evaluation at this facility – Power Boiler No. 1[75] – as discussed in the Kordzi SIP Supplement Report, neither the SIP Supplement nor Georgia-Pacific's supplemental Four-Factor Analyses[76] address many of the deficiencies identified in the 2021 Kordzi Report, including the following: (1) lack of required documentation; (2) only relying on EPA's RBLC to identify technically feasible controls and not considering other proven instances of technically feasible controls installed on similar sources; (3) failure to address particular issues with individual cost items; and (4) failure to consider upgrades to existing

[69] 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i); *State Farm Mut. Auto. Ins. Co.*, 463 U.S. at 43 (explaining that an agency rule is arbitrary and capricious "if the agency has relied on factors which Congress has not intended it to consider").
[70] 82 Fed. Reg. at 3093; 2021 Clarification Memo at 8 ("[W]hen the outcome of a four-factor analysis is a new measure, that measure is needed to remedy existing visibility impairment and is necessary to make reasonable progress.").
[71] 2021 Clarification Memo at 13.
[72] SIP Supplement at Explainer at 10-15; 2021 SIP Revision Explainer at 273-74.
[73] SIP Supplement at Explainer 15.
[74] Conservation Orgs' 2021 SIP Revision Comments at 20; *see also* 2021 Kordzi Report at 13-17.
[75] SIP Supplement at Explainer at 16.
[76] *Id*. at 17 (referencing August 30, 2022, supplemental Four-Factor Analyses (Appendix B-2b); undocumented discussions between Florida DEP and Georgia-Pacific representatives on September 20, 2022; November 16, 2022, revised Four-Factor Analysis (Appendices B-2c, B-2d)).

controls.[77] Therefore, the issues raised in our comments on the 2021 SIP Revision and in the 2021 Kordzi Report are still relevant and must be addressed.[78]

In the SIP Supplement, Florida DEP explains that "[i]n September of 2023, Georgia-Pacific announced that the Foley Mill will be shutdown . . . [and] Georgia-Pacific has stated that it will explore selling of the mill to potential investors."[79] As long as Georgia-Pacific or future owners hold Clean Air Act permits that allow for emissions from the facility, the Foley Mill is subject to the regional haze reasonable progress requirements. Specifically, for this planning period, Florida DEP's Regional Haze SIP must include the required Four-Factor Analyses, including appropriate controls that would apply should the Foley Mill restart. Alternatively, Florida DEP must revoke the Clean Air Act permits for the Foley Mill and require that the owner/operator obtain a new source review permit as a new source if the owner/operator decides to restart.

1. Florida DEP Must Evaluate Common Controls for the Foley Mill Emission Units.

Given the fact that several emitting units already share at least one common stack, as the Kordzi SIP Supplement Report explains, there is the potential to install SO_2 emission control devices on the common stack, which would potentially provide cost savings. Florida DEP's SIP Supplement explains that "[t]he exhaust flue [for Power Boiler No. 1] shares a common stack together with Power Boiler No. 2 and Bark Boilers Nos. 1 and 2."[80] SO_2 control devices could, thus, potentially be installed upstream of the common stack at the Foley Mill.[81] Yet, neither Georgia-Pacific nor Florida DEP explored common SO_2 controls for these units. Additionally, Florida DEP "must also investigate whether two or all of the three recovery furnaces can also share an SO_2 control."[82] In order for Florida DEP and the public to be able to thoroughly investigate the common stack options, the agency "must require that Foley provide diagrams, schematics and/or other documentation that illustrates the potential opportunity to install SO_2 control devices that could service two or more of the boilers and recovery furnaces."[83]

2. Florida DEP Must Correct Errors in the Four-Factor Analysis for Power Boiler No. 1 and Evaluate Whether There Are Cost-Effective Controls.

Power Boiler No. 1 was constructed at the Foley Mill 71 years ago, and Florida DEP's SIP Supplement explains that it is capable of producing 195,000 lbs/hour of steam firing a variety of fuels.[84] The fuels allowed include natural gas, No. 6 fuel oil, on-specification used oil,

[77] Kordzi SIP Supplement Report at 8.
[78] *Id.*
[79] SIP Supplement Explainer at 15.
[80] *Id*. at 18.
[81] Kordzi SIP Supplement Report at 8.
[82] *Id.*
[83] *Id.*
[84] SIP Supplement Explainer at 18.

and onsite/offsite-generated tall oil.[85] The exhaust flue shares a common stack together with Power Boiler No. 2 and Bark Boilers Nos. 1 and 2.[86]

As noted above, Florida DEP has not required Georgia-Pacific to address, and has not addressed itself, the many errors the Conservation Organizations raised with Georgia-Pacific's Four-Factor Analysis for Power Boiler No. 1 in our comments in on the 2021 SIP Revision.[87] Although Florida DEP had the opportunity to address and correct those errors in the SIP Supplement and yet it did not. For instance, Florida DEP blindly accepted Georgia-Pacific's decision to only consider two types of scrubber technologies for Power Boiler No. 1.[88] Georgia-Pacific and/or Florida DEP should have also considered wet scrubbing with packed bed and wet venturi scrubber with added caustic.[89] Notably, Georgia-Pacific already uses a wet venturi scrubber with caustic for Bark Boiler No. 1.[90] Thus, the issues raised in our previous comments are still relevant and must be corrected before Florida DEP finalizes the SIP Supplement.

Beyond the issues that the Conservation Organizations previously raised, Florida DEP commits additional errors in its review of Georgia-Pacific's revised analysis for Power Boiler No. 1. First, Florida DEP relies on a Georgia-Pacific's highly flawed and "cobbled-together cost estimate" for wet scrubbers at Power Boiler No. 1.[91] Georgia-Pacific used a 2020 cost estimate for wet scrubbers at an Oregon lime kiln and then adjusted that estimate in multiple ways, including adjustments based on a "detailed vendor quote" for a Georgia facility.[92] As the Kordzi SIP Supplement Report explains, Georgia-Pacific failed to provide adequate documentation to support its revised cost estimate and did not include any rationale for using cost information from a lime kiln, which is a much different source.[93] Indeed, neither Georgia-Pacific nor Florida DEP demonstrate that this revised cost estimate for wet scrubbers satisfies EPA's Control Cost Manual methodology, which requires that cost estimates be accurate within ± 30%.[94] Second, Florida DEP should also require Georgia-Pacific to analyze upgrades to the TRS pre-scrubber(s)

---

[85] *Id.*
[86] *Id.*
[87] Conservation Orgs' 2021 SIP Revision Comments at 20; 2021 Kordzi Report at 14-16 (discussing overarching issues with Georgia-Pacific's analysis for the Foley Mill, like lack of adequate documentation, as well as specific issues with its cost analysis for controls for Power Boiler No. 1, such as its wet scrubber and DSI cost analyses and only considering these two controls identified by Georgia-Pacific).
[88] SIP Supplement Explainer at 18-25.
[89] 2021 Kordzi Report at 15 (referencing Bionomic Industries, "Modern Gas Cleaning Techniques For TRS and SO_2 Control in the Pulp and Paper Industry," (Jan. 1, 2004), https://www.energy-xprt.com/articles/modern-gas-cleaning-techniques-for-trs-and-so2-control-in-the-pulp-and-paper-industry-6470); *see also* Kordzi SIP Supplement Report at 9 (referencing EPA, Economic and Cost Analysis for Air Pollution Regulations, Cost Reports and Guidance for Air Pollution Regulations, EPA Air Pollution Control Cost Manual, Section 5, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution).
[90] *See infra* Section IV.C.3.; Kordzi SIP Supplement Report at 9.
[91] Kordzi SIP Supplement Report at 10.
[92] SIP Supplement Explainer at 19-20.
[93] Kordzi SIP Supplement Report at 10.
[94] *Id.*

to achieve additional SO_2 emission reductions for Power Boiler No. 1.[95] As the Kordzi SIP Supplement Report explains, since Florida DEP indicates the LVHC-NCG is the main source of SO_2, it must require that Geogia-Pacific investigate upgrades to the TRS pre-scrubber(s).[96]

Additionally, Florida DEP states, without any explanation, that EPA's regional haze guidance requires that it "impose SIP emission limits that reduce the unit's potential to emit to levels that are slightly higher than the historical emission levels."[97] Florida DEP neither explains the meaning of this statement nor does it provide a citation to the EPA guidance it references.[98] Florida DEP must provide a meaningful explanation for its assertion, citing to EPA's guidance, or remove this sentence from the SIP.

Once the corrections are made and a complete and accurate Four-Factor Analysis is prepared – either by the company or the State – Florida DEP must revaluate whether the wet scrubber, DSI system, or other controls and upgrades are cost effective for Power Boiler No. 1. Given the numerous errors in Georgia-Pacific's analysis discussed above, it is unreasonable for Florida DEP to rely on the facility's cost-effectiveness values for controls considered.

3. Florida DEP Must Correct the Errors in the Four-Factor Analysis for Bark Boiler No. 1 and Evaluate Whether There Are Cost-Effective Controls.

Bark Boiler No. 1 fires a variety of fuels including wood materials (bark, chips, sawdust, etc.), natural gas, No. 6 fuel oil, facility generated on-specification used oil, and onsite/offsite-generated tall oil.[99] The exhaust flue shares a common stack together with Power Boilers Nos. 1 and 2 and Bark Boiler No. 2.[100] In its previous and revised Four-Factor Analyses for Bark Boiler No. 1, Georgia-Pacific considered just one possible control, "operational changes" to "run the existing wet venturi scrubber with added caustic at all times NCG gases are being combusted in the Bark Boiler No. 1, not just when the TRS pre-scrubber is unavailable."[101] Georgia-Pacific's initial analysis asserts that because the unit "is already equipped with a scrubber, only the addition of more caustic is evaluated."[102] The facility declined to even analyze the installation of a wet scrubber or DSI for this boiler, relying on its (highly flawed) analysis for Power Boiler No. 1.[103] Rather than require Georgia-Pacific to conduct a rigorous Four-Factor Analysis in accordance with the Clean Air Act and RHR, Florida DEP just accepts Georgia-Pacific's supplemental analysis and determines that the only controls required for Bark Boiler No. 1 are

---

[95] *Id.* at 9.
[96] *Id.*
[97] Kordzi SIP Supplement Report at 16 (referencing SIP Supplement Explainer at 23).
[98] *Id.* at 16.
[99] SIP Supplement Explainer at 26.
[100] *Id.*
[101] *Id.*
[102] SIP Supplement, App'x B, Foley Mill Four-Factor Analysis, at 3-3 (Oct. 22, 2020).
[103] SIP Supplement, App'x B, Foley Mill Four-Factor Analysis, at § 7.8.3.2 (Nov. 16, 2022); *see supra* Section IV.C.2.

(1) "adding caustic and scalant to the scrubber system [as Georgia-Pacific proposes]" and (2) imposing low-sulfur fuel restrictions."[104]

Florida DEP must consider other available SO_2 controls beyond adding caustic and scalant to the existing wet venturi scrubber for Bark Boiler No. 1. As the 2021 Kordzi Report explains, wet venturi scrubbers in this application are typically used to control particulates.[105] Thus, Florida DEP must consider other available SO_2 controls, including those that can achieve 90% or better removal.[106] Florida DEP must also require Georgia-Pacific to consider optimizing its existing TRS pre-scrubber for Bark Boiler No. 1.[107] As with Power Boiler No. 1, Florida DEP explains that LVHC-NCG is the main source of SO_2 from this boiler and that the LVHC-NCG is sent through a TRS pre-scrubber before going to this boiler.[108]

At the very least, Florida DEP must require that Georgia-Pacific investigate adding higher amounts of caustic to the wet venturi scrubber and must provide documentation to support its analysis. Florida DEP must use the same analysis for the Foley Mill as it did for the WestRock Unit 3 wet venturi scrubber where use of caustic was evaluated at upwards of 98% control.[109] Florida DEP must treat the Georgia-Pacific Foley Mill as it has other mills.[110] Florida DEP claims that adding more caustic and scalant to maintain a pH of 8 would only achieve 51% SO_2 removal based on "engineering tests."[111] Yet, neither the State nor Georgia-Pacific provided the noted engineering tests or any other documentation to support this claim. Florida DEP must also include the noted engineering tests, all associated analysis, and complete documentation for all figures and assumptions underlying its analysis.[112]

4. Florida DEP Must Correct the Errors in the Four-Factor Analyses for Recovery Furnaces Nos. 2, 3 and 4 and Include Requirements for Cost-Effective Controls.

Florida DEP must correct the errors in its analysis because its flawed analysis demonstrates additional controls are cost effective. The agency must include emission limitations for SO_2 based on additional controls for all three recovery furnaces. The three recovery furnaces all fire black liquor and range in age from 67, 60, and 51 years old, respectively.[113] In addition to firing black liquor, all three of the recovery furnaces "are authorized to fire the following fuels for startup, shutdown, and as a supplemental fuel to maintain flame stability in the furnace: No. 6 fuel oil; No. 2 distillate oil; onsite or offsite - generated tall oil; on-specification used oil that meets the applicable requirements of 40 CFR

---

[104] SIP Supplement Explainer at 28-29.

[105] 2021 Kordzi Report at 16.

[106] *Id.*

[107] Kordzi SIP Supplement Report at 9, 11.

[108] SIP Supplement Explainer at 26.

[109] Kordzi SIP Supplement Report at 11.

[110] *Nat'l Parks Conservation Ass'n v. U.S. Env't Prot. Agency*, 788 F.3d 1134, 1141, 1145 (9th Cir. 2015) (EPA [and state] regional haze SIP actions must be consistent; an internally inconsistent analysis is arbitrary and capricious) (citation omitted).

[111] SIP Supplement Explainer at 27.

[112] Kordzi SIP Supplement Report at 11.

[113] Supplemental SIP Explainer at 29.

Part 279; natural gas; ultra-low sulfur distillate oil and methanol (No. 2 Recovery Furnace only)."[114] Georgia-Pacific's Four-Factor Analyses of common flue gas desulfurization (FGD) systems for these furnaces includes SDAs, DSI, and conventional wet scrubbers, but Florida DEP rejects all of these controls based on Georgia-Pacific's assertions and flawed cost-effectiveness analyses.[115] Instead, Florida DEP proposes that only existing measures for the three recovery furnaces were necessary to make reasonable progress.[116]

Florida DEP's control analyses contain multiple errors. For instance, Florida DEP incorrectly claims that installing SDA systems upstream of the existing ESPs for the recovery furnaces is not feasible. Florida DEP asserts that, to be cost effective for the recovery furnaces, Georgia-Pacific could only inject caustic materials upstream of the existing ESPs for the furnaces to neutralize SO_2 and remove the resulting solids formed and excess caustic materials. But the agency claims that this would contaminate and adversely affect the recovery process.[117] Yet, as explained in the Kordzi SIP Supplement Report, Florida DEP appears to conflate SDA systems with DSI systems and its assertions do not comport with the typical installation of SDA systems as provided in EPA's Control Cost Manual.[118] Moreover, in addition to SDA, Florida DEP must also consider additional dry scrubbing technologies (*e.g.*, Circulating Dry Scrubber).[119]

Additionally, Florida DEP makes incorrect or unsupported assumptions in its cost analysis for wet scrubbers for the recovery furnaces. Florida DEP assumes Black Liquor Solids (BLS) values for each furnace, but it does not provide documentation to support those values, correlate those values to the uncontrolled SO_2 emissions for each of the furnaces, or explain why the BLS values in Georgia-Pacific's October 22, 2020, analysis were higher.[120] Florida DEP also uses the BLS rates for the furnaces to determine some of the operating and maintenance costs for wet scrubbers.[121] However, because SO_2 comes from the BLS, Florida DEP engages in an apples-to-oranges analysis in applying the permitted capacity to an average uncontrolled SO_2 value, which is unreasonable.[122] Florida DEP further fails to provide documentation to support other costs included in its wet scrubber analysis, including the vendor quote on which Georgia-Pacific bases its cost assumptions and Georgia-Pacific's calculations for the ratioed electrical usage values.[123] The agency escalates costs by 8% for Allowance for Funds Used During

[114] *Id.* at 29-30.
[115] *Id.* at 31-41.
[116] *Id.* at 40-41.
[117] *Id.* at 31.
[118] Kordzi SIP Supplement Report at 11-12 (referencing EPA, Economic and Cost Analysis for Air Pollution Regulations, Cost Reports and Guidance for Air Pollution Regulations, EPA Air Pollution Control Cost Manual, Section 5, SO_2 and Acid Gas Controls, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, at 1-7, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution).
[119] Kordzi SIP Supplement Report at 12.
[120] *Id.*
[121] *Id.*
[122] *Id.*
[123] *Id.*

Construction (AFUDC), which is not allowed.[124] It also assumes that wet scrubbers would achieve only 90% SO_2 removal when wet scrubbers can easily achieve 98% control.[125]

Yet, even under Florida DEP's flawed cost analyses, installation of wet scrubber systems on each of the recovery furnaces is cost effective. In fact, Florida DEP found the following cost-effectiveness values:[126]

- No. 2 Recovery Furnace - $7,779/ton of SO_2 removed;
- No. 3 Recovery Furnace - $5,197/ton of SO_2 removed;
- No. 4 Recovery Furnace - $6,587/ton of SO_2 removed.

All these values are below cost-effectiveness thresholds adopted by other states during this planning period.[127] Moreover, Florida DEP provides no basis for its assertion that the wet scrubber option is not cost effective. Therefore, Florida DEP must revise the SIP Supplement to include emission limitations for SO_2 based on additional wet scrubber controls for all three recovery furnaces.

Beyond the errors in its cost analyses for the controls considered, Florida DEP failed to consider other feasible and available controls to reduce SO_2 emissions from the recovery furnaces. As the Kordzi Reports explain, Florida DEP's Four-Factor Analyses for the furnaces should consider the EPA Region 4's January 31, 2007, letter to the North Carolina Department of Environment, concerning the best available retrofit technology (BART) analysis for the Blue Ridge Canton Paper Mill.[128] EPA's letter to North Carolina discusses process changes applicable

---

[124] Kordzi SIP Supplement Report at 12, (referencing EPA, Economic and Cost Analysis for Air Pollution Regulations, Cost Reports and Guidance for Air Pollution Regulations, EPA Air Pollution Control Cost Manual, Section 1, Introduction, Chapter 2, Cost Estimation: Concepts and Methodology, at 11 (Nov. 2017), https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution; *see also Oklahoma v. U.S. E.P.A.*, 723 F.3d 1201, 1212 (10th Cir. 2013) (holding EPA has a reasonable basis for rejecting cost estimates where the agency explained the estimates "contain[ed] ... fundamental methodological flaws, such as including escalation and Allowance for Funds Used During Construction (AFUDC)…" and that "[t]he cost of scrubbers would not be substantially higher than those reported for other similar projects if OG & E had used the costing method and basis, i.e., overnight costs in current dollars, prescribed by the Control Cost Manual…") (internal citations omitted).

[125] Kordzi SIP Supplement Report at 13, (referencing (referencing EPA, Economic and Cost Analysis for Air Pollution Regulations, Cost Reports and Guidance for Air Pollution Regulations, EPA Air Pollution Control Cost Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, at 1-3 – 1-5 (April 2021), https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[126] SIP Supplement Explainer at 39.

[127] *See supra* Section IV.A.

[128] 2021 Kordzi Report at 25; Kordzi SIP Supplement Report at 9 (referencing Letter with Enclosure from Kay T. Prince, Chief, Air Planning Branch, Region 4, U.S. Env't Prot. Agency, to Sheila Holman, Div. of Air Quality, NC Dep't of Env't and Natural Resources, EPA Comments on BART for the Blue Ridge Paper – Canton Mill (Jan. 31, 2007) (attached as Ex. 5).

to Geogia-Pacific's Foley Mill recovery furnaces that should be assessed. Florida DEP must also consider additional dry and wet scrubbing technologies, like Circulating Dry Scrubbers and packed bed scrubbers.[129]

To comply with the Clean Air Act and RHR, Florida DEP must correct the errors in its Four-Factor Analyses and include emission limitations for SO_2 based on cost-effective wet scrubber controls for all three recovery furnaces.

D. WestRock Panama City

WestRock Panama City is a Kraft pulp and paper mill in Panama City, Florida. The significant sources of SO_2 at the WestRock Panama City Mill are Combination Boilers Nos. 3 and 4 and Recovery Boilers Nos. 1 and 2.[130] In the 2021 SIP Revision, Florida DEP explained that it had not yet completed a Four-Factor Analysis for the WestRock Panama City Mill, and so, would include a complete analysis in a future SIP submittal.[131] Thus, Florida DEP did not make a reviewable determination of what constitutes reasonable progress for this facility in the 2021 SIP Revision. The Conservation Organizations' comments on the 2021 SIP Revision[132] identified issues with and deficiencies in WestRock's Four-Factor Analysis.[133]

As an initial matter, Florida DEP explains in the SIP Supplement that, although the Panama City Mill suspended operations in 2022, the facility still has a valid operating permit and "[i]t is unclear at this time whether any of these units will operate in the future."[134] Because this facility may restart operations in the future, Florida DEP must either (1) include the required Four-Factor Analyses, including appropriate controls that would apply should the Panama City Mill restart; or (2) revoke the facility's Clean Air Act permits and require that the owner/operator obtain a new source review permit as a new source if it decides to restart.

Florida DEP's SIP Supplement does not address the issues and deficiencies detailed in our comments on the 2021 SIP Revision. Instead, Florida DEP relies on the same flawed Four-Factor Analyses WestRock submitted earlier to conclude in the SIP Supplement that only WestRock's existing controls are necessary to make reasonable progress.[135] As the Kordzi SIP Supplement Report explains, the SIP Supplement does not correct the numerous deficiencies identified in the 2021 Kordzi Report, including failure to: (1) provide the required documentation; (2) exclude improper cost items; (3) consider proven SO_2 control technologies; (4) consider upgrades to existing controls; (5) address issues with specific cost items; and (6) conduct due diligence in investigating fuel switching.[136] While Florida DEP had an opportunity to resolve these SIP approvability issues with its SIP Supplement, it did not. Therefore, the

---

[129] Kordzi SIP Supplement Report at 11-12.
[130] SIP Supplement Explainer at 41.
[131] 2021 SIP Revision Package at 7, n.1.
[132] Conservation Orgs' 2021 SIP Revision Comments at 22; 2021 Kordzi Report at 22-25.
[133] 2021 SIP Revision, App'x G-2j.
[134] SIP Supplement Explainer at 42.
[135] *Id.* at 45-46, 49; SIP Supplement, App'x B-3, WestRock Panama City Four-Factor Analysis (Oct. 2020) [hereinafter "Panama City Four-Factor Analysis"].
[136] Kordzi SIP Supplement Report at 13.

issues identified in the Conservation Organizations' comments on the 2021 SIP Revision and the 2021 Kordzi Report remain relevant and must be addressed.

Adding to these errors, Florida DEP's SIP Supplement does not require that WestRock correct its errors, contains undocumented assertions, and does not include the agency's revised control cost analyses. For example, while Florida DEP explains in the SIP Supplement that parts of WestRock's analysis "were not justified adequately or were inconsistent with EPA's Cost Control Manual," Florida DEP did not make all the corrections required for the Four-Factor Analysis nor did it provide its revised cost analysis for public review and comment.[137] Furthermore, Florida DEP provides no support for its assertion that the control technology options considered for Combination Boilers Nos. 3 No. 4 "are not cost effective."[138] Florida DEP also fails to support its similar assertions regarding Recovery Boilers Nos. 1 and 2, as it again fails to provide its revised cost-effectiveness calculations in the SIP Supplement and provides no support for its assertions.[139] Finally, as explained above, the RHR requires Florida DEP to base its reasonable progress determinations on a rigorous application of the four statutory factors, and Florida DEP's weight of evidence analysis is misplaced.[140]

Even based on WestRock's highly flawed Four-Factor Analysis, there are likely cost-effective controls available to reduce SO_2 emissions from the facility's boilers. For example, WestRock's own analysis shows that it is cost effective to increase caustic to the wet scrubber for Combination Boiler No. 4 at a value of \$6,816/ton of SO_2 reduced.[141] As discussed above, this is below the threshold of \$10,000/ton set by other states.[142] Thus, it was unreasonable for Florida DEP to reject this control. Additionally, WestRock's analysis shows that replacing No. 6 fuel oil with gas for Recovery Boiler No. 2 has a cost-effectiveness value of \$12,217/ton of SO_2 reduced.[143] When the required corrections are made to the Four-Factor Analysis for this boiler, it is likely this control would be even more cost effective and likely within the range of what other states have determined to be cost effective for the second planning period.

Florida DEP must either require WestRock to correct the deficiencies in its Four-Factor Analyses for Combination Boilers Nos. 3 and 4 and Recovery Boilers Nos. 1 and 2, or the agency must correct those errors itself. As noted above, there are likely available, feasible, and cost-effective controls available to reduce SO_2 emissions from this facility. As a result, Florida DEP's proposal that only existing measures are necessary for this facility results in a SIP that

---

[137] SIP Supplement Explainer at 45, 47; Kordzi SIP Supplement Report at 13.
[138] SIP Supplement Explainer at 45.
[139] *Id.* at 47.
[140] *See supra* nn.70-71 and accompanying text; SIP Supplement Explainer at 47 ("Although the Department identified some issues with Westrock's cost effectiveness calculations, such as using a 4.75% interest rate, the weight of evidence demonstrates that installing these controls would still not be cost effective with a revised analysis.") (emphasis added); 82 Fed. Reg. at 3093 (explaining that, if a measure is found to be available, feasible, and cost-effective, it satisfies the four factors and is, by definition, necessary to make reasonable progress in the second planning period); 2021 Clarification Memo at 8 ("[W]hen the outcome of a four-factor analysis is a new measure, that measure is needed to remedy existing visibility impairment and is necessary to make reasonable progress.").
[141] SIP Supplement, App'x B, WestRock Panama City Four-Factor Analysis at 3-9, tbl.3-3 (Oct. 2020).
[142] *See supra* Section IV.A.
[143] SIP Supplement Explainer at 48.

fails to include emission reduction measures that are necessary to make reasonable progress towards achieving natural visibility at Class I areas, as required by the Clean Air Act and the RHR.

V. Florida DEP Must Revise the SIP Supplement to Ensure that Emission Limits Are Practically Enforceable.

To incorporate the limited additional and existing controls that Florida DEP determines are necessary to make reasonable progress into the Regional Haze SIP, Florida DEP proposes to incorporate provisions from eight different State-issued permits.[144] As discussed elsewhere in these comments and in the Conservation Organization's comments on the 2021 SIP Revision, there are numerous issues with Florida DEP's Four-Factor Analyses and likely additional control measures that Florida DEP must adopt to make reasonable progress in the second planning period. While we do not concede that the control measures Florida DEP proposes to adopt into its Regional Haze SIP are adequate, the agency must ensure that emission limitations it proposes to adopt into the SIP are practically enforceable.

A. The Legal Requirements for Practically Enforceable Emission Limits.

The Clean Air Act requires that all SIPs, including Regional Haze SIPs, contain elements sufficient to ensure emission limits are practically enforceable. CAA section 7410(a)(2) states that SIPs must (1) include "enforceable emission limitations and other control measures, means, or techniques. . . , as well as schedules and timetables for compliance, as may be necessary" and (2) provide "a program to provide for the enforcement of the measures described in [the SIP], and regulation of the modification and construction of any stationary source within the areas covered by the plan."[145] Similarly, section 7491 of the Act requires that that Regional Haze SIPs include "such emission limits, schedules of compliance and other reasonable measures" necessary to meet the goals of the Regional Haze Program."[146] Emission limits or standards incorporated into SIPs must apply to covered sources "on a continuous basis."[147] SIPs must also include provisions that give the State authority to include the required provisions in the SIP.[148] Additionally, emission limitations and the measures necessary for the SIP must be adopted as rules and regulations, and those rules and regulations must be included in the SIP and made publicly available during the notice and comment period on proposed SIPs.[149]

States must also include sufficient monitoring, recording, and recordkeeping requirements to allow states, EPA, and the public to determine whether sources are complying with applicable SIP requirements. The CAA provides that SIPs must require "the installation, maintenance, and replacement of equipment, and the implementation of other necessary steps . . . to monitor emissions from []sources," as well as "periodic reports on the nature and amounts of

---

[144] SIP Supplement Explainer at 3-4.
[145] 42 U.S.C. § 7410(a)(2).
[146] 42 U.S.C. § 7491(b)(2); 40 C.F.R. 51.308(f)(2).
[147] 42 U.S.C. § 7602(k) (defining "emission limitation" and "emission standard"); 40 C.F.R. § 51.100(z) (same).
[148] 40 C.F.R. § 51.231(a), (b).
[149] 40 C.F.R. § 51.281.

emissions and emissions-related data."[150] Implementing these statutory mandates, EPA's regulations require that SIPs include a "control strategy," which includes "[p]rocedures for monitoring compliance with each of the selected control measures."[151] Emission data must be correlated with applicable emission limitations or other measures, meaning the data must be presented in a way that clearly shows the relationship between the data and applicable emission limits.[152] Data collected by sources or otherwise obtained by states must be available to the public.[153]

To ensure sources properly monitor their emissions, SIPs must further specify applicable test methods to be used. States are required to include plan provisions providing for "[p]eriodic testing and inspection of stationary sources" and "[e]nforceable test methods for each emission limit specified in the plan."[154] EPA's regulations provide the "enforceable methods" states may use for the emission limits in the SIP and state that "[a]n alternative method" may only be used "following review and approval of that method by [EPA]."[155] Therefore, states cannot include SIP provisions that allow them to approve methods that are not approved by EPA. Moreover, the Act allows EPA to enforce against "any requirement or prohibition of an applicable implementation plan or permit" and any "requirement or prohibition of any rule, order, waiver or permit promulgated, issued, or approved under [the Act]."[156] Thus, the inclusion of unapproved alternative test methods could thwart EPA, or citizen,[157] enforcement.

In order for EPA to determine that a SIP submission is "complete" under the Act, the SIP must provide "[e]vidence that the plan contains emission limitations, work practice standards and recordkeeping/reporting requirements, where necessary, to ensure emission levels," as well as "[c]ompliance/enforcement strategies, including how compliance will be determined in

---

150 42 U.S.C. § 7410(a)(2)(F).
151 40 C.F.R. § 51.111(a)(1); *id.* § 51.230(f); *see also id.* § 51.210 (40 CFR part 51, subpart K, Source Surveillance, requiring SIPs to provide for monitoring the status of compliance with the regulations); *id.* § 51.214(a) (requiring, among other things, that SIPs contain "legally enforceable procedures" requiring regulated sources to "install, calibrate, maintain, and operate equipment for continuously monitoring and recording emissions"); *id.* § 51.214 (setting forth continuous emissions monitoring requirements).
152 40 C.F.R. § 51.116(c).
153 40 C.F.R. § 51.116(c); *id.* § 51.211 (providing that SIPs must include "legally enforceable procedures" for maintaining records and periodically reporting, including "[i]nformation on the nature and amount of emissions"); *id.* § 51.230(f) (requiring SIPs to provides states with the authority to make emissions monitoring data available to public).
154 40 C.F.R. § 51.212(a), (c) (The regulation specifies that "[a]s an enforceable method, States may use: (1) Any of the appropriate methods in appendix M to this part, Recommended Test Methods for State Implementation Plans; or (2) An alternative method following review and approval of that method by the Administrator; or (3) Any appropriate method in appendix A to 40 CFR part 60.")
155 40 C.F.R. § 51.212(c)(2).
156 42 U.S.C. §§ 7413(a)(1), (a)(3), (b)(1), (b)(2).
157 42 U.S.C. § 7604(a), (f) (defining the scope of citizen suit actions).

practice."[158] Where a proposed SIP fails to include practically enforceable requirements, EPA must disapprove the proposed SIP and promulgate a Federal Implementation Plan (FIP).[159]

B. Florida DEP Must Correct the Errors in the WestRock Fernandina Beach Permit No. 0890003-074-AC.

In its SIP Supplement, Florida DEP proposes to incorporate provisions from State-issued air construction Permit No. 0890003-074-AC for WestRock Fernandina Beach to add monitoring and recordkeeping requirements on coal consumption that were not included in the 2021 SIP Revision.[160] However, the permit provisions that Florida DEP proposes to incorporate are not practically enforceable. Florida DEP must address and correct errors in the WestRock Fernandina Beach permit to ensure its Regional Haze SIP satisfies the requirements of the Clean Air Act and RHR.

First, Permit No. 0890003-074-AC expired on December 31, 2022.[161] The SIP Supplement notes that the permit provisions proposed for inclusion in the SIP became effective on January 1, 2022.[162] Yet, because the permit expired in December 2022, the various permit provisions that Florida DEP proposes to incorporate into its SIP are also expired. Nowhere in the SIP Supplement does Florida DEP provide when the various permit provisions become effective for purposes of the Regional Haze SIP. Florida DEP, therefore, must explain how it has authority to include provisions from an expired permit in the SIP and explicitly state when the applicable permit provisions are effective for purposes of the SIP.[163]

Second, the permit provisions Florida DEP proposes to incorporate do not contain sufficient reporting requirements.[164] While the SIP Supplement suggests that there are "reporting" requirements in the Permit No. 0890003-074-AC,[165] a review of the referenced permit provisions the State proposes to include in the SIP shows that it does not actually require the owner/operator to report the coal usage records to the State. Instead, the permit merely requires that WestRock retain records onsite and make them available if Florida DEP specifically requests them.[166] It is not adequate that records are retained onsite. Rather, the records must be

---

[158] *See also* 40 C.F.R. § 51.103(a) (providing that "[t]he State makes an official plan submission to EPA only when the submission conforms to the requirements of appendix V to this part…").
[159] *See e.g.*, 79 Fed. Reg. 5032, 5058 (March 3, 2014) (EPA's final action explained that "as discussed in our proposed notices and elsewhere in this final notice, Wyoming's regional haze SIP lacks requirements for monitoring, recordkeeping, and reporting sufficient to ensure that the BART limits are enforceable and are met on a continuous basis." EPA's monitoring, recordkeeping and reporting FIP requirements codified at 40 C.F.R. § 52.2636); *see also* 78 Fed. Reg. 34,738, 34,788 (June 10, 2013) (EPA's proposed disapproval of the State of Wyoming's monitoring, recordkeeping, and reporting requirements because they were not practically enforceable.).
[160] SIP Supplement Explainer at 15.
[161] SIP Supplement, App'x A-2, Permit No. 0890003-074-AC, WestRock Fernandina Beach Mill at 1 (Dec. 16, 2021) (Permit Expired Dec. 31, 2022) [hereinafter "WestRock Fernandina Beach Mill Permit"].
[162] SIP Supplement Package at 22.
[163] 40 C.F.R. § 51.231(a), (b).
[164] 42 U.S.C. § 7410(a)(2)(F); 40 C.F.R. § 51.211.
[165] SIP Supplement Explainer at 15.
[166] WestRock Fernandina Beach Mill Permit at 6 ¶ 5b.

reported to the State to ensure that both the State and the public have an adequate opportunity to review records and ensure the facility is complying with its applicable emission limits.[167] Consistent with the Act and implementing regulations, Florida DEP must require that coal usage records and other relevant records are reported to the State on at least a semi-annual basis and specify how the reports shall be submitted to at Florida DEP.

Third, the permit emission limits that Florida DEP proposes to incorporate into the SIP do not clearly provide how the facility is to calculate its emissions. To demonstrate compliance with the applicable coal usage caps for Power Boiler No. 7, the permit requires that WestRock calculate its daily and 30-day rolling average coal usage "for each calendar day," excluding days of natural gas curtailment or supply interruption.[168] The permit does not define "calendar day." Without a definition WestRock could include all calendar days in a 30-day period, including those when the boiler is not operating. Florida DEP must revise the provision to clarify that WestRock must only include days when coal is combusted in the boiler.

C. Florida DEP Must Correct the Errors in the WestRock Panama City Mill Permit No. 0050009-47-AC.

In its SIP Supplement, Florida DEP proposes to incorporate provisions from State-issued air construction Permit No. 0050009-47-AC for WestRock Panama City.[169] However, the permit provisions that Florida DEP proposes to incorporate into the SIP are not practically enforceable. Florida DEP must address and correct errors in the WestRock Panama City permit to ensure its Regional Haze SIP satisfies the requirements of the Clean Air Act and implementing regulations.

As with the permit for WestRock Fernandina Beach, Florida DEP notes in the SIP Supplement that the permit provisions proposed for incorporation into the SIP became effective when the permit was issued on June 7, 2023.[170] However, Permit No. 0050009-47-AC for WestRock Panama City expired on December 31, 2023.[171] Thus, the permit provisions that Florida DEP proposes to include in the SIP are also expired and Florida DEP does not state anywhere in the SIP Supplement when the proposed provisions are to become effective for purposes of the Regional Haze SIP. Florida DEP must explain how it has authority to include provisions from an expired permit in the SIP and explicitly state when the applicable permit provisions are effective for purposes of the SIP.[172]

Additionally, the proposed permit provisions do not include sufficient reporting, record keeping, or monitoring requirements. In the SIP Supplement, Florida DEP determined that existing measures prohibiting the continued purchase of No. 6 fuel oil after the existing stock of that oil is exhausted for Recovery Boilers Nos. 1 and 2 and Combination Boilers Nos. 3 and 4 are

---

[167] *See e.g.* 42 U.S.C. § 7410(a)(2); 40 C.F.R. § 51.211; 42 U.S.C. § 7604(a), (f) (defining the scope of citizen suit actions).
[168] WestRock Fernandina Beach Mill Permit at 6 ¶ 5a.
[169] SIP Supplement Explainer at 49.
[170] SIP Supplement Package at 23-25.
[171] SIP Supplement, App'x A-3, Air Permit No. 0050009-047-AC, WestRock Panama City Mill at 1 (June 7, 2023) (Permit Expired Dec. 31, 2023) [hereinafter "WestRock Panama City Permit"].
[172] 40 C.F.R. § 51.231.

necessary for reasonable progress.[173] The agency also determined existing measures limiting (1) the maximum sulfur content to 0.75% by weight for No. 2 fuel oil fired at Combination Boilers Nos. 3 and 4, and (2) the coal usage to 125 tpd and the maximum sulfur content to 0.75% by weight for coal fired at Combination Boiler No. 4 are necessary for reasonable progress.[174] Yet, the corresponding permit provisions that Florida DEP proposes to incorporate into the SIP do not provide for adequate reporting to ensure WestRock complies with these measures. The proposed provisions for Recovery Boiler Nos. 1 and 2 only require that the facility retain records of fuel oil shipments and make those records available to Florida DEP if the agency requests them.[175]

Similarly, the proposed provisions for coal usage at Combination Boiler No. 4 only require that WestRock retain coal usage records and make them available to Florida DEP upon request.[176] As explained above, merely retaining records on site does not satisfy the requirements of the Clean Air Act or the implementing regulations.[177] Even worse still, the proposed fuel oil provisions for Combination Boilers Nos. 3 and 4 do not contain any reporting, record keeping, or monitoring requirements for fuel oil usage at either boiler.[178] Florida DEP must revise the SIP requirements so that the pertinent records (*e.g.*, shipment records regarding sulfur content, method(s) used for measuring sulfur content in the fuel oil, monitoring, recordkeeping and reporting regarding use of No. 6 fuel oil) are reported to the State on at least a semi-annual basis.

The proposed provisions similarly fail to specify the test methods required for assessing whether the fuel oil and coal fired at WestRock's boilers meet the sulfur content requirements noted above.[179] However, in contrast to the Panama City permit, the permit for the Georgia-Pacific Foley Mill identifies the applicable test methods for assessing the sulfur content of permitted fuels for that facility.[180] Florida DEP must treat facilities in the same manner.[181] Consequently, Florida DEP must specify the test methods that WestRock must use to determine the sulfur content of the permitted fuel oils and coal to be fired at the Recovery Boilers and Combination Boilers and ensure those test methods comply with the requirements of the Clean Air Act and its implementing regulations.[182]

---

[173] SIP Supplement Explainer at 46, 49.
[174] *Id.* at 46.
[175] WestRock Panama City Permit at 6 ¶ 3; SIP Supplement Package at 23-24.
[176] WestRock Panama City Permit at 9 ¶ 4; SIP Supplement Package at 25.
[177] *See supra* nn.150-153, 167 and accompanying text.
[178] WestRock Panama City Permit at 7 ¶ 2, 8 ¶ 2; SIP Supplement Package at 24-25.
[179] 40 C.F.R. § 51.212(c).
[180] SIP Supplement, Appendix A, Air Permit No. 1230001-121-AC, Georgia-Pacific Foley Mill, at 9-10 ¶¶ 11, 12, 13 14 (Oct. 20, 2023). (Permit Expires Dec. 31, 2024).
[181] *Nat'l Parks Conservation Ass'n v. U.S. Envtl. Prot. Agency*, 788 F.3d 1134, 1141, 1145 (9th Cir. 2015) (EPA's [and state's] actions must also be consistent; an internally inconsistent analysis is arbitrary and capricious) (citation omitted).
[182] 40 C.F.R. § 51.212(a), (c)(2).

Finally, while the permit references the definition of "PTE" in Rule 6-210.200,[183] as explained in these comments, the permit lacks the requirements to be practically enforceable (or "federal enforcement" as described in Florida's rule). The SIP may contain physical or operational limitations on the capacity of the emissions units to emit a pollutant, however, in order for the limitations to be practically or federally enforceable the type or amount of material combusted, stored, or processed, must be monitored, recorded and reported. As discussed above, the provisions of the permit that Florida DEP proposes to include in the SIP fail to include these required elements to be practically enforceable.

D. Florida DEP Must Correct the Errors in the Georgia-Pacific Foley Mill Permit No. 1230001-121-AC.

Florida DEP proposes to incorporate provisions from State-issued air construction Permit No. 1230001-121-AC for the Georgia-Pacific Foley Mill.[184] Again, the permit provisions that Florida DEP proposes to incorporate are not practically enforceable, and Florida DEP must correct the errors in that permit discussed below to comply with the requirements of the Clean Air Act and RHR.

1. Florida DEP Must Correct Errors in the Power Boiler No. 1 Provisions.

The proposed permit provisions for the Foley No. 1 Power Boiler are not sufficiently defined and include improper exemptions.

First, the permit provisions that Florida DEP proposes to incorporate into the SIP include vague exemptions allowing Power Boiler No. 1 to fire otherwise prohibited fuel types. As Florida DEP explains in the SIP Supplement, Power Boiler No. 1 is generally only allowed to fire natural gas.[185] However, the permit provisions that the agency proposes to incorporate allow Power Boiler No. 1 to fire "liquid fuels" if there are "physical mill problems."[186] Nothing in the permit or the SIP Supplement defines what constitutes "physical mill problems." Thus, the permit appears to allow Georgia-Pacific to operate Power Boiler No. 1 during malfunction events. Florida DEP must clarify what constitutes the category of events that fall within "physical mill problems" and set an alternative reasonable progress emission limitation that would apply to Power Boiler No. 1 when it operates during those events.

---

[183] The definition of PTE is found in Rule 6-210.200(247) ("The maximum capacity of an emission unit or facility to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the emissions unit or facility to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of an emission unit or facility."), https://www.epa.gov/system/files/documents/2021-12/62-210.pdf.
[184] SIP Supplement Package at 13-21.
[185] SIP Supplement Explainer at 24.
[186] SIP Supplement, App'x A-1, Air Permit No. 1230001-121-AC, Georgia-Pacific Foley Mill at 9 ¶ 8 (Oct. 20, 2023) (Permit Expires Dec. 31, 2024) [hereinafter "Georgia-Pacific Foley Mill Permit"]; SIP Supplement Package at 14.

Second, the proposed permit provisions would allow Georgia-Pacific to use undisclosed test methods to assess the sulfur content of permitted fuels for Power Boiler No. 1. As noted above, the SIP must provide appropriate test methods to assess whether covered sources are complying with applicable emission limits, and states cannot allow sources to use test methods that are not approved by EPA.[187] However, the permit provisions listing the applicable test methods for assessing the sulfur content of fuels fired at Power Boiler No. 1 would allow Florida DEP to approve of other methods not specifically listed.[188] Thus, Florida DEP must remove the provision that allows it to approve other test methods that are not currently included in the permit provision.

2. Florida DEP Must Correct Errors in the Bark Boilers Nos. 1 and 2 Provisions.

The proposed permit provisions for the Foley Bark Boilers Nos. 1 and 2 are not sufficiently defined and include improper exemptions.

Just as with the proposed permit provisions for Power Boiler No. 1, the permit provisions that Florida DEP proposes to incorporate for Bark Boilers Nos. 1 and 2 include vague exemptions that allow these boilers to fire prohibited fuels. Like Power Boiler No. 1, the Bark Boilers are generally only allowed to fire wood materials and natural gas.[189] However, the permit provisions Florida DEP proposes to incorporate for these Boilers again allow for firing of "liquid fuels" if there are "physical mill problems," (similarly, the permit allows Geogia-Pacific to avoid and by-pass the TRS pre-scrubber for maintenance, malfunction and undefined "operational issues')[190] but Florida DEP fails to define what constitutes "physical mill problems" in either the permit or the SIP Supplement. Florida DEP must clarify what constitutes the category of events that fall within "physical mill problems" and the alternative operating scenarios for the TRS pre-scrubber and must set an alternative reasonable progress emission limitation for these operations.

And just as with Power Boiler No. 1, Florida DEP proposes to incorporate permit provisions for the two Bark Boilers that allow Georgia-Pacific to use test methods to assess the sulfur content of fuels used to fire those boilers that EPA has not approved, in violation of the Clean Air Act and its implementing regulations.[191] Thus, Florida DEP must also remove the provision that allows it to approve other test methods not currently listed in the permit.

Florida DEP also proposes to incorporate other permit provisions for monitoring the existing wet scrubbers that reference material not included with the SIP Supplement. The "Wet Scrubber Parameter Monitoring" provision that Florida DEP determined is necessary for reasonable progress requires that Georgia-Pacific calibrate "[e]ach monitoring device . . . on the

---

[187] 40 C.F.R. § 51.212.
[188] Georgia-Pacific Foley Mill Permit at 9-10 ¶ 11 (providing that "[o]ther more recent or equivalent ASTM (American Society for Testing and Materials) methods or department-approved methods are also acceptable. No other methods may be used unless prior written approval is received from the Department").
[189] SIP Supplement Explainer at 28.
[190] Georgia-Pacific Foley Mill Permit at 10 ¶¶ 15, 17.
[191] *Id.* at 11 ¶ 20; 40 C.F.R. § 51.212.

scrubber water supply line . . . in accordance with the manufacturer's recommendations."[192] However, those recommendations are not included in the permit or the SIP Supplement. Calibration procedures are necessary for sources to demonstrate compliance with applicable emissions, and thus, are required for emission limits to be practically enforceable. Additionally, the public must be provided with an opportunity to review those materials to ensure that the Bark Boilers are complying with the applicable emission limits. Therefore, Florida DEP must include either the manufacturer's recommendations or specific calibration procedures in the permit provisions to be incorporated into the Regional Haze SIP for the wet scrubber monitoring devices.

3. Florida DEP Must Correct Errors in the Recovery Furnaces Nos. 2, 3 and 4 Provisions.

The proposed permit provisions for the Recovery Furnaces Nos. 2, 3, and 4 include improper exemptions or reference materials that are not included in the relevant permit provisions or the SIP Supplement.

Florida DEP again proposes to incorporate permit provisions into the SIP for the Recovery Furnaces that would allow the agency to approve test methods to assess the sulfur content of fuels fired at the furnaces that EPA has not approved.[193] For the same reasons discussed above, Florida DEP must remove the provision that allows it to approve other test methods not currently included in the permit provision.[194]

Additionally, Florida DEP proposes to incorporate permit provisions for the SO_2 CEMS for the Recovery Furnaces that reference materials that are not included in the permit or the SIP Supplement and do not provide any requirements for operation of the SO_2 CEMS. The "SO_2 CEMS" provisions provide that SO_2 CEMS for each furnace must be calibrated and maintained to meet quality assurance requirements contained in "Appendix D" of the permit.[195] Neither the permit nor the SIP Supplement include the referenced "Appendix D." Thus, the public cannot review and comment on those requirements, nor will the public be able to ensure that Georgia-Pacific complies with the quality assurance requirements using the Act's citizen enforcement authorities discussed above. Florida DEP must include Appendix D as part of the SIP. This same permit provision is also vague, merely specifying that "CEMS shall be installed and operated to monitor and record SO_2 emissions from each recovery furnace."[196] In accordance with the Act's implementing regulations (*e.g.*, 40 C.F.R. § 51.214(a)), Florida DEP must include in the SIP the specific operating requirements that the CEMS are subject to.

---

[192] Georgia-Pacific Foley Mill Permit at 11 ¶ 5; SIP Supplement Package at 18.
[193] Georgia-Pacific Foley Mill Permit at 13 ¶ 5; SIP Supplement Package at 20.
[194] 40 C.F.R. § 51.212.
[195] Georgia-Pacific Foley Mill Permit at 13 ¶ 7; SIP Supplement Package at 21.
[196] Georgia-Pacific Foley Mill Permit at 13 ¶ 7.

4. Florida DEP Must Correct Errors with the Reporting Requirements for All of the Foley Mill Units.

In addition to the emission unit-specific issues discussed above, the reporting requirements from the permit that Florida DEP proposes to incorporate into the SIP are inadequate for the Foley Mill units. As explained above, Florida DEP must include provisions in the SIP requiring that sources provide necessary records to the State on a regular basis.[197] However, the various permit provisions that Florida DEP proposes to incorporate into the SIP merely require that Georgia Pacific retain records onsite and make them available to the agency upon request and other provisions fail to include any recordkeeping and reporting requirements.[198] For example, the "Fuel Firing Records" provision that Florida DEP proposes to incorporate into the SIP for Power Boiler No. 1 requires only that Georgia-Pacific "maintain a written or electronic log" of monthly fuel usages and document all periods for gas curtailment, pipeline disruptions, or physical mill problems, but does not require that it actually provide any of these records to Florida DEP.[199] Similarly, for Bark Boiler Nos. 1 and 2, the "Wet Scrubber Parameter Monitoring" provisions that Florida DEP proposes to incorporate requires Georgia-Pacific to record readings for the wet scrubber and document any periods when the parameter monitor was not available for over an hour, but again does not require Georgia-Pacific to provide these records to the agency.[200] Florida DEP must revise the SIP requirements so that the pertinent records are all reported to the State on at least a semi-annual basis.

E. Florida DEP Must Correct the Errors in the Mosaic South Pierce Permit No. 1050055-037-AC.

While Florida DEP states that it only includes this permit in the SIP Supplement for informational purposes because EPA already approved the necessary permit provisions as part of the State's Startup, Shutdown, and Malfunction (SSM) SIP,[201] EPA approved these provisions to satisfy other requirements under the Clean Air Act. As Florida DEP determined in the SIP Supplement, existing measures for Mosaic South Pierce—namely, existing SO_2 emission limits for Sulfuric Acid Plants 10 and 11 and associated monitoring, reporting, and record keeping requirements—are necessary for to make reasonable progress toward the national visibility goal under the Regional Haze Program.[202] Thus, Florida DEP must correct errors in the applicable permit provisions to ensure that its Regional Haze SIP includes practically enforceable limits.

First, Permit No. 1050055-037-AC expired on June 30, 2023.[203] Because the permit is already expired, the various permit provisions that Florida DEP proposes to incorporate into its

[197] *See supra* nn.150-153, 167 and accompanying text.

[198] *See e.g.* Georgia-Pacific Foley Mill Permit: **TRS Pre-Scrubber Parameter Monitoring**: at 9 ¶ 7 (no requirement to report records); **No. 1 Power Boiler**: at 9 ¶ 8 (use of flow meters to monitor and record fuel usage, no requirement to report), at 9 ¶ 9 (sulfur content restriction for fuel oil, no requirement to report), at 9 ¶ 10 (records for combusting LVHC NCG gases and reason why No. 1 Bark Boiler unavailable, no requirement to report), at 10 ¶ 12 (requirement for testing fuel sulfur content, no requirement to report), at 10 ¶ 13 (requirement for recording liquid fuel delivery, no requirement to report), at 10 ¶ 14 (fuel firing records, no requirement to report); **No. 1 Power Boiler and No. 1 Bark Boiler**: at 10 ¶ 15 (use of flow meters to monitor and record fuel usage, no requirement to report), at 10 ¶ 16 (sulfur content restriction for fuel oil, no requirement to report), at 10 ¶ 17 (records for combusting

Regional Haze SIP are also expired. Florida DEP, therefore, must explain how it has authority to include provisions from an expired permit in the Regional Haze SIP.[204]

Second, the reporting requirements from the permit that Florida DEP proposes to incorporate into the SIP are inadequate. The permit provisions only require Mosaic South Pierce to "keep records" documenting its compliance with the applicable SO_2 limits, but does not require that the facility actually provide those records to Florida DEP on a regular basis,[205] in violation of the Clean Air Act and its implementing regulations.[206] Florida DEP must revise the SIP requirements so that the pertinent records are all reported to the State on at least a semi-annual basis. The recordkeeping provisions also provide that Mosaic South Pierce prepare required records in accordance with the requirements of "Appendix D."[207] However, that appendix is not included in the permit or the SIP Supplement for review and comment. Florida DEP must include Appendix D as part of the SIP.

Third, because both of Mosaic South Pierce's Sulfuric Acid Plants have a "design production rate of 3,000 tons per day of sulfuric acid,"[208] the plants are subject to requirements for continuous SO_2 monitoring systems as provided in 40 C.F.R Part 51.[209] Yet, these requirements are not reflected in any of the permit conditions that Florida DEP propose to incorporate into the SIP for Mosaic South Pierce.[210] Florida DEP must include the detailed CEMS requirements in the SIP.

LVHC NCG gases and reason why TRS pre-scrubber unavailable, no requirement to report); at 10 ¶ 18 (no recording or reporting requirements for the wet venturi scrubber operations); **No. 1 Power Boiler & No. 1 Bark Boiler**: at 11 ¶ 21 (sulfur content restriction for fuel oil, no requirement to report), at 11 ¶ 22 (no requirement to report wet scrubber parameter monitoring records), at 11 ¶ 23 (requirement for recording liquid fuel delivery, no requirement to report), 1at 1 ¶ 24 (fuel firing records, no requirement to report), at 11 ¶ 25 (no requirement to report wet scrubber parameter compliance information); **Nos. 2, 3, and 4 Recovery Furnaces**: at 12 ¶ 2 (use of flow meters to monitor and record fuel usage, no requirement to report), at 12 ¶ 4 (no requirements on how to calculate, record and report SO_2 emission cap), at 13 ¶ 6 (requirement for testing fuel sulfur content, no requirement to report), at 13 ¶ 7 (no requirement to report SO_2 CEMS data for SIP compliance), at 13 ¶ 8 (requirement for recording liquid fuel delivery, no requirement to report), at 13 ¶ 9 (fuel firing records, no requirement to report); SIP Supplement Package at 13-22.

[199] *Id.* at 10 ¶ 14; SIP Supplement Package at 16.

[200] *Id.* at 11 ¶ 22; SIP Supplement Package at 18.

[201] SIP Supplement Explainer at 6 (referencing 88 Fed. Reg. 51,702 (Aug. 4, 2023)).

[202] *Id.* at 6.

[203] SIP Supplement, App'x A-7, Permit No. 1050055-037-AC, Mosaic South Pierce at 1 (Sept. 22, 2022) (Permit Expired June 30, 2023) [hereinafter "Mosaic South Pierce Permit"].

[204] 40 C.F.R. § 51.231(a), (b).

[205] Mosaic South Pierce Permit at 5-6 ¶ 6; SIP Supplement Package at 29.

[206] *See supra* nn.150-153, 167 and accompanying text.

[207] Mosaic South Pierce Permit at 5-6 ¶ 6; SIP Supplement Package at 29.

[208] Mosaic South Pierce Permit at 6 ¶ 6; SIP Supplement Package at 29.

[209] Appendix P to Part 51, ¶ 2.3 ("shall install, calibrate, maintain and operate a continuous monitoring system for the measurement of sulfur dioxide which meets the performance specifications of paragraph 3.1.3 for each sulfuric acid producing facility within such plant.")

[210] Mosaic South Pierce Permit at 5-6.

F. Florida DEP Must Correct the Errors in the JEA Northside Units 1 and 2 Permit No. 0310045-059-AC and JEA Northside Unit 3 Permit No. 0310045-062.

Florida DEP proposes to incorporate provisions from State-issued air construction Permit Nos. 0310045-059-AC and 0310045-062-AC for JEA Northside Units 1, 2, and 3.[211] However, the permit provisions that Florida DEP proposes to incorporate into the SIP are not practically enforceable. Florida DEP must address and correct errors in the JEA Northside permits to ensure its Regional Haze SIP satisfies the requirements of the Clean Air Act and implementing regulations.

As an initial matter, Permit No. 0310045-059-AC for JEA Northside Units 1 and 2 expired on June 30, 2023.[212] Because that permit is already expired, the various permit provisions that Florida DEP proposes to incorporate into its Regional Haze SIP are also expired. Florida DEP must explain how it has authority to include provisions from an expired permit in the SIP.[213]

In any event, the permit provision providing the MATS SO_2 emission limits for JEA Northside Units 1 and 2 that Florida DEP proposes to incorporate into the SIP is not practically enforceable. That provision provides that compliance with the MATS SO_2 emission limits must be "demonstrated as determined in 40 CFR 63.10021(a) and (b) of the MATS rule."[214] Florida DEP's overarching reference to 40 C.F.R. § 63.10021(a) does not specify which of the requirements in that regulation apply to this facility. Notably, there are four different tables in the rule that contain emission limits, operating limits, and work practice standards.[215] The rule also includes monitoring requirements in two additional tables.[216] Similarly, the permit provision does not explain which provisions in 40 C.F.R. § 63.10021(b)[217] apply to the facility. Florida DEP must revise this permit provision to explain exactly which portions of 40 C.F.R. § 63.10021(a) and (b) it proposes to incorporate into the Regional Haze SIP.

---

[211] SIP Supplement Package at 25-27.
[212] SIP Supplement, App'x A-4, Air Permit No. 0310045-059-AC, JEA Northside Units 1 and 2 at 1 (Feb. 16, 2023) (Permit expired June 30, 2023) [hereinafter "JEA Northside Units 1 and 2 Permit"].
[213] 40 C.F.R. § 51.231(a), (b).
[214] JEA Northside Units 1 and 2 Permit at 6 ¶ 2; SIP Supplement Package at 26.
[215] 40 C.F.R. § 63.10021(a) ("You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.").
[216] *Id.*
[217] 40 C.F.R. § 63.10021(b) ("Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.")

The permit provisions that Florida DEP proposes to incorporate for JEA Northside Unit 3 also do not meet the applicable reporting and recording keeping requirements under the Clean Air Act. The "Fuel Oil Sulfur Records" provision in Permit No. 0310045-062-AC for Unit 3 requires JEA Northside to maintain records of each shipment of fuel oil and make them available to Florida DEP upon request.[218] Yet, it is not sufficient for Florida DEP to merely maintain these records onsite.[219] Florida DEP must require that these fuel shipment records and other relevant records are reported to the State on at least a semi-annual basis and specify how the reports shall be submitted to at Florida DEP.

G. Florida DEP Must Correct the Errors in the Nutrien White Springs Permit No. 0470002-132-AC.

Just as with Mosaic South Pierce, Florida DEP states that it only includes this permit in the SIP Supplement for informational purposes because EPA already approved the necessary permit provisions as part of the State's SSM SIP.[220] However, EPA approved these provisions to satisfy other requirements under the Clean Air Act, and Florida DEP determined that existing measures—namely, existing SO_2 emission limits for Sulfuric Acid Plants E and F and accompanying monitoring, recording, and recordkeeping requirements—are necessary to make reasonable progress toward the national visibility goal under the Regional Haze Program.[221] Thus, Florida DEP must correct errors in the applicable permit provisions to ensure that its Regional Haze SIP includes practically enforceable limits.

First, because both of Nutrien White Spring's Sulfuric Acid Plants are "2,750 tons per day" plants,[222] they are subject to requirements for continuous SO_2 monitoring systems as provided in 40 C.F.R Part 51.[223] Yet, these requirements are not reflected in any of the permit conditions that Florida DEP proposes to incorporate into the Regional Haze SIP.[224]

Second, the reporting requirements from the permit that Florida DEP proposes to incorporate into the SIP are inadequate. The relevant permit provision only requires Nutrien White Springs to "keep records" documenting its compliance with the applicable SO_2 limits, but does not require that the facility actually provide those records to Florida DEP on a regular basis,[225] in violation of the Clean Air Act and its implementing regulations.[226] Florida DEP must revise the SIP requirements so that the pertinent records for this and other provisions are all

[218] SIP Supplement, App'x A-5, Air Permit No. 0310045-062, JEA Northside Unit 3 at 4 ¶ 7 (Aug. 24, 2023).
[219] *See supra* nn.150-153, 167 and accompanying text.
[220] SIP Supplement Explainer at 7 (referencing 88 Fed. Reg. 51,702 (Aug. 4, 2023)).
[221] *Id.*
[222] SIP Supplement, App'x A-6, Air Permit No. 0470002-132-AC, White Springs Agricultural Chemicals, Inc. Swannee River and Swift Creek Complex at 6 (Aug. 24, 2023) (Permit expired Dec. 31, 2022) [hereinafter "Nutrien White Springs Permit"].
[223] Appendix P to Part 51, ¶ 2.3 ("shall install, calibrate, maintain and operate a continuous monitoring system for the measurement of sulfur dioxide which meets the performance specifications of paragraph 3.1.3 for each sulfuric acid producing facility within such plant.").
[224] Nutrien White Springs Permit at 3-6; SIP Supplement Package at 27-28.
[225] Nutrien White Springs Permit at 6 ¶ 5; SIP Supplement Package at 28.
[226] *See supra* nn.150-52, 167 and accompanying text.

reported to the State on at least a semi-annual basis. The recordkeeping provision also provides that Nutrien White Springs prepare records in accordance with the requirements of "Appendix D."[227] However, that appendix is not included in the permit or the SIP Supplement for review and comment. Florida DEP must include Appendix D as part of the SIP.

VI. Florida DEP Did Not Engage in Meaningful FLM Consultation on the SIP Supplement.

The consultation process with FLMs is a critical step in the SIP development process. FLMs contribute valuable expertise in managing the very Class I resources that the Regional Haze Program was created to protect. States must consult with FLMs on (1) their assessment of visibility impairment in impacted Class I areas and (2) their recommendations on the development and implementation of strategies to address such impairment.[228] In order for the public and EPA to assess whether states have satisfied their consultation requirements, states must also document the timing and content of their consultation with FLMs, including a description of how states addressed any comments provided by FLMs.[229] Thus, the FLM consultation process is not a mere box checking exercise. Rather, it is a mandatory, iterative, and substantive process, requiring Florida DEP to meaningfully consider and incorporate into its SIP Revision the FLMs' concerns.

Here, although Florida DEP provided FLMs an opportunity to consult on the SIP Supplement, the agency did not meaningfully engage with or respond to the FLMs' recommendations. As noted above, FLMs recommended that Florida DEP require a Four-Factor Analysis for Mosaic South Pierce that includes a review of post-process scrubber controls.[230] Florida DEP's only response to the FLM recommendation was a cursory claim that the use of post-process scrubbers were "not considered to be cost-effective."[231] Florida DEP does not explain whether it actually conducted any kind of cost analysis and does not provide any documentation to support its conclusion that post-process controls are not cost effective for Mosaic South Pierce. The agency's conclusory response without any explanation or support does not meet the RHR's requirement to "descri[be] how it addressed any comments provided by the [FLMs]."[232] To satisfy the Clean Air Act and RHR's requirement to meaningfully engage in FLM consultation, Florida DEP must either require Mosaic South Pierce to conduct a Four-Factor Analysis, including a review of post-process controls, or conduct that analysis itself.

---

[227] Nutrien White Springs Permit at 6 ¶ 5; SIP Supplement Package at 28.
[228] 40 C.F.R. § 51.308(i)(2)(i)-(ii).
[229] *Id.* § 51.308(i)(3).
[230] SIP Supplement Package at 49-50.
[231] *Id.* at 51.
[232] 40 C.F.R. § 51.308(i)(3).

VII. As With the 2021 SIP Revision, Florida DEP Entirely Ignores Environmental Justice Considerations in its SIP Supplement.

The Conservation Organizations explained in their comments on the 2021 SIP Revision that Florida DEP should have, but failed to, incorporate environmental justice considerations into its draft SIP.[233] Florida DEP has ample available resources to (1) analyze the disparate impacts of haze-forming pollution on low-income communities and communities of color throughout the state, and (2) take action to minimize the harms caused by this pollution through its Regional Haze SIP.[234] EPA has also encouraged states incorporate environmental justice and equity into their technical analyses, both when determining which sources to select for a Four-Factor Analysis and when determining what reasonable progress measures to require for a source.[235]

Instead, Florida DEP has entirely ignored this issue. Nowhere in the 2021 SIP Revision or the SIP Supplement does Florida DEP even mention environmental justice. Yet, haze-forming emissions from facilities included in the SIP Supplement likely disparately harm communities in Florida. For example, EPA EJScreen data shows that the population living within 20 miles of JEA Northside is above the 50th percentile compared to the rest of the state for every environmental justice index, including particulate matter (80th percentile) and ozone (80th percentile).[236] The population surrounding the Nutrien White Springs facility similarly ranks high on EPA EJScreen's environmental justice indices, at the 73rd percentile for particulate matter and 69th percentile for ozone compared to the rest of the state.[237] Florida DEP should take advantage of the unique opportunity provided by its SIP action to advance environmental justice and equity in the state.

CONCLUSION

We appreciate Florida DEP's consideration of these comments and ask that the agency revise its SIP Supplement, as well as its 2021 SIP Revision, to correct the deficiencies described herein and attached. Please do not hesitate to contact us with any questions.

Sincerely,

Melissa E. Abdo, Ph.D.
Sun Coast Regional Director
National Parks Conservation Association
4429 Hollywood Blvd. # 814990
Hollywood, FL 33081
mabdo@npca.org

Caitlin Miller
Associate General Counsel, Clean Air and Climate
National Parks Conservation Association
P.O. Box 101705
Denver, CO 80250
cmiller@npca.org

---

[233] Conservation Orgs' 2021 SIP Revision Comments at 39-43.
[234] *Id.* at 40-41, 43.
[235] 2021 Clarification Memo at 16; *see also* Conservation Orgs' 2021 SIP Revision Comments at 42.
[236] U.S. Env't Prot. Agency, EJScreen Community Report: 20 Miles Ring Centered at 30.418484, -81.552898 (Feb. 15, 2024) (attached as Ex. 6).
[237] U.S. Env't Prot. Agency, EJScreen Community Report: 20 Miles Ring Centered at 30.408172, -82.787390 (Feb. 15, 2024) (attached as Ex. 7).

Susannah Randolph
Florida Chapter Director
Sierra Club
415 1st Avenue North
St. Petersburg, FL 33701
susannah.randolph@sierraclub.org

Sara L. Laumann
Principal
Laumann Legal, LLC
3800 Buchtel Blvd. S. #100236
Denver, CO 80210
sara@laumannlegal.com
Counsel for NPCA

Philip A. Francis Jr.
Chair
Coalition to Protect America's National Parks
2 Massachusetts Ave NE, Unit 77436
Washington, DC 20013
editor@protectnps.org

cc: Jeaneanne Gettle, Acting Regional Administrator, EPA Region 4, Gettle.Jeaneanne@epa.gov

Sarah Taft, Acting Director, Air and Radiation Division, EPA Region 4, Taft.Sarah@epa.gov

Anthony Toney, Deputy Director, Air and Radiation Division, EPA Region 4, Toney.Anthony@epa.gov

Lynorae Benjamin, Chief, Air Planning & Implementation Branch, Air and Radiation Division, EPA Region 4, Benjamin.Lynorae@epa.gov

Michele Notarianni, Air and Radiation Division, EPA Region 4, Notarianni.Michele@epa.gov

Pearlene Williams-Miles, Air and Radiation Division, EPA Region 4, WilliamsMiles.Pearlene@epa.gov

Daphne Wilson, Environmental Engineer, Environmental Justice Liaison, EPA Region 4, Wilson.daphne@epa.gov

Brian Timin, Air Quality Policy Division, Office of Air Quality Planning and Standards, Timin.Brian@epa.gov

Vera Kornylak, Air Quality Policy Division, Office of Air Quality Planning and Standards, Kornylak.Vera@epa.gov

List of Exhibits:

Exhibits can be accessed here: https://drive.google.com/drive/folders/10aihco3jO-lbOjFVUufaCr8_9qcL5UZV?usp=sharing

1. Kordzi, Joe, A Review of the Florida Regional Haze State Implementation Plan Supplement of January 2024 (Feb. 2024).

2. In the Matter of Proposed Revisions to Regulation Number 23, Colo. Dep't of Pub. Health & Env't, Air Pollution Control Div., Prehearing Statement (Oct. 7, 2021).

3. Nev. Div. of Env't Prot., Nevada Regional Haze State Implementation Plan for the Second Planning Period (Aug. 2022).

4. NM Env't Dep't and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2.

5. Letter with Enclosure from Kay T. Prince, Chief, Air Planning Branch, Region 4, U.S. Env't Prot. Agency, to Sheila Holman, Div. of Air Quality, NC Dep't of Env't and Natural Resources, EPA Comments on BART for the Blue Ridge Paper – Canton Mill (Jan. 31, 2007).

6. U.S. Env't Prot. Agency, EJScreen Community Report JEA Northside: 20 Miles Ring Centered at 30.418484, -81.552898 (Feb. 15, 2024).

7. U.S. Env't Prot. Agency, EJScreen Community Report Nutrien White Spring: 20 Miles Ring Centered at 30.408172, -82.787390 (Feb. 15, 2024).

Exhibit 1

A Review of the Florida Regional Haze State Implementation Plan Supplement of January 2024

Prepared by

Joe Kordzi, Consultant

On behalf of

National Parks Conservation Association

February 2024

Table of Contents

1 Introduction

This is a report concerning a review of the January 2024 Florida Regional Haze State Implementation Plan (SIP) Supplement.[1] A previous 2021 report covered the initial SIP submission (hereafter referred to as the "2021 Report").[2] Unless otherwise referenced however, the present report only focuses on the 2024 SIP supplement documents.

2 FL DEP Should Combine its Two Main Documents

Confusingly, the Florida Department of Environmental Protection (FL DEP) provides two main documents, referenced above in the first footnote. Both documents are referred to internally as a SIP supplement, have very similar names and the same issuance date, and appear to contain different elements of a complete SIP submission. However, neither document references the other, nor is there any clear distinction between the contents of one versus the other.

The first document is entitled, "State of Florida Department Of Environmental Protection, Supplement to Florida Regional Haze Plan for the Second Implementation Period for Florida Class I Areas, Pre-Hearing Submittal, January 19, 2024. This document is 51 pdf pages in length and does not have a table of contents. As it appears to focus on language revisions (albeit with little documentation) to specific sections of the original SIP, of the SIP actions proposed by FL DEP, it is hereafter referred to as the "SIP Revision" Document. Instead of wholesale replacement of sections, FL DEP should use redline strikeout to identify the changes made to its 2021 SIP.

The second document is entitled, "State of Florida Department of Environmental Protection, Proposed Revision to State Implementation Plan, Submittal Number 2024-01, Supplement to Florida Regional Haze Plan, Pre-Hearing Submittal, January 19, 2024." This document is 58 pdf pages in length and does have a table of contents. As it appears to provide additional explanations of actions FL DEP is proposing to take, it is hereafter known as the "SIP Explanation" Document.

A call to FL DEP staff resulted in the explanation that both documents are to be submitted to EPA but that the one containing permit limits would be incorporated into the SIP. Notwithstanding the number of deficiencies in this SIP supplement noted in this report, both documents contain some of the elements required of a SIP submittal (or a supplement to one). Consequently, the public must review both documents, which results in the process being unnecessarily cumbersome. Therefore, FL DEP should combine these documents.

---

[1] There are two main documents: (1) State of Florida Department Of Environmental Protection, Supplement to Florida Regional Haze Plan for the Second Implementation Period for Florida Class I Areas, Pre-Hearing Submittal, January 19, 2024, and (2) State of Florida Department of Environmental Protection, Proposed Revision to State Implementation Plan, Submittal Number 2024-01, Supplement to Florida Regional Haze Plan, Pre-Hearing Submittal, January 19, 2024.
Available here: https://floridadep.gov/air/air-business-planning/content/florida%E2%80%99s-supplemental-amendment-previously-proposed-regional-haze

[2] A Review of the Florida Regional Haze State Implementation Plan, Prepared by Joe Kordzi, Consultant, On behalf of National Parks Conservation Association and the Sierra Club, July 2021.

3 FL DEP Must Require Better Documentation

As discussed in the 2021 Report and in this report, there are numerous instances in which FL DEP fails to either require that its sources provide adequate documentation of claims of figures relating to cost items, technical feasibility of controls, control performance, and similar issues that relate to its long-term strategy. FL DEP has failed to correct this pervasive lack of documentation in its SIP supplement.

Unsupported statements do not rise to the level of documentation required by the Regional Haze Regulations. Adequate documentation for these claims is required by Section 51.308(f), which requires that Florida's SIP must include "supporting documentation for all required analyses." In addition, section 51.308(f)(2)(iii) requires that Florida's SIP "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."

In its 2017 revision to the Regional Haze Rule, EPA specifically emphasized the need for this type of documentation:[3]

> We are changing proposed 40 CFR 51.308(f)(2)(iv), regarding documentation requirements, ... to "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I area it affects." The purpose of this provision is to require states to document all of the information on which they rely to develop their long-term strategies, which will primarily be information used to conduct the four-factor analysis. Therefore, in addition to modeling, monitoring and emissions information, we are making it explicit that states must also submit the cost and engineering information on which they are relying to evaluate the costs of compliance, the time necessary for compliance, the energy and non-air quality impacts of compliance and the remaining useful lives of sources.

The Regional Haze Guidance reinforces this point:[4]

> As part of meeting the requirement of the Regional Haze Rule for the state to document the cost and engineering information on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress (40 CFR 51.308(f)(2)(iii)), every source-specific cost estimate used to support an analysis of control measures must be documented in the SIP. If information about a source has been asserted to be confidential, we recommend the state consult with its EPA Regional office regarding whether such

[3] See 82 FR 3096 (January 10, 2017) (emphasis added).
[4] See Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003 August 2019. Hereafter referred to as "Regional Haze Guidance," or "the Guidance.". Page 32.

> confidentiality is appropriate and allowed under the CAA and if so how it can be reconciled with the need for adequate documentation of the basis for the SIP.

FL DEP must therefore correct these fundamental failures in documentation in its SIP. Unless these issues are addressed, FL DEP cannot satisfy the above noted documentation requirements.

4 FL DEP Must Provide Sound Reasoning for Rejecting Cost-Effective Controls

Notwithstanding the numerous problems identified in the control cost analyses presented in both the 2021 Report and this report, a number of cost-effective controls have been identified, even accepting FL DEP's own figures. For example, FL DEP indicates on page 38 of the SIP Revisions Document that the cost-effectiveness of installing a wet scrubber on the three Foley recovery furnaces would range from $5,197/ton to $7,779/ton. On page 44 of the SIP Revisions Document FL DEP indicates that the cost-effectiveness of increasing caustic to the existing wet scrubber for the Westrock Panama City No. 4 Boiler would be $6,816/ton. On page 13 of the SIP Revisions Document, FL DEP indicates that the cost-effectiveness of removing all coal firing in the Westrock Fernandina Beach No. 7 Power Boiler would be $7,374 per ton. In all these cases, FL DEP simply states that it does not find these controls to be cost-effective. No reasoning has been provided to support these conclusions.

As a comparison, in its Good Neighbor Rule, EPA recently found that $7,500/ton and $11,000/ton were reasonable cost-effectiveness thresholds for NOx controls for non-EGU and EGU sources, respectively.[5]

FL DEP must come to terms with the reality that as the Regional Haze Program progresses, making continued progress will require controlling sources that result in smaller emissions reductions at higher costs. Therefore, rejecting controls that may be above acceptability thresholds from the first planning period will not place Florida on a sustainable path to achieving the national goal of a return to natural visibility by 2064, or in fact any timeframe. This is reflected in EPA's reasoning in the recent Good Neighbor Rule, in which EPA responds to a comment noting that EPA's $7,500/ton marginal cost threshold for non-EGUs is much higher than the $2,000/ton threshold used in the 2021 Revised CSAPR Update Rule. EPA states:[6]

> [T]he $7,500 marginal cost-per-ton threshold is higher than the cost-per-ton value used in the Revised Cross-State Air Pollution Rule Update because that rulemaking assessed significant contribution for the less protective 2008 ozone NAAQS, and it is reasonable when assessing significant contribution associated with the more protective 2015 ozone NAAQS, that a potentially more costly universe of emissions controls and related potential reductions should be included in the analysis.

Thus, EPA reasons that because it is addressing a stricter standard, a previously lower cost-effectiveness threshold that was used to address a less stringent standard is no longer appropriate. This is completely analogous with the state of the Regional Haze Rule. As the program

5 See he Good Neighbor Final Rule 88 FR 36746(June 5, 2023).
6 Ibid., 88 FR 36740 (June 5, 2023).

progresses through successive planning periods and progress is made, the "standards," reflected in the decreasing Uniform Rate of Progress, become more stringent. Therefore more costly controls must be considered in order to continue to make progress.

Consequently, FL DEP must reassess its position. It must either require these controls or provide sound, well-reasoned explanations for rejecting them.

5 FL DEP's Effective Controls Analyses Supplement is Inadequate

As indicated in Section 5 of the 2021 Report, FL DEP has made a number of errors in wrongly exempting sources from four-factor analyses based on its contention they are already "effectively controlled." This section critiques its supplements to this part of its SIP.

One basic flaw in FL DEP's original SIP analysis, reinforced on page 5 of the SIP Revisions Document, is its improper conclusion in Section 7.4 of its SIP, that it should focus on SO_2 reductions only in the second planning period. As indicated in the 2021 Report, there are many demonstrated opportunities for likely cost-effective NOx controls that FL DEP must assess.

5.1 The Mosaic South Pierce Effective Control Demonstration is not Acceptable

On page 5 of the SIP Revisions Document, FL DEP states that it found an effectively controlled demonstration for the Mosaic South Pierce acceptable, concluding that it is unlikely that additional controls would be identified as part of a four-factor analysis. However, as is indicated in many places in the 2021 Report, *the fact that a source has installed the most effective controls is no guarantee that it operates those controls in the most effective manner possible.*[7]

In this case, FL DEP concludes that because the South Pierce Sulfuric Acid Plants employ particular types of double absorption sulfuric acid systems, discussed in Appendix B.4, Mosaic's four-factor analysis requirements are satisfied. First, as is noted in the 2021 Report in Section 6.1, the RBLC does not constitute the last word on the technical feasibility of controls for the Regional Haze Program. The fact that a control cannot be found in the RBLC does not mean that it (1) has not been installed on a similar source, (2) has not operated more efficiently than is represented by RBLC information, or (3) is otherwise not technically feasible. EPA discusses what it means by technical feasibility in the BART Rule:[8]

> Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if the source owner may obtain it through

[7] See Section 5 of the 2021 Report for a detailed discussion of how FL DEP has misinterpreted EPA's discussion of effective controls in its Regional Haze Guidance, and wrongly used that misinterpretation to exempt sources from four-factor analyses.

[8] See the BART Rule, 70 FR 39165 (July 6, 2005). Note that on 70 FR 39164, EPA provides a listing of many sources of information, in addition to the RBLC, that can be consulted on the question of technical feasibility.

> commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is ''applicable'' if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

In other words, the RBLC can be used to identify controls that have been found to be technically feasible on similar sources, but it should not be used to exclude technically feasible controls that have been installed on similar sources merely because those instances are not recorded in its database.

Second, as the National Park Service (NPS) notes in its comments on pdf page 49 of the SIP Explanation Document, Mosaic does not even fully utilize what information is present in the RBLC. As the NPS indicates:

> Based on our review of four-factor analyses for other sulfuric acid plants, the Mosaic RBLC database search is missing numerous examples of dual absorption sulfuric acid plants with lower lb/ton SO_2 limits. This includes several facilities with additional post-process controls, including scrubbers (i.e., hydrogen peroxide or caustic scrubbers) and/or mist eliminators *that have limits as low as 0.15 lb SO_2/ton H_2SO_4* [emphasis added]. For reference an RBLC database search that was included with the ITAFOS Conda, Soda Springs four-factor analysis review in the Idaho Regional Haze SIP for the 2nd Planning Period (June 2022) is attached.
>
> Based on this RBLC data, the Idaho Department of Environmental Quality (IDEQ) requested a four-factor analysis from the ITAFOS sulfuric acid plant to evaluate additional SO_2 controls. Wet flue gas desulfurization, hydrogen peroxide scrubbers, and dry sorbent injection/caustic scrubbers were all found to be technically feasible. (IDEQ requested that the company also evaluate ozone scrubbers, which are reflected in the RBLC, but the requested analysis was not provided.)
>
> IDEQ also requested that the company obtain vendor quotes for hydrogen peroxide and caustic scrubbers, which were submitted along with the four-factor analysis. NPS review of this information finds that post-process scrubbers may be a cost-effective control option for double absorption sulfuric acid plants. We recommend that Florida DEP consider this information when evaluating the effective control demonstration from Mosaic South Pierce.

Thus, it appears that Mosaic did not consider the full complement of the RBLC database and controls evaluated by another state agency for a similar plant. FL DEP's response on page 51 of the SIP Explanation Document to the NPS comments is "[t]he Department reviewed this comment and determined that the use of post-process scrubbers for the dual adsorption process sulfuric acid plant at Mosaic South Pierce was not considered to be cost-effective for the facility." No actual documented and reasoned determination for this position is present in the

SIP supplement. Thus, FL DEP must require that the Mosaic South Pierce facility undergo a four-factor analysis. As discussed above, this must also consider NOx controls.

5.2 The Nutrien White Springs Facility Must Receive Four-Factor Analyses

On page 6 of the SIP Revision Document, FL DEP states that it is including in its SIP additional SO_2 permitting limits from Permit Nos. 0470002-122-AC and 0470002-132-AC, issued on December 21, 2018 and September 22, 2022, respectively, for Sulfuric Acid Plants Nos. E and F and that these limits represent reasonable progress.

As indicated in the 2021 Report, FL DEP has not demonstrated that these then proposed limits represent reasonable progress. Also, FL DEP must include its 840 lbs/hr SO_2 cap on SAPs E and F in this demonstration, particularly as to whether this cap has any determinative effect on SO_2 emissions. Simply assuming that upgrades required from a consent decree are consistent with prior BACT determinations is no substitute for a proper four-factor analysis. This is made clear by information cited in the 2021 Report: (1) the cited consent decree itself indicates that limits required of other similar Sulfuric Acid Plants, are lower[9] and (2) as Nutrien itself notes in its July 8, 2020, reply to FL DEP, the Rhodia Plant in Houston has a limit much lower that White Springs.[10] Thus, FL DEP has not demonstrated that the Nutrien White Springs Facility is effectively controlled and must subject that facility to a proper four-factor analysis.

5.3 The JEA Northside Units 1 and 2 Must Receive Four-Factor Analyses

On page 7 of the SIP Revision Document, FL DEP states that it is supplementing its effective controls analysis for JEA Northside Units 1 and 2 to include the facility's MATS limit, which FL DEP uses as an excuse to not assess these units for SO_2. On page 26 of the SIP Explanation Document, FL DEP indicates that the MATS limit has been incorporated into a permit modification, and Appendix A.4 includes selected pages from that modification. This is inadequate. As indicated in Section 7 of the 2021 Report, FL DEP must subject both units to four-factor analyses for SO_2 and NOx, as there are demonstrated opportunities to upgrade the dry scrubbers and SNCR systems.

6 FL DEP Must Update the Interest Rate Used in its Analyses

FL DEP uses a range of interest rates in its control cost analyses, ranging from 3.25% to 7%. As the Control Cost Manual indicates, if a firm-specific interest rates is not available, then the Bank Prime Interest Rate should be used as an estimate.[11] As of the writing of this report, the current Bank Prime Interest Rate is 8.5%[12]

---

[9] See https://www.epa.gov/sites/production/files/2014-11/documents/pcsnitrogenfertilizer-cd.pdf, page 13.

[10] See Appendix G-2g, page 5 of the June 2021 SIP submittal.

[11] Control Cost Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017. Page 15. Available here: https://www.epa.gov/economic-and-cost-analysis-air-pollutionregulations/cost-reports-and-guidance-air-pollution.

[12] See https://www.federalreserve.gov/releases/h15/.

7 The Update to the WestRock Fernandina Beach Mill No. 7 Power Boiler Four-Factor Analysis is Inadequate

The 2021 Report documented numerous problems with the WestRock Fernandina Beach Four-Factor Analysis, which have not been properly addressed. This section specifically addresses new information FL DEP presents to supplement the four-factor analysis for the No. 7 Power Boiler. In particular FL DEP has assessed whether removing coal as a fuel for the No.7 Power Boiler was cost-effective. This new four-factor analysis is located in Appendix B-1.

7.1 The WestRock Analysis Lacks Documentation

As indicated in Section 8 the 2021 Report, there is a fundamental lack of documentation for a number of items that relate to the WestRock cost analysis. These issues are also present in the current analysis in Appendix B-1 and must be remedied by FL DEP in order for the cost analysis to be acceptable. This includes the Total Capital Investment for New Ultra Low Sulfur Diesel (ULSD) Burners and required infrastructure of $18,750,000. This figure is merely presented with a note that it was estimated by WestRock. It lacks documentation of any kind and is unacceptable. Also, as was discussed in the 2021 Report, a number of cost items are redacted which are typically not claimed as confidential. In the case of truly confidential information, FL DEP must state that it has reviewed those figures and finds them to be acceptable.

7.2 WestRock Has Not Demonstrated it Must Replace the Diesel Burners on the No. 7 Boiler

WestRock claims that in order to cease all coal burning and completely switch to natural gas (for which it has 100% load capability), it must have a backup fuel source that is also capable of 100% load capability. As a first order issue, WestRock must establish what constitutes 100% full load for this boiler. This should be based on any pertinent permit limitations, historical usage data and a reasonable future projection.

As indicated in the 2021 Report, WestRock indicates its ULSD burners are only capable of delivering 46% of full load. That claim must be documented, in relation to the calculation of 100% full load discussed above, as it is fundamental to the cost analysis. WestRock further claims that in order to cease burning coal and have a backup to its current 100% gas burning capability, it must replace its current ULSD burners with new ULSD burners at a cost of $18,750,000. The necessity for a wholesale replacement of its current USLD burners must be documented. WestRock must demonstrate why its current burners cannot be supplemented with additional burners.

In particular, this boiler is now able to use ULSD and/or coal as a backup fuel, and its ability to use ULSD would remain if coal was terminated. Therefore, the potential heat input from the amount of coal it is permitted to burn represents the amount of backup fuel that must be replaced. Furthermore, in its 2021 SIP, FL DEP required reducing the daily coal usage on the No. 7 Boiler to 250 tons/day starting on January 1, 2022, and then to 125 tons/day on April 1, 2024. Therefore, after April 1, 2024, the No. 7 Power Boiler would be capable of supplementing its current ability to burn 100% natural gas, with either ULSD at 46% of claimed full load and/or coal limited to 125 tons/day. That 125 tons/day of coal represents the maximum amount of boiler heat input that would then have to be replaced as a backup fuel source. Presumably, because the initial 250 tons/day limit was itself a reduction and therefore did not represent 100% full load capability, the 125 tons/day reduction represents less than one half of full load capability. FL DEP must therefore justify the need for a full ULSD burner replacement in this context.

In summary, FL DEP must therefore require that WestRock document (1) the full load of the No. 7 Boiler (2) its claim that its current ULSD burners are only capable of supplying 46% of full load, (3) its claim that the current ULSD burners cannot be supplemented with additional burners, (4) how much of full load burning 125 tons/day of coal represents, and (5) all costs.

8 Updates to the Georgia Pacific Foley Mill Four-Factor Analyses are Inadequate

The revised Georgia Pacific (GP) Foley Mill, is present in Appendix B-2d and appears to be copied into the body of the SIP Revisions Document beginning on page 15. Many of the deficiencies identified in the 2021 Report have not been corrected. These include:

- A pervasive lack of documentation.
- Only relying on EPA's RBLC to identify technically feasible controls and not considering other proven instances of technically feasible controls installed on similar sources.
- Particular issues with individual cost items.
- Failure to consider upgrades to existing controls.

Therefore, the 2021 Report remains relevant and FL DEP must consider those comments.

8.1 FL DEP Fails to Consider Potential Common Controls for the Foley Mill Sources

On page 18 of the SIP Revisions Document, FL DEP states that the exhaust flue for the Power Boiler No. 1 shares a common stack with Power Boiler No. 2 and Bark Boilers Nos. 1 and 2. Of these, beside Power Boiler No. 1, Bark Boiler No. 1 is also required to undergo four-factor analyses.[13] However, FL DEP has not considered the installation of SO_2 control devices that could potentially be installed upstream of this common stack and be shared by multiple sources. FL DEP must also investigate whether two or all of the three recovery furnaces can also share an SO_2 control.

FL DEP must require that Foley provide diagrams, schematics and/or other documentation that illustrates the potential opportunity to install SO_2 control devices that could service two or more of the boilers and recovery furnaces, and thoroughly investigate this possibility. A retrofitted SO_2 control device that services multiple sources offers potential cost savings and FL DEP must investigate such an installation.

---

[13] Bark Boiler No. 2 was eliminated from consideration by FL DEP because its SO_2 emissions are less than 5 tons/yr.

8.2 FL DEP Has Not Considered All Potential SO_2 Controls for the Foley Sources

The following summarizes additional controls the FL DEP must require Foley to assess as part of its four-factor analyses.

8.2.1 FL DEP Must Require that Upgrades to the TRS Pre-Scrubber(s) be Assessed

On page 18 of the SIP Revisions Document, FL DEP states that it assumes the SO_2 emissions from the Power Boiler No. 1 are primarily from firing Low-Volume High Concentration Non-Condensable Gas (LVHC-NCG) when used as a backup control device for Bark Boiler No. 1. Just above this, FL DEP indicates the LVHC-NCG are collected and routed to a Total Reduced Sulfur (TRS) pre-scrubber prior to entering the boiler. Via a permit condition, the TRS pre-scrubber is required to remove only 50% of the TRS compounds from the LVHC-NCG. On page 26, FL DEP also indicates a TRS pre-scrubber serves the same function for Bark Boiler No. 1, but it is unclear if this is the same control. In either case, since FL DEP has indicated that it believes the LVHC-NCG is the main source of SO_2, it must require that Foley investigate upgrades to the TRS pre-scrubber(s). Because this would be an upgrade to an existing control it is anticipated to be cost-effective.

8.2.2 FL DEP Must Require that Foley Assess Other Scrubbing Technologies for its Boilers

FL DEP indicates on page 18 that Foley only considered wet scrubbing and Dry Sorbent Injection (DSI) for Power Boiler No. 1. FL DEP indicates on page 26 that Foley considered only adding additional caustic to the wet venturi scrubber for Bark Boiler No. 1. As indicated in Section 6 of the 2021 Report, Foley must consider other wet scrubbing technologies for its boilers.[14] As indicated in Section 6 of the 2021 Report, this must include packed bed wet scrubbing, for which EPA provides a control cost worksheet as part of its Control Cost Manual.[15] FL DEP must also investigate the installation of a wet venturi scrubber with added caustic for Power Boiler No. 1., as it is used as an SO_2 control device on Bark Boiler No. 1.

8.2.3 FL DEP Must Require that Foley Assess Additional Controls for its Recovery Furnaces

Regarding Foley's three recovery furnaces, and as indicated in Section 6 of the 2021 Report, FL DEP should consider EPA Region 4's January 31, 2007, letter to the North Carolina Department of Environment, concerning the BART analysis for the Blue Ridge Canton Paper Mill.[16] This letter discusses a number of process changes applicable to recovery furnaces that could be assessed.

---

[14] See for instance, https://www.energy-xprt.com/articles/modern-gas-cleaning-techniques-for-trs-and-so2-control-in-the-pulp-and-paper-industry-6470.

[15] See the spreadsheet in Section 5 of https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[16] See https://www.in.gov/idem/airquality/files/regional_haze_archive_epa_letter.pdf.

8.3 Foley's Wet Scrubber Cost Analysis for Power Boiler No. 1 is Not Acceptable

On page 19 of the SIP Revisions Document, FL DEP states that Foley used a recent cost estimate developed in 2020 for a wet scrubber to control exhaust from a lime kiln at a facility in Oregon as the basis for calculating the costs for a wet scrubber for Power Boiler No. 1. Foley also states that this cost estimate was adjusted via the "Rule of Six Tenths"; caustic use was based on the molar ratio of sodium hydroxide to SO_2 emitted plus a 10% loss; and electricity requirements, water use, and waste generation costs were based on a "detailed vendor quote for a similar system at a facility in Georgia" which were scaled based on air flow rates. The lack of documentation aside, FL DEP must reject this cobbled-together cost estimate and require that a proper control cost analysis be performed, in conformance with the Control Cost Manual, for the following reasons:

- A power boiler is a much different source than a lime kiln and no reasoning is presented to justify Foley's adoption of this cost analysis for its power boiler.
- EPA's Control Cost Manual's methodologies "are directed toward the "study" estimate with a probable error of 30% percent."[17] All of the various control cost analyses resources included in and accompanying the Control Cost Manual satisfy this basic requirement. However, no information has been provided by Foley or FL DEP to support that its cost estimate meets level of accuracy.
- Additional errors, which were identified in Section 6 of the 2021 Report, are still present.
- As noted above, the Control Cost Manual includes a packed bed scrubber cost analysis, suitable for many industrial applications, that could be easily used by Foley to properly estimate the cost-effectiveness of a scrubber.

8.4 Foley's DSI Cost Analysis for Power Boiler No. 1 is Not Acceptable

On page 21 of the SIP Revisions Document, Foley spends one paragraph discussing its DSI cost analysis for its No. 1 Power Boiler. This presentation appears fundamentally unchanged from the one reviewed in the 2021 Report and thus the deficiencies noted therein remain.

8.5 FL DEP Must Explain a Statement in its Analysis of the Foley Power Boiler No. 1

On page 23 of the SIP Revisions Document, FL DEP makes the following statement with regard to its reasoning for rejecting SO_2 controls for the Foley Power Boiler No. 1: "EPA's Regional Haze Guidance requires states to impose SIP emission limits that reduce the unit's potential to emit to levels that are slightly higher than the historical emission levels." This statement does not seem to appear elsewhere in the SIP, except that it is repeated on page 24 in its summary of its Foley Power Boiler No. 1 analysis. FL DEP does not explain the meaning of this statement. Furthermore, it is unclear from where in EPA's Regional Haze Guidance it was lifted or in what

[17] Control Cost Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017. Page 6. Available here: https://www.epa.gov/economic-and-cost-analysis-air-pollutionregulations/cost-reports-and-guidance-air-pollution.

context it may have been presented. FL DEP must therefore expand on this statement, properly cite it, and explain how it is integrated into its SIP.

8.6 FL DEP's Foley Bark Boiler No. 1 Wet Venturi Scrubber Analysis is Inadequate

On page 26 of its SIP Revisions Document, FL DEP states that it has concluded that the main source of SO_2 from Bark Boiler No. 1, like Power Boiler No. 1, comes from LVHC-NCG. The LVHC-NCG is sent through a spray nozzle-type TRS pre-scrubber prior to going to this boiler. Particulate matter emissions are controlled by a cyclone collector and a wet venturi scrubber. FL DEP states that the current permit conditions for Bark Boiler No. 1 require adding caustic to the wet venturi scrubber only when the TRS pre-scrubber is not operational. FL DEP states that Foley has proposed adding caustic to this wet venturi scrubber at all times, even when the TRS pre-scrubber is running.

On page 27 of the SIP Revisions Document, FL DEP states that with the amount of caustic it assumed, the pH of the fluid would be 8.0 and the SO_2 removal efficiency would be only 51%. FL DEP further states that the 51% control level was determined through "engineering tests that demonstrated that use of the wet venturi scrubber with caustic was a more effective control device for SO_2 than the use of the TRS pre-scrubber." First, as noted above, FL DEP must require that Foley document its 51% control claim. Second, FL DEP must require that Foley investigate upgrades to the TRS pre-scrubber. Third, a pH of 8.0 is within the range of tap water and so constitutes a very weak caustic solution.[18] Therefore, FL DEP must also require that Foley expand its analysis to investigate the use of higher amounts of caustic to the wet venturi scrubber. This is especially evident considering the WestRock Unit 3 wet venturi scrubber with caustic was evaluated at upwards of 98% control, as discussed in Section 9.4 of the 2021 Report. This must include the inclusion of the noted engineering tests, all associated analysis, and complete documentation for all figures and assumptions.

8.7 FL DEP's Foley Recovery Furnace SDA Analysis is Inadequate

On page 31, FL DEP states that Foley considered Spray Dryer Absorbers (SDA), a common and widespread type of dry scrubbing for its recovery furnaces. However, FL DEP further states that to be cost effective, the SDA and dry sorbent injection systems would inject caustic materials upstream of the ESP to neutralize SO_2 and remove the resulting solids formed as well as any excess caustic materials. FL DEP claims that this would contaminate and adversely impact the recovery process such that these systems are not considered feasible for recovery furnaces. This latter statement does not comport with the mechanism and typical installation of SDA systems. FL DEP appears to (1) conflate SDA and DSI systems and (2) believe that an SDA system is constrained to injecting sorbent upstream of an ESP. Both of these views are incorrect. For example, EPA describes SDA systems in its Control Cost Manual.[19] In a typical SDA system,

---

[18] See https://cdn.who.int/media/docs/default-source/wash-documents/wash-chemicals/ph.pdf?sfvrsn=16b10656_4. See page 1: "The pH of most drinking-water lies within the range 6.5–8.5. Natural waters can be of lower pH, as a result of, for example, acid rain or higher pH in limestone areas."

[19] Control Cost Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, Page 1-7. Available here: https://www.epa.gov/economic-and-cost-analysis-air-pollutionregulations/cost-reports-and-guidance-air-pollution.

the sorbent is injected at the top of the SDA vessel and later collected in a bag house. Thus, in a typical SDA system, sorbent is not injected outside of the absorber and it is not constrained to be injected upstream of an existing ESP. In addition, there are other dry scrubbing technologies, including a Circulating Dry Scrubber (CDS), also discussed in the aforementioned Control Cost Manual. FL DEP must therefore correct its analysis to properly include various types of dry scrubbing.

8.8 FL DEP's Foley Recovery Furnace Wet Scrubber Analysis is Inadequate

Beginning on page 33 of the SIP Revisions Document, FL DEP presents its cost analyses for installing wet scrubbers on Foley recovery Furnaces Nos. 2, 3, and 4. The following comments address these analyses:

- As indicated above, FL DEP must investigate whether a common wet scrubber can be configured to service multiple recovery furnaces and/or boilers, which would likely improve cost-effectiveness (lower $/ton).

- FL DEP assumes Black Liquor Solids (BLS) values for each furnace. These are key inputs to the cost analyses and must be documented and correlated to the uncontrolled SO_2 values assumed for each furnace. In all cases, these figures are listed as "permitted capacity." First, FL DEP must explain why previous values for BLS, used in the October 22, 2020 analysis in Appendix B-2a were higher. Second, it is assumed that the BLS rate was used to size the scrubber and calculate some of the operating and maintenance costs. As such, because the SO_2 comes from the BLS, it is not reasonable to assume the maximum value of BLS (the permitted capacity) while assuming some average for the uncontrolled SO_2 emissions. In other words, this introduces an apples-to-oranges mismatch that must be resolved.

- Foley bases these costs on a quote it obtained from a vendor. Assuming that is confidential information, FL DEP must state that it reviewed that quote and found it to be reasonable and without unnecessary cost items. If it is not confidential, it must be included in the SIP.

- FL DEP must eliminate escalation from these costs, which is significant at 8% of the sum of the equipment, installation, and balance of plant costs. As used here, escalation is Allowance for Funds Used During Construction (AFUDC), which is disallowed under the overnight methodology used in the Control Cost Manual.[20]

- The electrical usage in these costs is noted to be "ratioed based on AFPA values. FL DEP must provide these calculations.

[20] Control Cost Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017. Page 11. Available here: https://www.epa.gov/economic-and-cost-analysis-air-pollutionregulations/cost-reports-and-guidance-air-pollution.

- FL DEP assumes a wet scrubbing efficiency of only 90%, which is low. Modern wet scrubbers are easily able to achieve efficiencies of at least 98%.[21] Thus, FL DEP must revise this estimate to assume at least 98% control.

- As indicated earlier in this and the 2021 Report, FL DEP must assess packed bed wet scrubbing, for which EPA provides a control cost worksheet as part of its Control Cost Manual.[22]

9 Updates to the WestRock Panama City Mill Four-Factor Analyses Are Inadequate

The four-factor Analysis for the Panama City Mill present in Appendix B is dated October 2020 and so does not appear to have been updated since reviewed in 2021 Report. It appears that FL DEP's update to it prior analysis consists of relatively minor changes in sections of the text.

Many of the deficiencies identified in the 2021 Report have not been corrected. These include:

- A pervasive lack of documentation.
- Improper cost items.
- Failure to consider proven control technologies.
- Failure to consider upgrades to existing controls.
- Particular issues with individual cost items.
- Lack of due diligence in investigating fuel switching.

Therefore, the 2021 Report remains relevant and FL DEP must consider those comments.

Most of the additional text consists of undocumented statements. For example, FL DEP states on page 44 of the SIP Revision Document that it noted that some parts of Westrock's analysis were not justified adequately or were inconsistent with EPA's Cost Control Manual. However, it states that even with the corrections to certain values, it determined that replacing No. 6 fuel oil with ULSD, increasing caustic to the wet scrubber, or installing SDA are not cost effective. FL DEP must provide proper documentation to support these claims, including revised control cost analyses.

---

[21] Control Cost Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, Page 1-3 through 1-5. Available here: https://www.epa.gov/economic-and-cost-analysis-air-pollutionregulations/cost-reports-and-guidance-air-pollution.
[22] See the spreadsheet in Section 5 of https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Exhibit 2

BEFORE THE AIR QUALITY CONTROL COMMISSION
STATE OF COLORADO

IN THE MATTER OF PROPOSED REVISIONS TO REGULATION NUMBER 23
NOVEMBER 17 to 19, 2021 HEARING

PREHEARING STATEMENT OF THE COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT, AIR POLLUTION CONTROL DIVISION

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

[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.

---

[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. <u>Proposed EGU Closure Dates</u>

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. <u>Cost Considerations in 4-factor Analyses</u>

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

---

[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*

Josh Korth
Technical Support and SIP Unit Supervisor
Colorado Department of Public Health and Environment
Air Pollution Control Division
4300 Cherry Creek Drive South
Denver, Colorado 80246
Email: joshua.korth@state.co.us

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.

Air Quality Control Commission
jeremy.neustifter@state.co.us
theresa.martin@state.co.us
tom.roan@coag.gov
dan.graeve@coag.gov

Air Pollution Control Division
garrison.kaufman@state.co.us
dena.wojtach@state.co.us
joshua.korth@state.co.us
jaclyn.calicchio@coag.gov
john.watson@coag.gov

City and County of Denver
william.obermann@denvergov.org
lindsay.carder@denvergov.org

City of Colorado Springs & Colorado Spring Utilities
mari.deminski@coloradosprings.gov
jrosen@wsmtlaw.com
jsanderson@wsmtlaw.com

Colorado Communities for Climate Action
jsmith@cc4ca.org
easley@rockymountainclimate.org
ccopeland@bouldercounty.org
ctomb@bouldercounty.org
skeane@kaplankirsch.com
scaravello@kaplankirsch.com
wmumby@kaplankirsch.com

Colorado Energy Office
keith.m.hay@state.co.us
david.banas@coag.gov
barbara.dory@coag.gov

GCC Pueblo
adam@devoe-law.com

Holcim (US) Inc.
john.goetz@lafargeholcim.com
darlene.bray@lafargeholcim.com
paul.desantis@lafargeholcim.com
john.jacus@dgslaw.com

Molson Coors USA LLC
jrosen@wsmtlaw.com
jsanderson@wsmtlaw.com

National Park Service
lisa_devore@nps.gov
kirsten_king@nps.gov
melanie_peters@nps.gov

National Parks Conservation Association & Sierra Club
skodish@npca.org
tcoppola@npca.org
matt.gerhart@sierraclub.org
cmiller@earthjustice.org
mhiatt@earthjustice.org

Platte River Power Authority
leonards@prpa.org
hammittj@prpa.org
woodc@prpa.org
jrosen@wsmtlaw.com
jsanderson@wsmtlaw.com

Public Service Company of Colorado dba Xcel Energy
jon.h.bloomberg@xcelenergy.com
chad.campbell@xcelenergy.com

Suncor Energy (USA) Inc.
mkorenblat@suncor.com
jrock@suncor.com
jbiever@williamsweese.com
cromo@williamsweese.com
clim@williamsweese.com

Tri-State Generation & Transmission Association, Inc.
aberger@tristategt.org
dlempke@tristategt.org
jrosen@wsmtlaw.com
jsanderson@wsmtlaw.com

United States Forest Service – Rocky Mountain Region
steven.lohr@usda.gov
jeff.sorkin@usda.gov

Weld County BOCC
bbarker@co.weld.co.us

/s/ John Watson
John Watson

Exhibit 3

NEVADA REGIONAL HAZE STATE IMPLEMENTATION PLAN FOR THE SECOND PLANNING PERIOD

A Plan for Implementing
Section 308 (40 CFR § 51.308)
of the Regional Haze Rule

Second Implementation Period (2018-2028)

NEVADA DIVISION OF
ENVIRONMENTAL
PROTECTION

Nevada Department of
CONSERVATION &
NATURAL RESOURCES

State of Nevada
Division of Environmental Protection
901 South Stewart Street, Suite 4001
Carson City, Nevada 89701

August 2022

EXECUTIVE SUMMARY

The federal Regional Haze Rule (RHR) requires Nevada to address statewide emissions of visibility impairing pollutants that contribute to regional haze in each mandatory Class I area (CIA) located in Nevada and each mandatory CIA located in nearby or neighboring states. Jarbidge Wilderness Area (WA) is the only mandatory CIA located in Nevada. Under the RHR, Nevada is required to submit a State Implementation Plan (SIP) addressing the specific elements required by the RHR. This document serves as the State of Nevada's SIP submittal provided to the U.S. Environmental Protection Agency (EPA) Region 9 to satisfy the rule requirements outlined in 40 CFR Part 51, Subpart P, Section 51.308. This submittal is a revision to the regional haze SIP that Nevada submitted for the initial implementation period of the rule and amends the first round SIP when adopted.

The RHR covers a long period, broken into several planning phases to ultimately meet the national goal of returning visibility at all designated CIAs to natural conditions. The approach taken in preparing this RH SIP is to address the second planning period (2018 through 2028). Assuming natural visibility conditions are achieved by 2064, this plan meets the requirements of improving visibility for the most impaired days and ensuring no degradation in visibility for the clearest days for the period ending in 2028, the second planning period in the federal rule. Nevada's RH SIP has been prepared by the Nevada Division of Environmental Protection (NDEP) and contains strategies and elements related to each requirement of the federal rule. The SIP is based on data that existed as of December 2021.

Calculations of Baseline, Current, and Natural Visibility Conditions; Progress to Date; and the Uniform Rate of Progress

The RHR at 40 CFR 51.308(f)(1) requires the state to calculate baseline, current, and natural visibility conditions, which in turn are used to calculate progress to date and the uniform rate of progress (URP) per year necessary to achieve natural conditions by 2064. Although achieving natural visibility conditions by 2064 is not required by the RHR, or part of the national visibility goal, it is used by states as a reference point to develop the URP metric and measure progress between each decadal implementation period. To develop the URP, or glidepath, states must determine baseline visibility conditions for the period 2000 through 2004, current visibility conditions for the period 2014-2018, and natural background visibility conditions to be achieved by 2064. Achievement of natural visibility conditions by 2064 is only measured among the 20 percent "most-impaired" days (excluding episodic events like wildfire) of each year, while the 20 percent "clearest" days must not degrade beyond the 20 percent clearest days of the baseline visibility conditions measured during the first round.

NDEP has calculated the baseline, current, and natural visibility conditions record at Jarbidge WA during both the most impaired days and clearest days. During the most impaired days, visibility conditions at Jarbidge WA have shown a steady improvement in visibility since the baseline conditions were calculated during the initial implementation period and confirms that visibility conditions at Jarbidge WA are on track to achieve natural conditions by 2064. During the clearest days, NDEP has confirmed that current visibility conditions have not degraded since the previous round.

An analysis of pollutant species contributing to visibility impairment at Jarbidge WA, for both the most impaired and clearest days, indicates that ammonium sulfate (originating from anthropogenic sulfur dioxide emissions) and organic mass carbon (typically originating from wildfire emissions) are the top two pollutants of concern. Beyond these two pollutants, coarse mass (typically originating from windblown dust events and fugitive dust) is the third pollutant of concern. Ammonium nitrate (originating from anthropogenic oxides of nitrogen emissions) becomes a more significant visibility impairing pollutant at Jarbidge WA during the winter months. This data suggests that visibility at Jarbidge WA is significantly impacted by both anthropogenic and natural sources. High levels of organic mass carbon indicate that wildfire emissions still interfere with Nevada's ability to track visibility progress, despite the efforts of the new "most-impaired days" metric that aims to remove wildfire impacts.

Long-term Strategy for Regional Haze

The RHR at 40 CFR 51.308(f)(2) requires the state to submit a long-term strategy that addresses regional haze visibility impairment at all mandatory Class I areas that may be impacted by emissions from the state. The strategy must include enforceable emissions limitations, compliance schedules and other measures as necessary to achieve the state's reasonable progress goals. As part of the technical basis for the long-term strategy, the state must identify its baseline emissions inventory and all anthropogenic sources of visibility impairment. This SIP covers long-term strategies for visibility improvement between current conditions and visibility conditions projected for 2028.

An emission inventory, organized by sector and pollutant species, is provided for the current and 2028 projection conditions (representing the outcome of this SIP's efforts to improve visibility). In NDEP's projection of 2028 conditions, statewide emissions of visibility impairing pollutants are tremendously dominated by volatile organic compounds from natural biogenic emissions followed by coarse particulate matter from fugitive dust emissions. Statewide sulfur dioxide and nitrogen of oxides emissions, the anthropogenic pollutants considered for further reductions by NDEP, are miniscule compared to other pollutants and account for a small percentage of total statewide visibility impairing pollutants.

Visibility and source apportionment modeling show that Nevada's reduction in visibility impairing pollutants during the second implementation period will aid Jarbidge WA, and other out-of-state CIAs, in achieving the necessary visibility improvements toward natural conditions. Visibility projections for Jarbidge WA in 2028 show that enough visibility improvement will be achieved, as a result of the emission reductions of this round, to remain on track toward natural visibility conditions by 2064. Because of this, no further emission reductions are needed for the second implementation period.

To achieve additional emission reductions in Nevada as part of the SIP's Long-Term Strategy, NDEP identified eight point sources that reasonably emit pollutants impacting visibility impairment at Jarbidge WA. NDEP determined additional emission reduction measures necessary at each facility to achieve reasonable progress for the second implementation period by considering the four statutory factors: cost of compliance, time necessary for compliance, energy and non-air quality impacts, and the remaining useful life of the source. NDEP concluded that the closure of three electrical generating units, implementation of add-on controls at a lime production plant, new emission limits for existing controls at a facility, and the continued use of several existing controls are all necessary to achieve reasonable progress for this round.

Monitoring Strategy

The RHR at 40 CFR 51.308(f)(6) requires the state to develop a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment that is representative of all mandatory Class I areas within Nevada.

Visibility conditions in mandatory Class I areas throughout the United States are presently measured by the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring network, which is operated and maintained through a formal cooperative relationship between USEPA and Federal Land Manager (FLM) agencies. Nevada commits to continue using the IMPROVE monitoring data and to update Nevada's emissions inventory periodically, as required by the RHR. The inventory updates will be used for state tracking of emission changes and trends, to provide input into the evaluation of whether reasonable progress goals will continue to be achieved at Jarbidge WA and for other regional analyses.

State and Federal Land Manager Coordination

The RHR at 40 CFR 51.308(f)(2)(ii) requires states to coordinate with other states during the development of reasonable progress goals and emission management strategies. Nevada has met these requirements through participation in the Western Regional Air Partnership (WRAP) and commits to continue to coordinate via the WRAP for future implementation periods. In the WRAP process, Nevada participated in various forums and workgroups to help develop a coordinated emissions inventories and analyses of the impacts that sources have on regional haze in the west. In more direct discussions with neighboring states, NDEP has confirmed that no out-of-state Class I areas are reliant on further emission controls in Nevada beyond what is proposed in this SIP in order to achieve reasonable progress by the end of the second planning period.

40 CFR 51.308(i) further requires states to coordinate with FLMs in developing the RH SIP. States must provide a contact to whom FLMs can submit recommendations on the implementation of the RHR; provide FLMs an opportunity for consultation at least 60 days prior to holding any public hearing on the SIP; provide a public record of how the state addressed any FLM comments; and provide procedures for continuing consultation with FLMs on the implementation of the state's RH SIP. A draft of Nevada's RH SIP was provided to the FLMs with a 60-day comment period prior to the public hearing on the SIP. Documented in this SIP, NDEP has addressed comments provided by the FLMs before the commencement of public comment. NDEP commits to continuing these consultations with the FLMs in future planning periods.

Summary Figures and Tables

Figure ES-1 illustrates the observed visibility conditions at Jarbidge Wilderness Area, sorted by visibility impairing pollutants in ambient air. During the baseline years, from 2000 through 2004, the most impaired days are largely impacted by ammonium sulfate (32%), organic mass carbon (28%), and coarse mass (17%). During the same period for the clearest days, ammonium sulfate continues to dominate (42%), followed by organic mass carbon (27%). During the current period, from 2014 through 2018, the same trend continues with the most impaired days largely impacted by ammonium sulfate (29%), organic mass carbon (29%), and coarse mass (22%). The clearest days are impacted by the same three pollutant species: ammonium sulfate (42%), organic mass carbon (27%), and coarse mass (13%). Note that during the clearest days for both periods, which typically occur during the winter months, ammonium nitrate extinction contribution jumps up (~10%).

Table ES-1 outlines the incremental change in visibility conditions at Jarbidge WA across all major time periods (baseline, current, 2028 projection, and 2064 goal of natural conditions) and indicates a consistent downward trend in visibility impairment, or regional haze, during the most impaired days that is on track to achieve natural conditions by 2064. A similar downward trend is observed during the clearest days toward estimated natural conditions at Jarbidge WA, however, the RHR only requires that visibility conditions not degrade beyond the baseline conditions. Table ES-1 shows that the projected visibility condition during the clearest days in 2028 (1.72 dv) does no degrade beyond the baseline condition (2.56 dv).

Figure ES-2 graphically displays the visibility conditions outlined in Table ES-1 and compares these values to the uniform rate of progress (solid green line), clearest days baseline (solid brown line) and observed annual visibility conditions for both the most impaired days (dashed light blue line) and clearest days (dashed orange line). The figure shows that in order to achieve that national goal of natural visibility conditions of 7.39 dv by 2064, projected visibility conditions in 2028 at Jarbidge WA must be at least 8.20 dv, or below. NDEP predicts that visibility conditions during the most impaired days at Jarbidge WA will be 7.76 dv in 2028. NDEP also predicts that visibility conditions during the clearest days will be 1.72 dv in 2028, well below the goal of 2.56 dv.

Table ES-2 outlines the total emissions reductions in tons per year expected as a result of Nevada's Long-Term Strategy for the second implementation period. These reductions are achieved from new control measures identified as necessary to achieve reasonable progress after consideration of the four statutory factors. As seen in the table, roughly 2,300 tons per year of NO_x and SO_2 emissions are expected, or a total of 4,600 tons per year.

Figure ES-1: Baseline and Current Visibility Conditions for the Most Impaired and Clearest Days by Pollutant Species

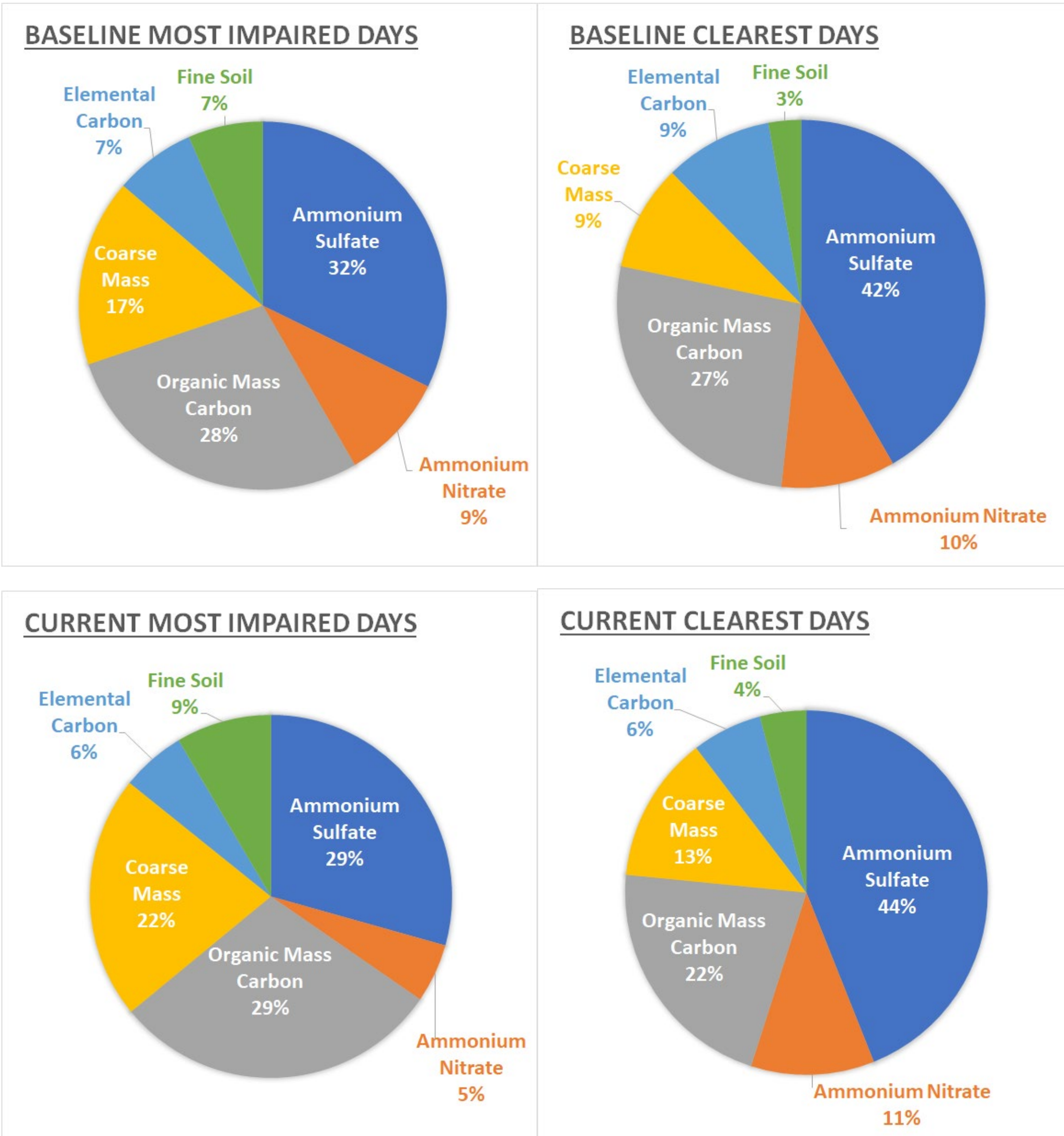


Table ES-1: Visibility Progress at Jarbidge Wilderness Area Toward National Goal of Natural Visibility Conditions by 2064 (deciviews)

Period	Years	Most Impaired Days Average	Clearest Days Average
Baseline Condition	2000-2004	8.73	2.56
Current Condition	2014-2018	7.97	1.84
Projected Condition	2028	7.76	1.72
Natural Condition Goal	2064	7.39	1.14

Figure ES-2: Uniform Rate of Progress for Jarbidge Wilderness Area

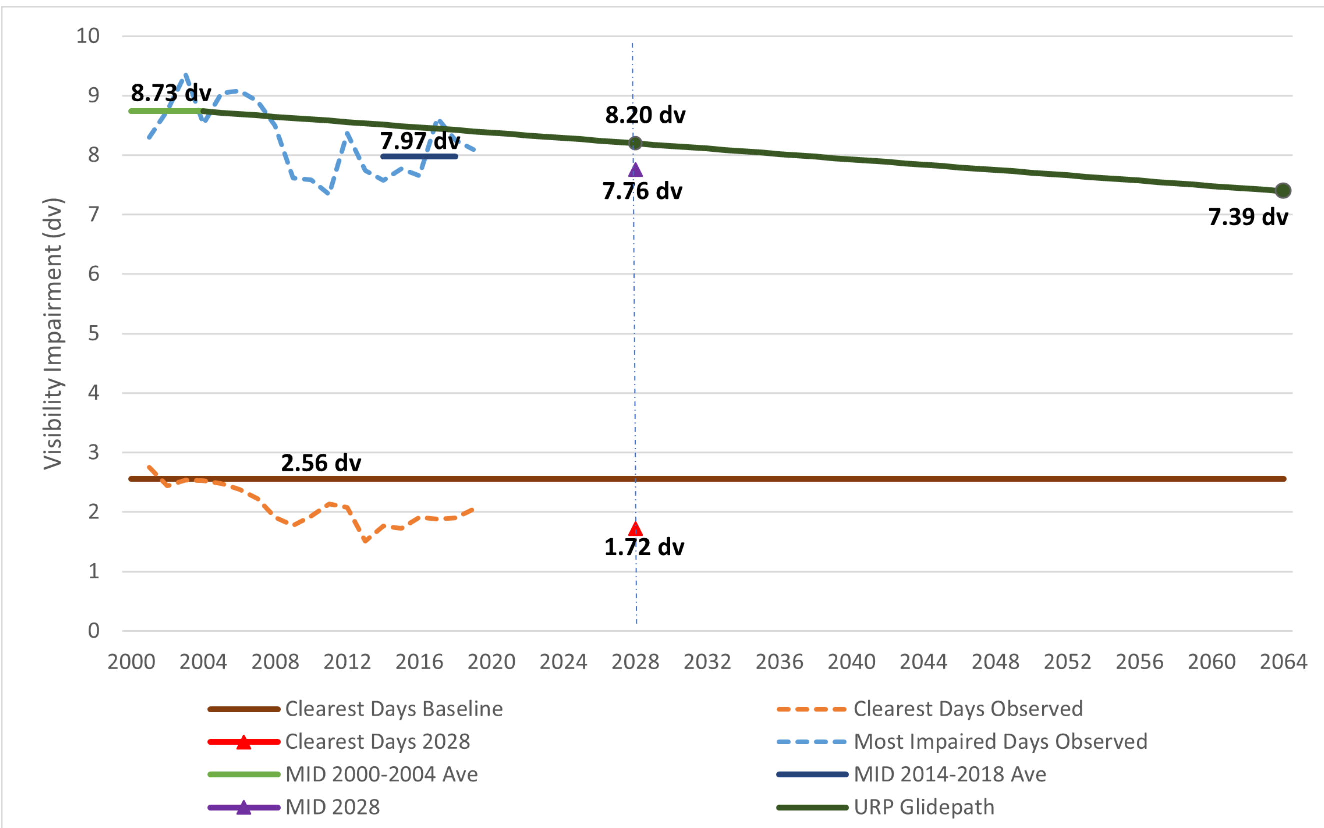


Table ES-2: Long-Term Strategy Emissions Reductions

NO_x	SO_2	PM_{10}	Total
2,239	2,313	60	4,612

CONTENTS

CONTENTS - Continued

CONTENTS - Continued

CONTENTS - Continued

Acronyms, Abbreviations and Terms

2014v2	2014 Emissions Inventory Version 2
2028OTBa2	2028 On-the-Books/On-the-Way Emission Inventory Version 2
2028PAC2	2028 Potential Additional Controls Emission Inventory Version 2
AMET	EPA Atmospheric Model Evaluation tool
ARP	Acid Rain Program
BART	Best Available Retrofit Technology
BACT	Best Available Control Technology
BLM	Bureau of Land Management
CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model with Extensions
CARB	California Air Resources Board
CASTNET	Clean Air Status and Trends monitoring network
CCDES	Clark County Department of Environment and Sustainability
CD	Consent Decree
CIA	Class I Area
CENWRAP	Central West Regional Air Partnership
CFR	Code of Federal Regulations
CM	Coarse Matter
CSN	Chemical Speciation Network
CTI	Cleaner Trucks Initiative
DERA	Diesel Emissions Reduction Act
EGU	Electrical Generating Unit
EIMP	Emission Inventories and Modeling Protocol Work Group
EJ	Environmental Justice
EWRT	Extinction-Weighted Residence Time
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FIP	Federal Implementation Plan
FLM	Federal Land Manager
FSWG	Fire and Smoke Work Group
FWS	Fish & Wildlife Service
GEOS-Chem	Goddard Earth Observing System global chemical model
GHG	Greenhouse Gas
HI	Haze Index
HMS	Hazard Mapping System
IMPROVE	Interagency Monitoring of Protected Visual Environments
IWDW	Intermountain West Data Warehouse
JARB1	Jarbidge Wilderness Area IMPROVE Monitor
LNB	Low-NO_x Burner(s)
LEV	Low-Emission Vehicle
LTS	Long-Term Strategy
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
Mm^{-1}	Inverse Megameter
MOU	Memorandum of Understanding
MOVES	Motor Vehicle Emission Simulator
MW	Megawatts

NAAQS	National Ambient Air Quality Standards
NAC	Nevada Administrative Code
NDEP	Nevada Division of Environmental Protection
NEI	National Emission Inventory
NEIv2	National Emission Inventory version 2
NG	Natural Gas
NPS	National Park Service
NRS	Nevada Revised Statutes
NSR	New Source Review
NTEC	National Tribal Environmental Council
OFA	Over-Fired Air
OGWG	Oil & Gas Work Group
PNG	Pipeline Natural Gas
PSAT	Particulate Source Apportionment Technology
PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RAVI	Reasonable Attributable Visibility Impairment
RepBase2	Representative Baseline Emission Inventory Version 2
RH	Regional Haze
RHPWG	Regional Haze Planning Work Group
RHR	Regional Haze Rule
RMC	Regional Modeling Center
RPG	Reasonable Progress Goal(s)
RPO	Regional Planning Organizations
RPS	Renewable Portfolio Standard
RRF	Relative Response Factor
SCR	Selective Catalytic Reduction
SEC	State Environmental Commission
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kerner Emissions
SNCR	Selective Non-Catalytic Reduction
TSS	Technical Support System
USEPA	United States Environmental Protection Agency
USFS	United States Forest Service
URP	Uniform Rate of Progress
VIEWS	Visibility Information Exchange Web System
WA	Wilderness Area
WAQS	Western Air Quality Study
WEP	Weighted Emissions Potential
WESTAR	Western States Air Resources Council
WGA	Western Governors Association
WPS	WRF Preprocessing System
WRAP	Western Regional Air Partnership
WRF	Weather Research and Forecasting
ZEV	Zero-Emission Vehicle

Chemicals and Chemical Compounds

CO	Carbon Monoxide
EC	Elemental Carbon
HNO_3	Nitric Acid
NH_3	Ammonia
NH_4	Ammonium
NH_4NO_3	Ammonium Nitrate
$(NH_4)_2SO_4$	Ammonium Sulfate
NMHC	Non-Methane Hydrocarbons
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrate
NO_x	Oxides of Nitrogen
OC	Organic Carbon
OMC	Organic Matter Carbon
$PM_{2.5}$	Fine Particulate Matter (2.5 micrometers and smaller in diameter)
PM_{10}	Coarse Particulate Matter (10 micrometers and smaller in diameter)
POA	Primary Organic Aerosols
SO_2	Sulfur Dioxide
SO_4	Sulfate
VOC	Volatile Organic Compounds

List of Tables

CHAPTER ONE

CHAPTER TWO

CHAPTER THREE

CHAPTER FOUR

CHAPTER FIVE

List of Figures

CHAPTER ONE

CHAPTER TWO

List of Figures - Continued

CHAPTER THREE

CHAPTER FOUR

CHAPTER FIVE

CHAPTER SIX

List of Figures - Continued

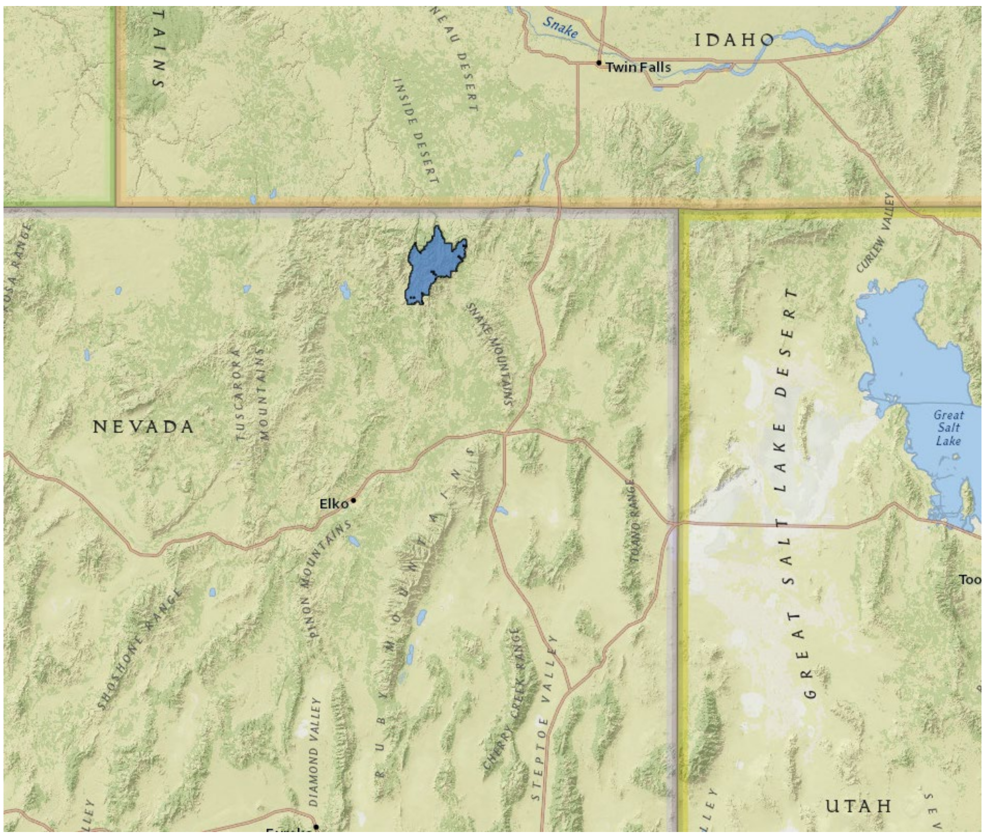
Chapter One – Overview

1.1 NEVADA'S CLASS I AREA – JARBIDGE WILDERNESS AREA

Nevada has one mandatory Class I Area, the 113,167-acre Jarbidge Wilderness Area (Jarbidge WA), located within the Humboldt National Forest in the northeastern portion of Nevada, as shown on Figure 1-1.

FIGURE 1-1

JARBIDGE WILDERNESS AREA LOCATION



Jarbidge WA lies near the Idaho border just north of the physical geographic boundary separating the Columbia Plateau region, including the Snake River Plain, and the Great Basin region to the south. It consists of the headwaters basin of the Jarbidge River East Fork that flows north from the center of the wilderness area, and the headwaters basin of Marys River that flows south from the center of the wilderness area, part of the Columbia River/Great Basin hydrographic divide. The terrain encompassed by the wilderness area consists of deep canyons with steep slopes. The Jarbidge River Canyon, which comprises the upper main headwaters of the Jarbidge River proper, is oriented south to north, with its mouth several miles to the north where it drains into the Bruneau River.

The area illustrates Nevada's typical basin and range topography with elevations ranging from 2,100 m (6,900 ft) where the Jarbidge River East Fork exits the wilderness into Idaho's Snake

River Plains to eight peaks over 3,000 m (~10,000 ft) high along the Jarbidge Mountain crest, which includes the highest peak, Marys River Peak at 3,170 m (10,398 ft).

Unlike the rest of the state, Jarbidge WA is unusually wet, with an average of 7-8 ft of total snowfall and 1-2 ft of total precipitation. The varied terrain is cut by deep canyons with steep slopes and supports a range of vegetation zones from sagebrush flats to glaciated alpine basins. During the warmer months, these scenic vistas and their 150 miles of hiking trails are a major tourist attraction.

1.2 VISIBILITY IMPAIRMENT

Regional haze is pollution from disparate sources that impairs visibility over a large region, including national parks, forests and wilderness areas (156 of which are termed mandatory federal Class I areas). Regional haze is caused by sources and activities emitting fine particles and their precursors. Those emissions are often transported over large regions. Particles affect visibility through the scattering and absorption of light, and fine particles – particles similar in size to the wavelength of light – are most efficient, per unit of mass, at reducing visibility. Fine particles may either be emitted directly or formed from emissions of precursors, the most important of which are sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Reducing fine particles in the atmosphere is generally considered to be an effective method of reducing regional haze, and thus improving visibility. Fine particles also adversely impact human health, especially respiratory and cardiovascular systems.

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources include windblown dust and smoke from wildfires. Anthropogenic sources include motor vehicles, electric utility and industrial fuel burning, and manufacturing operations. Higher concentrations of pollutants result in more absorption and scattering of light, which reduce the clarity and color of a scene. Some types of particles, such as sulfates, are more effective at scattering light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye, and the object may be a single viewing target or scene.

In the 156 mandatory Class I areas across the country, visual range has been substantially reduced by air pollution. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Much of the visibility impairment in the West can be attributed to natural emissions of smoke and dust with significant contributions resulting from international emissions from beyond the boundaries of the United States, including Canada and Mexico.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are carried many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to very small particles in the air has been linked with increased respiratory illness, decreased lung function and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers and streams unsuitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings, or other natural and manmade structures.

1.3 THE WESTERN REGIONAL AIR PARTNERSHIP AND NEVADA

USEPA initially funded five Regional Planning Organizations throughout the country to coordinate regional haze rule-related activities between states in each region. Nevada belongs to the Western Regional Air Partnership (WRAP), the consensus organization of western states, tribes, and federal agencies, which oversees analyses of monitoring data and preparation of technical reports regarding regional haze in the western United States.

The WRAP was formed in September 1997 as the successor organization to the Grand Canyon Visibility Transport Commission. It is administered jointly by the Western Governors Association (WGA) and the National Tribal Environmental Council (NTEC). The mission of the WRAP is to identify regional or common air management issues and to develop and implement strategies to address these issues. The WRAP is a partnership of states and tribes as well as federal agencies and was designated by USEPA to assist western states in the development of regional haze plans. It provides a coordination mechanism with regard to science and technology support for policy and programmatic uses in the western United States.

WRAP member states include Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Federal participants are the Department of the Interior (National Park Service and Fish & Wildlife Service,) the Department of Agriculture (Forest Service) and USEPA.

Work by WRAP committees, forums and workgroups is accomplished by the staff time contributed by state, tribal, Federal Land Manager (FLM), EPA and environmental, industry and public representatives, with the support of WRAP staffing through WGA and NTEC. WRAP work is also handled through contracts to environmental consulting firms, to analyze air pollution data collected by states and tribes in their regulatory programs as well as to prepare data and analyses for natural and/or uncontrollable air pollution sources.

The WRAP established stakeholder-based technical and policy oversight committees to assist in managing the development of regional haze work products. Working groups and forums were established to develop technical tools and work products the states and tribes needed to develop their implementation plans. Much of the WRAP's effort focused on regional technical analysis, which is the basis for developing strategies to meet the Regional Haze Rule (RHR) requirement to demonstrate reasonable progress towards natural visibility conditions in Class I areas. This includes the compilation of emission inventories, air quality modeling and ambient monitoring and data analysis.

The WRAP has developed a regionally-consistent and comparable body of technical data and analysis tools that has been invaluable in addressing regional haze in the west. These data and tools are provided for use and evaluation through a transparent and open network of interrelated data support web systems and a technical decision support system:

WRAP Technical Data Support Centers

- Intermountain West Data Warehouse (https://views.cira.colostate.edu/iwdw/): IWDW provides easy online access to monitored air quality data, gridded modeling products, emissions data, and an integrated suite of tools to help assess air quality on Federal lands.

WRAP Technical Decision Support System

- Technical Support System (http://views.cira.colostate.edu/tssv2/): TSS integrates a number of different data support resources under one web-based decision support umbrella for regional haze planning and implementation.

In addition to these technical tools and work products, the WRAP has provided a forum for coordination and consultation with other states, tribes and FLMs. The major amount of interstate consultation in the development of this SIP was through the Regional Haze Planning Work Group (RHPWG) of the WRAP. Nevada participated in the RHPWG, which took the products of the WRAP technical analysis and consultation process and developed a process for establishing reasonable progress goals in the western Class I areas. Chapter Nine of this document discusses the process that Nevada participated in to address the consultation requirements with FLMs, tribes and other WRAP states during the development of this plan and Nevada's commitments for future consultation.

1.4 TECHNICAL SUPPORT BACKGROUND

1.4.1 Regional Haze Monitoring Network

In response to the 1977 Clean Air Act Amendments, the IMPROVE program was established in 1985 to aid the creation of federal and state implementation plans for the protection of visibility in Class I areas. Air monitoring devices at these locations are operated and maintained through a formal cooperative relationship between the USEPA and the National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management and U.S. Forest Service, collectively called the FLMs. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators, the Association of Local Air Pollution Control Officials, Western States Air Resources Council, Mid-Atlantic Regional Air Management Association and Northeast States for Coordinated Air Use Management.

The IMPROVE program implemented an extensive long-term monitoring program to establish the current visibility conditions, track changes in visibility and determine causal mechanism for the visibility impairment in the national parks and wilderness areas. The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups and air quality regulators to better understand and protect the visual air quality resource in Class I areas. IMPROVE documents the visual air quality in wilderness areas and national parks throughout the United States.

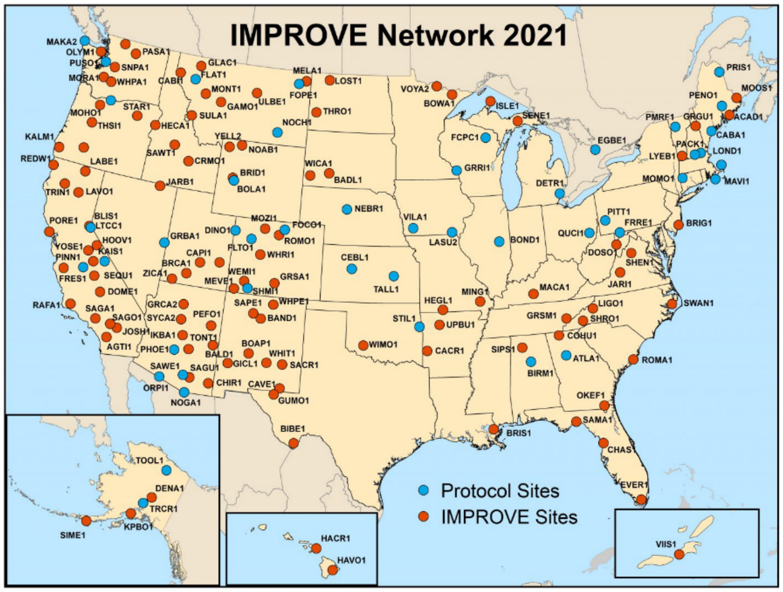
1.4.1.1 Overview of the IMPROVE Monitoring Network

The IMPROVE network focuses on rural areas in the western Unites States. Other visibility and aerosol monitoring networks, such as that of the National Weather Service Airport Visibility

Data, may focus on different air sheds and have different data collection objectives. In 1988, IMPROVE began with 20 monitoring sites. After publication of the regional haze rule in 1999, the first step in the implementation process was the upgrade and expansion of the IMPROVE network to 110 sites nationally. Figure 1-2 shows the IMPROVE monitoring network throughout the United States.

FIGURE 1-2

<u>MAP OF IMPROVE MONITORING NETWORK IN THE UNITED STATES</u>

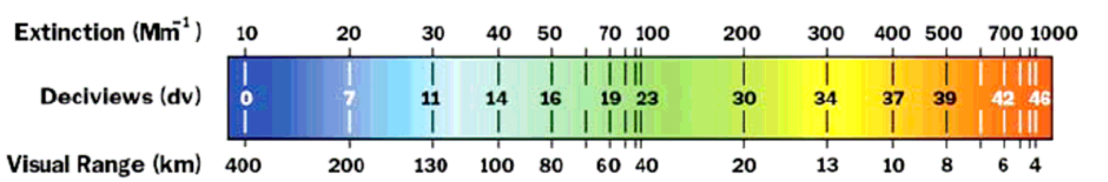


The IMPROVE network consists of aerosol and optical samplers. Every IMPROVE site deploys an aerosol sampler to measure speciated fine aerosols and coarse mass. Select sites also deploy a transmissometer and nephelometers to measure light extinction and scattering respectively, as well as automatic camera systems to visually measure the scene. Particulate concentration data are obtained every 24 hours and converted into reconstructed light extinction through a complex calculation using the IMPROVE algorithm which may be viewed at https://vista.cira.colostate.edu/Improve/the-improve-algorithm/. Light extinction, the impairment of visibility, occurs due to particles and gases that reflect and absorb light.

Reconstructed light extinction (denoted as b_{ext}) is expressed in units of inverse megameters (1/Mm or Mm^{-1}). The RHR requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in the deciview unit (40 CFR 51.308(d)(2)). The relationship between light extinction in Mm^{-1}, Haze Index in dv and visual range in km is indicated by the scale in Figure 1-3.

FIGURE 1-3

LIGHT EXTINCTION-HAZE INDEX-VISUAL RANGE SCALE



Generally, a one dv change in the Haze Index is likely humanly perceptible under ideal conditions regardless of background visibility conditions. More information regarding tracking visibility conditions is found in USEPA's *Guidance for Tracking Progress Under the Regional Haze Rule* at: https://www.epa.gov/visibility/visibility-guidance-documents.

The IMPROVE data undergo extensive quality assurance and control procedures and analyses by its contractors and the National Park Service before it is released. The aerosol and optical data are made publicly available approximately nine months after collection. In addition, seasonal and annual data reports, special study data reports, technical publications and other data and analysis reports are prepared. IMPROVE program resources are available at: http://vista.cira.colostate.edu/Improve.

1.4.1.2 IMPROVE Monitor JARB1

Two operating IMPROVE monitoring sites are located in Nevada, one at Great Basin National Park and the other at the Jarbidge WA. The Walker River Paiute Tribe, a third monitoring site in Nevada, operated from June 2003 to November 2005. The IMPROVE monitor representing the air quality at the Jarbidge WA is identified as JARB1.

JARB1 was among the first 20 IMPROVE sites to start operation in 1988 and is sponsored by the U. S. Forest Service. Generally, JARB1 is expected to be representative of aerosol characteristics in the Jarbidge WA especially when the atmosphere is well mixed and regionally homogeneous. However, the site is at a low elevation in the Jarbidge River Canyon that is separate from the Jarbidge WA and upper East Fork of the Jarbidge River. Consequently, the monitoring site may at times be isolated from wilderness locations and potentially impacted by different local emission sources. Figure 1-2 shows the location of the JARB1 monitoring site by a red dot located along the northern border of Nevada.

As does every IMPROVE site, JARB1 deploys an aerosol sampler to measure speciated aerosols and coarse mass. Along with other selected sites, JARB1 also has an automatic camera system to obtain a visual record, a transmissometer to measure light extinction, and a nephelometer to measure light scattering. Data from these sampling devices are used to determine the visibility status at the Jarbidge WA.

1.4.2 Emissions Analyses and Projections

USEPA's RHR requires statewide emission inventories of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I area. Nevada's inventories are presented in Chapter Three. These emissions inventories are available from the WRAP TSS (http://views.cira.colostate.edu/tssv2/Express/EmissionsTools.aspx). The TSS webpage has links to many references that describe in detail the emissions methods used in developing the point, area, mobile, dust, offshore and fire emission inventories.

Emissions scenarios used in the development of this SIP represent actual baseline emissions (2014v2), representative baseline emissions (RepBase2), and projected emissions (2028OTBa2 and 2028PAC2). The baseline period includes 2014 through 2018, represented by 2014, while the projected inventories denote 2028 emissions, as discussed below. The projected inventories take into account growth, "on-the-books" controls and regulations and the application of regional haze strategies. The year 2028 was selected as it represents the final year for demonstrating reasonable progress during the second implementation period. These inventories were used for visibility and source apportionment modeling.

The pollutants examined are sulfur dioxide (SO_2), sulfur oxides (SO_x), nitrogen oxides (NO_x), volatile organic compound (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (PM fine or $PM_{2.5}$), coarse particulate (PM coarse or PM_{10}) and ammonia (NH_3). It is important to note that each of these pollutants have characteristics that differ in terms of ability to affect visibility. Assuming one emission unit of PM fine, for example, the same unit of SO_2 or NO_x would be about three times more effective at impairing visibility. Organic carbon is about four times more effective and elemental carbon about ten times more effective at impairing visibility. (Primary organic aerosols and elemental carbon are discussed in Chapter Four as part of the weighted emissions potential analysis.) Conversely, PM coarse is about half as effective as PM fine. Both VOC and NH_3 affect visibility only after certain chemical reactions occur and, therefore, cannot be compared in this manner.

1.4.2.1 Preparation of Baseline Emissions Inventories

2014 Base Case (2014v2) Inventory

The 2014v2 inventory used actual data reported by states, locals, tribes and USEPA databases, which evolved from states' actual emissions data submitted to USEPA for the 2014 National Emission Inventory. The WRAP RHPWG for Emissions Inventories and Modeling Protocol (RHPWG EI & MP)[1] contracted with Ramboll to improve upon the 2014 WRAP emissions inventory.[2] WRAP states replaced the 2014v2 NEI source sectors as listed below:

1. California Air Resources Board (CARB) provided emissions for all anthropogenic sectors in California.

[1] https://views.cira.colostate.edu/wiki/wiki/9191/western-us-regional-analysis-2014-neiv2-emissions-inventory-review-for-regi

[2] https://www.wrapair2.org/pdf/WRAP%20Regional%20Haze%20SIP%20Emissions%20Inventory%20Review%20Documentation_for_Docket%20Feb2019.pdf

2. WRAP states updated emissions for electric generating units (EGU), non-EGU point sources, and onroad mobile.
3. The WRAP Oil and Gas Workgroup (OGWG)[3] and its contractor Ramboll, Inc., defined a Roadmap for updating oil and gas inventories and delivered updated 2014 emissions (October 2018) for Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming (emissions for remaining WRAP states remain as in the EPA 2014v2 platform). [4]
4. The WRAP Fire and Smoke Work Group (FSWG) updated the 2014NEIv2 BlueSky/SmartFire emissions.[5]
5. Natural emissions were developed by WRAP for 2014v2 and held constant at 2014v2 levels for the Representative Baseline and future year scenarios.
6. All other WRAP emissions sectors and all Non-WRAP emissions for WRAP 2014v2 were based on the EPA 2014 modeling platform.[6]

TABLE 1-1

WRAP CAMx/PSAT DATA SOURCES

Source Sector	2014v2	RepBase2	2028OTBa2
California All Sectors 12WUS2	CARB-2014v2	CARB-2014v2	CARB-2028
WRAP Fossil EGU w/ CEM	WRAP-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Fossil EGU w/o CEM	EPA-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Non-Fossil EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-WRAP EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
O&G WRAP O&G States	WRAP-2014v2	WRAP-RB-O&G [2]	WRAP-2028-O&G [2]
O&G WRAP Other States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
O&G non-WRAP States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
WRAP Non-EGU Point	WRAP-2014v2	WRAP-2014v2 [4]	WRAP-2014v2 [4]
Non-WRAP non-EGU Point	EPA-2014v2	EPA-2016v1	EPA-2016v1
On-Road Mobile 12WUS2	WRAP-2014v2	WRAP-2014v2	WRAP-2028-Mobile [5]
On-Road Mobile 36US	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-Road 12WUS2	EPA-2014v2	EPA-2016v1	WRAP-2028-Mobile [5]
Non-Road non-WRAP 36US	EPA-2014v2	EPA-2016v1 [6]	EPA-2028v1 [6]
Other (Non-Point) 12WUS2	EPA-2014v2	EPA-2014v2 [7]	EPA-2014v2 [7]
Other (Non-Point) 36US	EPA-2014v2	EPA-2016v1	EPA-2016v1
Can/Mex/Offshore 12WUS2	EPA-2014v2	EPA-2016v1	EPA-2016v1
Fires (WF, Rx, Ag)	WRAP-2014-Fires	WRAP-RB-Fires [8]	WRAP-RB-Fires [8]
Natural (Bio, etc.)	WRAP-2014v2	WRAP-2014v2	WRAP-2014v2
Boundary Conditions (BCs)	WRAP-2014-GEOS	WRAP-2014-GEOS	WRAP-2014-GEOS

1. WRAP-RepBase2-EGU and WRAP-2028OTBa2-EGU include changes/corrections/updates from WESTAR-WRAP states
2. WRAP-RepBase2-O&G and WRAP-2028OTBa2-O&G both include corrections for WESTAR-WRAP states.
3. O&G for other WRAP states and Non-WRAP states use EPA-2016v1 assumptions for 2028OTBa2 and unit-level changes provided by WESTAR-WRAP states.
4. WRAP-2014v2 Non-EGU Point is used for RepBase2 and 2028OTBa2, with source specific updates provided by WESTAR-WRAP states.
5. WRAP-2028-MOBILE is used for On-Road and Non-Road sources for the 12WUS2 domain.
6. EPA-2016v1 and EPA-2028v1 are used for On-Road and Non-Road Mobile for the 36km US domain.
7. Non-Point emissions use 2014v2 emissions for RepBase2 and 2028OTBa2 scenarios, including state-provided corrections.
8. RepBase fires are used for both RepBase2 and 2028OTBa2

[3] http://www.wrapair2.org/ogwg.aspx
[4] http://www.wrapair2.org/pdf/OGWG_Roadmap_FinalPhase1Report_Workplan_13Apr2018.pdf
[5] http://www.wrapair2.org/fswg.aspx
[6] https://www.epa.gov/air-emissions-modeling/2014-version-71-platform

The purpose of the 2014v2 scenario is to represent the actual conditions in calendar year 2014 with respect to ambient air quality and the associated sources of visibility-impairing air pollutants. The 2014v2 emissions inventories were used to validate the air quality model and associated databases and to demonstrate acceptable model performance with respect to replicating observed particulate matter air quality for use in the Comprehensive Air Quality Model with Extensions (CAMx) model performance evaluations.

2014 through 2018 Representative Baseline-Period (RepBase2) Inventory

The Representative Baseline (RepBase2) emissions scenario updates the 2014v2 inventory to account for changes and variation in emissions between 2014 and 2018 for key WRAP source sectors, as defined by the WRAP Emissions and Modeling Protocol subcommittee. The RepBase2 inventory was delivered as listed below:

1. California Air Resources Board (CARB) used the same source sector emissions as defined for 2014v2.
2. The WRAP EGU Emissions Analysis Project[7] developed a comprehensive database for fossil fuel electric generating units in 13 continental western states, including operating characteristics and emissions, for the period circa 2014-2018. Methods are defined in Center for New Energy Economy's analysis of WRAP fossil-fueled Electric Generating Units for Regional Haze Planning and Ozone Transport Contribution[8] (June 2019.)
3. The WRAP Oil and Gas Workgroup and its contractor, Ramboll, Inc., developed the circa2014 baseline oil and gas inventory[9] to apply to the RepBase inventory.
4. The WRAP Fire and Smoke Work Group (FSWG) worked with states, tribes, federal land managers and Air Sciences, Inc., to define 2014 to 2018 wildfire emissions for the Continental U.S. (36-km modeling grid) to represent a broader range of fire conditions (Representative Fire) than the single year 2014, as reported in Fire Emissions Inventories for Regional Haze Planning: Methods and Results.[10]
5. All other emissions sectors used the EPA 2016v1 platform[11] for RepBase2.

During state review of the Representative Baseline emissions, some errors and duplicate records were identified. WRAP states revised select EGU, non-EGU point, and oil and gas emissions for a revised Representative Baseline (RepBase2). Data sources for RepBase2 emissions are defined in Table 1-1. WRAP methods are further defined in Ramboll Inc.'s Run Specification Sheet for Representative Baseline (RepBase2) and 2028 On-the-Books (2028OTBa2) CAMx Simulations.[12]

[7] http://www.wrapair2.org/EGU.aspx
[8] https://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf
[9] http://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf
[10] http://www.wrapair2.org/pdf/fswg_rhp_fire-ei_final_report_20200519_FINAL.PDF
[11] https://www.epa.gov/air-emissions-modeling/2016-version-1-technical-support-document
[12] https://views.cira.colostate.edu/iwdw/docs/WAQS_and_WRAP_Regional_Haze_spec_sheets.aspx

1.4.2.2 Projected 2028 Emissions Inventories

2028 On-the-Books (2028OTBa2) Inventory
The WRAP 2028OTBa emissions inventory projection followed the methods applied by EPA in the September 2019 Technical Support Document[13] for updated 2028 regional haze modeling. The WRAP states updated source sectors to account for implementation by 2028 of all applicable federal and state requirements for U.S. anthropogenic emissions as listed below:

1. California Air Resources Board (CARB) provided 2028OTB projections from 2014v2 for all anthropogenic source sectors.
2. WRAP states worked with western utilities and the Center for New Energy Economy to project EGU emissions for 2028 On the Books, as reported in WRAP EGU emissions for Representative Baseline and 2028 On the Books projections.[14]
3. The WRAP Oil and Gas workgroup and its contractor, Ramboll, Inc., projected 2028 Oil and Gas area and point source emissions for WRAP states as reported in Revised Final Report: 2028 Future Year Oil and Gas Emission Inventory for WESTAR-WRAP States, March 2020 version.[15]
4. WRAP 2028 CAMx-ready emissions for on-road and non-road mobile sources, including offshore shipping, rail and airports are reported in Mobile Source Emissions Inventory 2028 Projections Project.[16]
5. Wildfire, Wildland Prescribed fire, and agricultural fires for the 2028OTBa inventory were identical to RepBase fires.

In September 2020, the WRAP states made revisions to select EGU, non-EGU, and oil and gas emissions for the WRAP states in the updated 2028OTBa2 projection. EPA 2016v1 emissions were assigned to some source sectors for WRAP, non-WRAP, Canada and Mexico in lieu of EPA 2028v1 emissions to provide more conservative assumptions for the 2028OTBa2 projection.

2028 Potential Additional Controls (PAC2) Inventory
Some, but not all, western states made various enhancements beyond the 2028OTBa inventory to represent Potential Additional Controls resulting from the four-factor analyses conducted for the second implementation period to achieve reasonable progress. These updates reflected decreases in visibility impairing pollutants and were used to evaluate the potential visibility response in 2028. WESTAR-WRAP States and source sectors modified in the 2028 Potential Additional Controls (PAC2) modeling scenario compared to 2028OTBa2 are defined in Table 1-2.

[13] https://www.epa.gov/sites/default/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf
[14] https://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf
[15] http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf
[16] http://views.cira.colostate.edu/wiki/wiki/11203/mobile-source-emissions-inventory-projections-project

TABLE 1-2

CHANGES TO 2028 PAC2 BY SOURCE SECTOR

2028PAC2 Changes to 2028OTBa2	EGU - Point	Non-EGU Point	Oil & Gas - Point	On-Road Mobile
Arizona (AZ)	X		X	
California (CA)				X
Colorado (CO)				
Idaho (ID)		X		
Montana (MT)	X			
Nevada (NV)	X	X		
New Mexico (NM)	X	X	X	
North Dakota (ND)	X			
Oregon (OR)	X	X	X	
South Dakota (SD)				
Utah (UT)				
Washington (WA)	X			
Wyoming (WY)				

Adjustments for the PAC2 modeling inventory were submitted to reflect potential reductions from control technology considered in draft four-factor analyses conducted by Nevada sources. Reductions achieved in the PAC2 inventory were based on assumptions relevant to the information of the draft four-factor analyses and do not represent final control determinations resulting from finalized four-factor analyses. Because of this, NDEP is not relying on the outputs of this model scenario for analyses in this SIP. Instead of using projected 2028 visibility conditions at Jarbidge WA from this model as Reasonable Progress Goals (RPGs) for the second implementation period, NDEP has made post-modeling adjustments to the RPGs calculated using the 2028OTBa2 model. This is discussed further in Chapter Six.

1.4.2.3 WRAP's Technical Support System

The Western Regional Air Partnership and Western Air Quality Study (WRAP-WAQS) 2014 Regional Haze modeling platform[17] is the latest of a series of regional modeling efforts supporting western U.S. air quality planning and management. The WRAP technical analyses follow the Environmental Protection Agency's (EPA) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze[18] (November 2018) and the Technical Support Document for EPA's updated 2028 regional haze modeling[19] (September 2019). The analyses fulfill the objectives of the WRAP 2018-2019 Workplan[20] as updated and approved by

[17] https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx
[18] https://www.epa.gov/sites/default/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf
[19] https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling
[20] http://www.wrapair2.org/pdf/2018-2019%20WRAP%20Workplan%20update%20Board%20Approved%20April.3.2019.pdf

the WRAP Board on April 3, 2019 and have been collectively designed, implemented, and reviewed by the WRAP Technical Steering Committee and its workgroups and subcommittees.

The Western Regional Air Partnership (WRAP) Technical Support System (TSS)[21] hosts the visibility monitoring, emissions, and air quality modeling analyses that support the 15 western states in developing regional haze state implementation plans (SIPs). This reference document describes the WRAP emissions and modeling analyses and illustrates how the TSS products can be applied and interpreted to support the 2028 visibility progress demonstrations for western U.S. Class I areas.

1.4.3 Air Quality Modeling

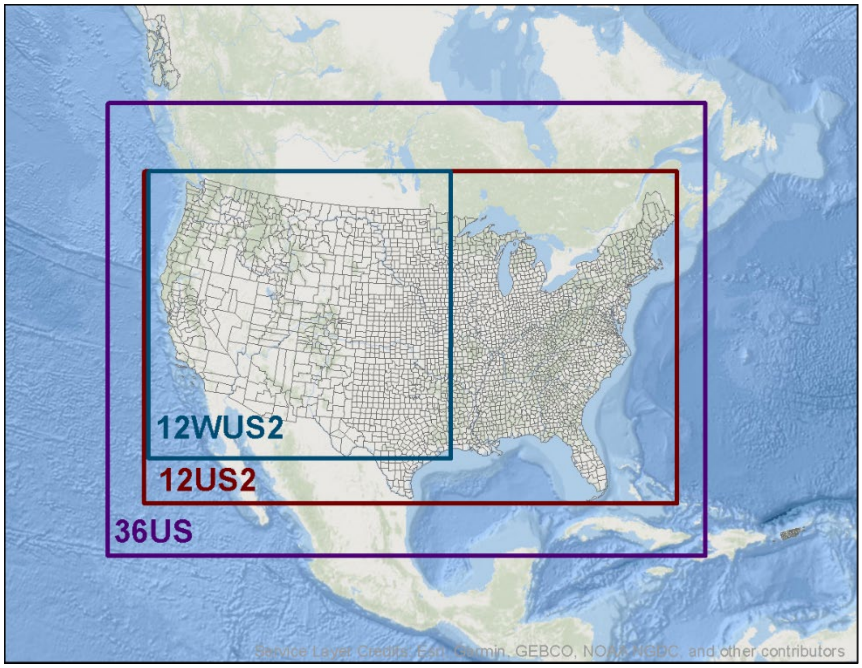
The sources of $PM_{2.5}$ are difficult to quantify because of the complex nature of their formation, transport and removal from the atmosphere. This makes it difficult to simply use emissions data to determine which pollutants should be controlled to most effectively improve visibility. Photochemical air quality models offer opportunity to better understand the sources of $PM_{2.5}$ by simulating the emissions of pollutants and the formation, transport and deposition of $PM_{2.5}$. If an air quality model performs well for an historical episode, the model may then be useful for identifying the sources of $PM_{2.5}$ and helping to select the most effective emissions reduction strategies for attaining visibility goals. Although several types of air quality modeling systems are available, the gridded, three-dimensional, Eulerian models provide the most complete spatial representation and the most comprehensive representation of processes affecting $PM_{2.5}$, especially for situations in which multiple pollutant sources interact to form $PM_{2.5}$.

The WRAP-WAQS 2014 modeling platform was developed and performed by Ramboll, Inc., under contract to WESTAR-WRAP. The 2014 modeling platform used the Weather Research and Forecasting (WRF) meteorological model, the Sparse Matrix Operator Kerner Emissions (SMOKE) model and the Comprehensive Air Quality Model with Extensions (CAMx) to project air quality for the 2014 base year. The Goddard Earth Observing System global chemical model (GEOS-Chem) provided global boundary conditions for the regional CAMx model for the 2014 base year. The CAMx 2014v2 final model configuration is defined in the WRAPWAQS 2014 modeling platform webpage. CAMx version 7beta 6 was used for the 2014v2 model performance run, while CAMx version 7.0 was used for the subsequent model scenarios. Figure 1-4 below illustrates the CAMx 36-km modeling domain covering the Continental United States and the 12-km modeling domain covering the western states.

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

FIGURE 1-4

WRAP-WAQS 2014 MODELING PLATFORM DOMAINS



Comprehensive Air Quality Model with Extensions
The CAMx model was initially developed by ENVIRON in the late 1990s as a nested-grid, gas-phase, Eulerian photochemical grid model. ENVIRON later revised CAMx to treat PM, visibility and air toxics.

In support of the WRAP regional haze air quality modeling efforts, Ramboll developed air quality modeling inputs including annual meteorology and emissions inventories for a 2014 actual emissions base case, a planning case to represent the 2014 through 2018 regional haze baseline period using averages for key emissions categories, and a 2028 on-the-books base case of projected emissions.

WRF is a next-generation mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs. WRF contains separate modules to compute different physical processes such as surface energy budgets and soil interactions, turbulence, cloud microphysics, and atmospheric radiation. Within WRF, the user has many options for selecting the different schemes for each type of physical process. There is a WRF Preprocessing System (WPS) that generates the initial and boundary conditions used by WRF, based on topographic datasets, land use information, and larger-scale atmospheric and oceanic models.

All emission inventories were developed using the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. Each of these inventories has undergone a number of revisions throughout the development process to arrive at the final versions used in the CAMx air quality modeling. The development of each of these emission scenarios is documented under the emissions inventory sections of the TSS. In addition to various sensitivities scenarios, the WRAP performed air quality model simulations for each of the emissions scenarios.

Boundary conditions specify the concentrations of gas and PM species at the four lateral boundaries of the model domain. Boundary conditions determine the amounts of gas and PM species that are transported into the model domain when winds flow is into the domain. Boundary conditions have a much larger effect on model simulations than do initial conditions. For some areas in the WRAP region and for clean conditions, the boundary conditions can be a substantial contributor to visibility impairment.

For this study boundary conditions data generated in an annual simulation of the global-scale GEOS-Chem model for calendar year 2014 were applied. Additional data processing of the GEOS-Chem data was required before using them in CAMx. The data first had to be mapped to the boundaries of the WRAP domain, and the gas and PM species had to be remapped to a set of species used in the CAMx model.

1.4.3.1 Visibility Modeling

The RHR goals include achieving natural visibility conditions at 156 federally mandated Class I areas by 2064. In more specific terms, that goal is defined as visibility improvement toward natural conditions for the 20 percent of days that have the most anthropogenically impaired visibility conditions (termed "20 percent most-impaired" visibility days), and no worsening in visibility for the 20 percent of days that have the clearest visibility ("20 percent clearest" visibility days). One component of the states' demonstration to USEPA that they are making reasonable progress toward this 2064 goal during the second implementation period is the comparison of modeled visibility projections for 2028 with what is termed a uniform rate of progress (URP) from baseline to natural conditions by 2064.

Preliminary 2028 visibility projections have been made using the 2028OTBa2 and PAC2 CAMx 36-km and 12-km modeling results, following USEPA guidance that recommends applying the modeling results in a relative sense to project future-year visibility conditions (U.S. EPA, 2001, 2003a, 2006). Projections are made using relative response factors (RRFs), which are defined as the ratio of the future-year modeling results to the current-year modeling results. The calculated RRFs are applied to the baseline observed visibility conditions to project future-year observed visibility. These projections can then be used to assess the effectiveness of the simulated emission control strategies that were included in the future-year modeling. The major features of USEPA's recommended visibility projections are as follows (U.S. EPA, 2003a,b, 2006):

- Monitoring data should be used to define current air quality.
- Monitored concentrations of PM_{10} are divided into six major components; the first five are assumed to be $PM_{2.5}$ and the sixth is $PM_{2.5-10}$.
  - SO_4 (sulfate)
  - NO_3 (particulate nitrate)
  - OC (organic carbon)
  - EC (elemental carbon)
  - OF (other fine particulate or soil)
  - CM (coarse matter).

- Models are used in a relative sense to develop RRFs between future and current predicted concentrations of each component.
- Component-specific RRFs are multiplied by current monitored values to estimate future component concentrations.
- Estimates of future component concentrations are consolidated to provide an estimate of future air quality.
- Future estimated air quality is compared with the goal for regional haze to see whether the simulated control strategy would result in the goal being met.
- It is acceptable to assume that all measured sulfate is in the form of ammonium sulfate [$(NH_4)_2SO_4$] and all particulate nitrate is in the form of ammonium nitrate [NH_4NO_3].

RRFs calculated from modeling results can be used to project future-year visibility. For the current modeling efforts, RRFs are the ratio of the 2028 modeling results to the 2014 modeling results and are specific to each Class I area and each PM species. RRFs are applied to the Baseline Condition observed PM species levels to project future-year PM levels, which are then used with the IMPROVE extinction equation listed above to assess visibility.

For all of the western Class I areas, the WRAP performed preliminary 2028 visibility projections and compared them to the 2028 URP using the 2028OTBa2 and PAC2 CAMx modeling results and the old and new IMPROVE equations.

1.4.3.2 Source Apportionment Modeling

Impairment of visibility in Class I areas is caused by a combination of local air pollutants and regional pollutants that are transported long distances. To develop effective visibility improvement strategies, the WRAP member states and tribes need to know the relative contributions of local and transported pollutants, and which emissions sources are significant contributors to visibility impairment at a given Class I area.

A variety of modeling and data analysis methods can be used to perform source apportionment of the PM observed at a given receptor site. One method is to implement a mass-tracking algorithm in the air quality model to explicitly track for a given emissions source the chemical transformations, transport and removal of the PM that was formed from that source. Mass-tracking methods have been implemented in the CAMx air quality model as PSAT.

Source apportionment for regional haze planning was conducted using various modeling techniques. The SO_x/NO_x Tracer and Organic Aerosol Tracer were performed using the regional PSAT air quality model. The WEP analysis included the synthesis of emissions data and meteorological back trajectories. The PMF Receptor Modeling and Causes of Dust analysis were complex statistical exercises involving IMPROVE monitoring data. Not all source apportionment techniques were applied to all pollutants.

Particulate Source Apportionment Technology

The main objective of applying CAMx/PSAT is to evaluate the regional haze air quality for conditions typical of the 2014 through 2018 representative baseline period (RepBase2) and future-year 2028 (2028OTBa2) conditions. These results are used:

- To assess the contributions of different geographic source regions (e.g., states) and source categories to current (2014-2018) and future (2028) visibility impairment at Class I areas, in order to obtain improved understanding of the causes of the impairment and which states are included in the area of influence of a given Class I area.
- To determine which source categories contributing to the area of influence for each Class I area are changing, and by how much, between the 2014 through 2018 and 2028 base cases. by varying only controllable anthropogenic emissions between the 2 PSAT simulations; and
- To identify the source regions and emissions categories that, if controlled to lower emissions rates than the 2028 base case levels, would produce the greatest visibility improvements at a Class I area.

The PSAT performs source apportionment based on user-defined source groups. A source group is the combination of a geographic source region and an emissions source category. Examples of source regions include states, nonattainment areas and counties. Examples of source categories include mobile sources, biogenic sources and elevated point sources; PSAT can even focus on individual sources. The user defines a geographic source region map to specify the source regions of interest. He or she then inputs each source category as separate, gridded low-level emissions and/or elevated-point-source emissions. The model then determines each source group by overlaying the source categories on the source region map. PM source apportionment modeling was performed for aerosol SO_4 and aerosol NO_3 and their related species (e.g., SO_2, NO, NO_2, HNO_3, NH_3, and NH_4).

The source apportionment model results are typically presented in two ways:

- *Spatial plots* showing the area of influence of a source group's PM species contributions throughout the model domain, either at a given hourly-average point in time or averaged over some time interval (e.g., monthly average).
- *Receptor bar plots* showing the rank order of source groupings that contribute to PM species at any given receptor site. These plots also can be at a particular point in time or averaged over selected time intervals—for example, the average source contributions for the 20 percent worst visibility days.

The primary products of the WRAP PSAT modeling were receptor bar plots showing the emission source groups that contribute the most to the model grid cells containing each IMPROVE monitoring site and other receptor sites identified by WRAP.

Two annual 36-km CAMx/PSAT model simulations were performed: one with the RepBase representative baseline case and the other with the 2028OTBa2 future-year case. It is expected that the states and tribes will use these results to assess the sources that contribute to visibility impairment at each Class I Area and to guide the choice of emission control strategies. The TSS web site includes a full set of source apportionment spatial plots and receptor bar plots for both RepBase2 and 2028OTBa2. These graphical displays of the PSAT results, as well as additional analyses of these results are available on the TSS under http://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx.

Additional information related to the CAMx air quality model and PSAT apportionment algorithm can be found at https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/SourceApportionmentSpecifications_WRAP_RepBase2_and_2028OTBa2_High-LevelPMandO3_and_Low-Level_PM_andOptionalO3_Sept29_2020.pdf.

Weighted Emissions Potential

The WEP was developed as a screening tool for states to decide which source regions have the potential to contribute to haze formation at specific Class I areas, based on both the 2002 and 2018 emissions inventories. This method does not produce highly accurate results because, unlike the air quality model and associated PSAT analysis, it does not account for chemistry and removal processes. Instead, it relies on an integration of gridded emissions data, back trajectory residence time data, a one-over-distance factor to approximate deposition and a normalization of the final results. Residence time over an area is indicative of general flow patterns, but does not necessarily imply the area contributed significantly to haze at a given receptor. Therefore, users are cautioned to view the WEP as one piece of a larger, more comprehensive weight of evidence analysis.

The emissions data used were the annual, 36km grid SMOKE-processed, model-ready emissions inventories provided by the WRAP. The analysis was performed for nine pollutants (maps were generated for all but the last three):

- Sulfur oxides
- Nitrogen oxides
- Organic carbon
- Elemental carbon
- Carbon monoxide
- Fine particulate matter
- Coarse particulate matter
- Ammonia
- Volatile organic carbon

The following source categories for each pollutant were identified and preserved through the analysis:

- Biogenic
- Natural fire
- Point
- Area
- WRAP oil and gas
- Off-shore
- On-road mobile
- Off-road mobile
- Road dust
- Fugitive dust
- Windblown dust
- Anthropogenic fires.

The back trajectory residence times were provided by the WRAP. The project used NOAA's HYSPLIT model to generate eight back trajectories daily for each WRAP Class I area for the entire five-year baseline period (2014 through 2018). From these individual trajectories, residence time fields were generated for one-degree latitude by one-degree longitude grid cells. Residence time analysis computes the amount of time (e.g., number of hours) or percent of time an air parcel is in a horizontal grid cell. Plotted on a map, residence time is shown as percent of total hours in each grid cell across the domain, thus allowing an interpretation of general air flow patterns for a given Class I area. The residence time fields for the 20 percent most impaired and clearest IMPROVE-monitored extinction days were selected for the WEP analysis to highlight the potential emissions sources during those specific periods.

The WEP analysis consisted of weighting the annual gridded emissions (by pollutant and source category) by the most impaired and clearest extinction days residence times for the five-year baseline period. To account for deposition along the trajectories, the result was further weighted by a one-over-distance factor, measured as the distance in km between the centroid of each emissions grid cell and the centroid of the grid cell containing the Class I area monitoring site under investigation. (The "home" grid cell of the monitoring site was weighted by one fourth of the 36km grid cell distance, or one-over-9km, to avoid a large response in that grid cell.) The resulting weighted emissions field was normalized by the highest grid cell to ease interpretation.

The WEP is not a rigorous, stand-alone analysis, but a simple, straightforward use of existing data. As such, there are several caveats to keep in mind when using WEP results as part of a comprehensive weight of evidence analysis:

- This analysis does not take into account any emissions chemistry.
- While actual emissions may vary considerably throughout the year, this analysis pairs up annual emissions data with 20 percent most impaired/clearest extinction days residence times – this is likely most problematic for carbon and dust emissions, which can be highly episodic.
- Coarse particle and some fine particle dust emissions tend not to be transported long distances due to their large mass.
- The WEP results are unitless numbers, normalized to the largest-valued grid cell. Effective use of these results requires an understanding of actual emissions values and their relative contribution to haze at a given Class I area.

Additional information regarding WEP analysis can be found at https://views.cira.colostate.edu/tssv2/WEP-AOI/.

1.5 REFERENCES

U.S. EPA 2003. Guidance for Tracking Progress under the Regional Haze Rule. EPA-454/B-03-004. September 2003.

U.S. EPA 2013. General Principles for 5-year Regional Haze Progress Reports. April 2013.

U.S. EPA 2018. Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. EPA-454/R-18-010. December 2018.

U.S. EPA 2019. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. EPA-457/B-19-003. August 2019.

U.S. EPA 2019. Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling. September 2019.

U.S. EPA 2020. Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. June 2020.

U.S. EPA 2021. Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period. July 2021.

Chapter Two – Baseline, Current, and Natural Visibility Conditions and Uniform Rate of Progress

2.1 INTRODUCTION

The goal of the Regional Haze Rule (RHR)(64 FR 35714) is the restoration of natural visibility conditions in the 156 mandatory Class I areas identified pursuant to the 1977 Clean Air Act Amendments. Federal visibility regulations detail how to establish goals to restore visibility to natural conditions by the year 2064 for the Class I areas. These regulations also require states to calculate baseline, current, and natural visibility conditions, which in turn are used to calculate the uniform rate of progress per year to achieve natural conditions by 2064.

The RHR defines visibility impairment as "any humanly perceptible difference due to air pollution from anthropogenic sources between actual visibility and natural visibility on one or more days." This alludes to natural visibility consisting of the difference between actual visibility conditions, and humanly perceptible changes in visibility due to anthropogenic air pollution.

Baseline visibility is the starting point for the improvement of visibility conditions. The baseline for this regional haze state implementation plan (SIP) is comprised of the years 2000 through 2004. Current conditions are assessed every five years as part of the SIP review, where actual progress in reducing visibility impairment is compared to the reductions committed to in the SIP. The current conditions for this regional haze SIP are the years 2014 through 2018.

The baseline and current visibility conditions for the Jarbidge Wilderness Area are based on measurements of particulate air pollution at the JARB1 Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring site, as discussed in Chapter One. The revised IMPROVE algorithm was used to calculate the Haze Index for the Jarbidge Wilderness Area.

This chapter presents and interprets the IMPROVE monitoring data to identify the role of individual components in visibility impairment at JARB1. The following chapters will present and interpret the emissions data and modeling results that, with this chapter, are the technical basis for determining Nevada's reasonable progress. The following paragraphs present a synopsis of the analyses of the IMPROVE monitoring data.

Analyses of the JARB1 monitor data have identified a baseline visibility condition of 8.73 deciviews (dv) and a current visibility condition of 7.97 dv. The natural visibility condition at Jarbidge WA is estimated to be 7.39 dv. Comparison of the initial baseline conditions or current conditions to natural visibility conditions indicates the amount of visibility improvement necessary to attain natural visibility conditions by 2064. The uniform rate of progress glidepath requires an average visibility condition at or below 8.20 dv during the most impaired days in 2028 in order to restore visibility back to natural conditions by 2064.

During the baseline period, organic matter carbon and elemental carbon extinction account for more than 35 percent of the total average annual reconstructed extinction at the JARB1 monitor for the 20 percent most impaired days. In addition, coarse and fine particle mass extinction account for an additional 23 percent of the average annual extinction at JARB1. Approximately 32 percent of the annual extinction budget is due to the formation of ammonium sulfate due to emissions of sulfur dioxide (SO_2) and approximately 9 percent of the annual extinction budget is due to the formation of ammonium nitrate due to emissions of nitrogen oxides (NO_x) from predominantly anthropogenic sources.

During the current period, organic matter carbon and elemental carbon extinction account for more than 35 percent of the total average annual reconstructed extinction at the JARB1 monitor for the 20 percent most impaired days. In addition, coarse and fine particle mass extinction account for an additional 30 percent of the average annual extinction at JARB1. Approximately 29 percent of the annual extinction budget is due to the formation of ammonium sulfate due to emissions of sulfur dioxide (SO_2) and approximately 5 percent of the annual extinction budget is due to the formation of ammonium nitrate due to emissions of nitrogen oxides (NO_x) from predominantly anthropogenic sources.

This data suggests significant contribution of natural fire emissions (indicated by high levels of organic matter carbon and elemental carbon) and windblown dust (indicated by high levels of coarse and fine particulate matter) to visibility impairment at the Jarbdige Wilderness Area. Among the two ambient air pollutants linked to anthropogenic emissions, ammonium sulfate and ammonium nitrate, it is clear that ammonium sulfate, or its precursor pollutant sulfur dioxide, is the primary anthropogenic pollutant of concern contributing to visibility impairment at the Jarbidge Wilderness Area.

2.2 BASELINE CONDITIONS FOR THE JARBIDGE WILDERNESS AREA

Baseline visibility is the annual average of the on-site IMPROVE monitoring data for the clearest days and most impaired days for the years 2000 through 2004, as specified in 40 CFR 51.308(f)(1). Nevada has established baseline visibility conditions for the clearest and most impaired visibility days at the Jarbidge Wilderness Area using data from IMPROVE monitor JARB1. The average was calculated for the years 2000 through 2004. The baseline calculations were made in accordance with 40 CFR 51.308(f)(1)(i) and USEPA's *Guidance for Tracking Progress Under the Regional Haze Rule* (EPA-454/B-03-004, September 2003).

Some IMPROVE sites, including JARB1, are missing complete data during this time period. JARB1 lacks complete data for the year 2000. To complete the missing data, USEPA published the Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period to provide states guidance on substituting missing data. Using the mechanisms listed in the guidance, JARB1 has complete data representing the 2000-2004 baseline. This new methodology constructs a new baseline using the Most Impaired Days metric, as opposed to Haziest Days, a new reading of current visibility conditions for the Most Impaired Days, and newly derived visibility for estimated Natural Conditions.

The baseline conditions are the average of the annual haze index calculated from the IMPROVE monitor data over the five-year baseline period 2000 through 2004 for both the 20 percent most impaired (8.73 dv) and 20 percent clearest (2.56 dv) days. Figures 2-1 and 2-2 are photographs of reference vistas representative of baseline extinction conditions for the clearest and most impaired days, respectively, at the Jarbidge Wilderness Area.

FIGURE 2-1

REFERENCE VISTA OF THE JARBIDGE WILDERNESS AREA
FOR BASELINE CLEAREST DAYS

Reference Vista: Mary's River Peak

Photo taken at 3:00 pm

Haze Index (HI) = 3 deciview

B_{ext} = 13 Mm^{-1}

Visual Range = 300 km / 186 mi

FIGURE 2-2

REFERENCE VISTA OF THE JARBIDGE WILDERNESS AREA
FOR BASELINE MOST IMPAIRED DAYS

Reference Vista: Mary's River Peak

Photo taken at 9:00 am

Haze Index (HI) = 8 deciviews

B_{ext} = 23 Mm^{-1}

Visual Range = 170 km / 106 mi

2.3 NATURAL CONDITIONS FOR THE JARBIDGE WILDERNESS AREA

Natural visibility represents the visibility condition that would be observed in the absence of human-caused impairment. The natural condition for each Class I area represents the visibility goal expressed in deciviews for the 20 percent most impaired and the 20 percent clearest days that would exist if there were only naturally occurring impairment. The 20 percent most impaired days natural conditions correspond to the long-term natural visibility goal. (40 CFR 51.308(f)(1)) Each state must estimate natural visibility levels for Class I areas within its borders in consultation with federal land managers (FLMs) and other states. 40 CFR 51.308(f)(1)(ii)

The natural conditions estimates were calculated consistent with USEPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). Adjustments were made to the natural visibility conditions during the most impaired days to account for impacts from international emissions and prescribed fire burning, as allowed by the most recent 2017 revision of the Regional Haze Rule. These adjustments are detailed further in Chapter Six. The natural background visibility for Jarbidge is 7.39 dv for the 20 percent most impaired days and 1.14 dv for the 20 percent clearest days.

Figures 2-3 is a photograph of a reference vista representative of natural extinction conditions for the clearest days at the Jarbidge Wilderness Area.

FIGURE 2-3

REFERENCE VISTA OF THE JARBIDGE WILDERNESS AREA
FOR NATURAL CONDITIONS CLEAREST DAYS

Reference Vista: Mary's River Peak

Photo taken at 9:00 am

Haze Index (HI) = 1 deciview

B_{ext} = 11 Mm^{-1}

Visual Range = 350 km / 218 mi

2.4 CURRENT CONDITIONS FOR THE JARBIDGE WILDERNESS AREA

Current visibility is the annual average of the most recent five years of data and were calculated by the WRAP states using IMPROVE monitoring data for the clearest days and most impaired days for the years 2014 through 2018.

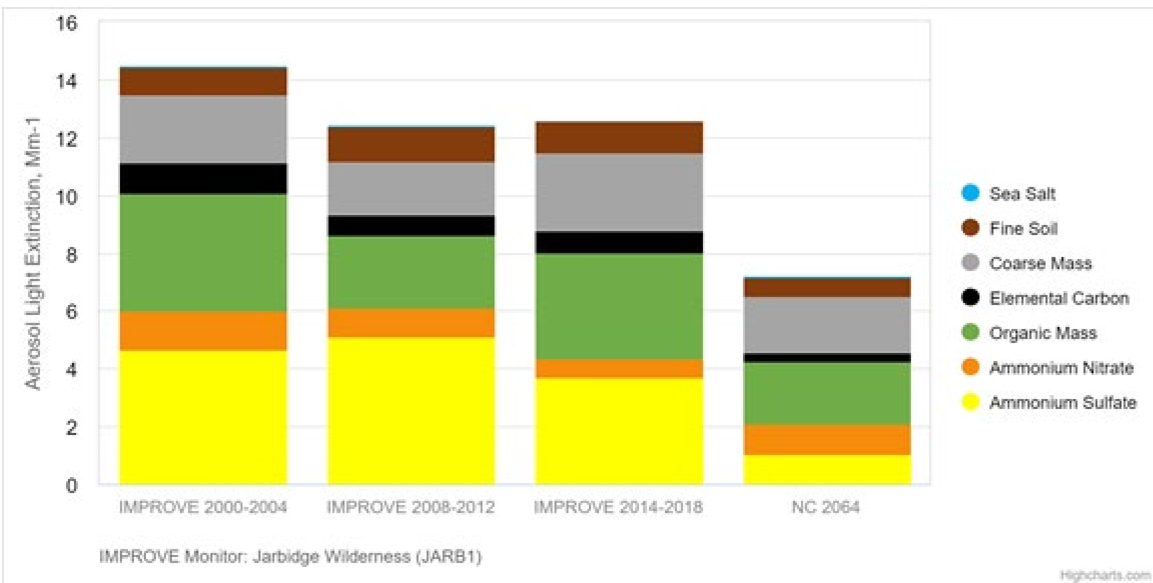
The current conditions are the average of the annual haze index calculated from the IMPROVE monitor data over the five-year current period 2014 through 2018 for both the 20 percent most impaired (7.97 dv) and 20 percent clearest (1.84 dv) days. Current visibility conditions at the Jarbidge Wilderness area were calculated for the 20 percent most impaired days and 20 percent clearest days in accordance with 40 CFR 51.308(f)(1)(iii).

2.5 PROGRESS TO DATE

Actual visibility progress to date for the 20 percent most impaired days at Jarbidge Wilderness area toward natural visibility conditions since the baseline period, previous implementation period, and current implementation period were calculated in accordance with 40 CFR 51.308(f)(1)(iv). As displayed in Figure 2-4, visibility conditions during the 20 percent most impaired days at Jarbidge Wilderness area show a general decrease in aerosol light extinction and show a consistent path toward natural conditions.

FIGURE 2-4

VISIBILITY PROGRESS TO DATE AT JARBIDGE WILDERNESS AREA
FOR MOST IMPAIRED DAYS



Although visibility at the Jarbidge Wilderness Area during the 20 most impaired days is generally improving toward the goal of natural conditions by 2064, IMPROVE monitoring data indicates that total aerosol light extinction observed during the current years 2014 through 2018 period slightly increased from the previous implementation period of years 2008 through 2012. As shown in Table 2-1, this is due to an increase in organic mass and coarse mass. Although the second implementation aims to remove episodic wildfire and windblown dust events from visibility analyses through use of the new most impaired days metric, this new method is not completely effective and still allows for episodic natural events to skew visibility data for regional haze purposes. Note that aerosol light extinction contributed by Ammonium Nitrate and Ammonium Sulfate decreased from the previous implementation period, confirming a decrease in anthropogenic emissions from the last round's efforts.

TABLE 2-1

VISIBILITY PROGRESS FOR THE MOST IMPAIRED DAYS
BY AEROSOL SPECIES

AEROSOL SPECIES (Mm^{-1})	IMPROVE 2000-2004	IMPROVE 2008-2012	IMPROVE 2014-2018	NC 1/1/2064
Ammonium Nitrate	1.36	0.98	0.66	1.03
Ammonium Sulfate	4.66	5.12	3.69	1.07
Coarse Mass	2.38	1.89	2.73	1.95
Elemental Carbon	1.03	0.66	0.72	0.31
Fine Soil	0.95	1.19	1.07	0.65
Organic Mass	4.07	2.55	3.70	2.14
Sea Salt	0.03	0.06	0.04	0.05
Deciview	8.73	7.88	7.97	5.23

Actual visibility progress to date for the 20 percent clearest days at Jarbidge Wilderness area toward natural visibility conditions since the baseline period, previous implementation period, and current implementation period were calculated in accordance with 40 CFR 51.308(f)(1)(iv). As displayed in Figure 2-5, visibility conditions during the 20 percent clearest days at Jarbidge Wilderness area show a general decrease in aerosol light extinction and confirm there has been no further degradation in visibility since the baseline period. Visibility conditions in deciviews listed in Table 2-2 also confirms this.

FIGURE 2-5

VISIBILITY PROGRESS TO DATE AT JARBIDGE WILDERNESS AREA
FOR THE CLEAREST DAYS

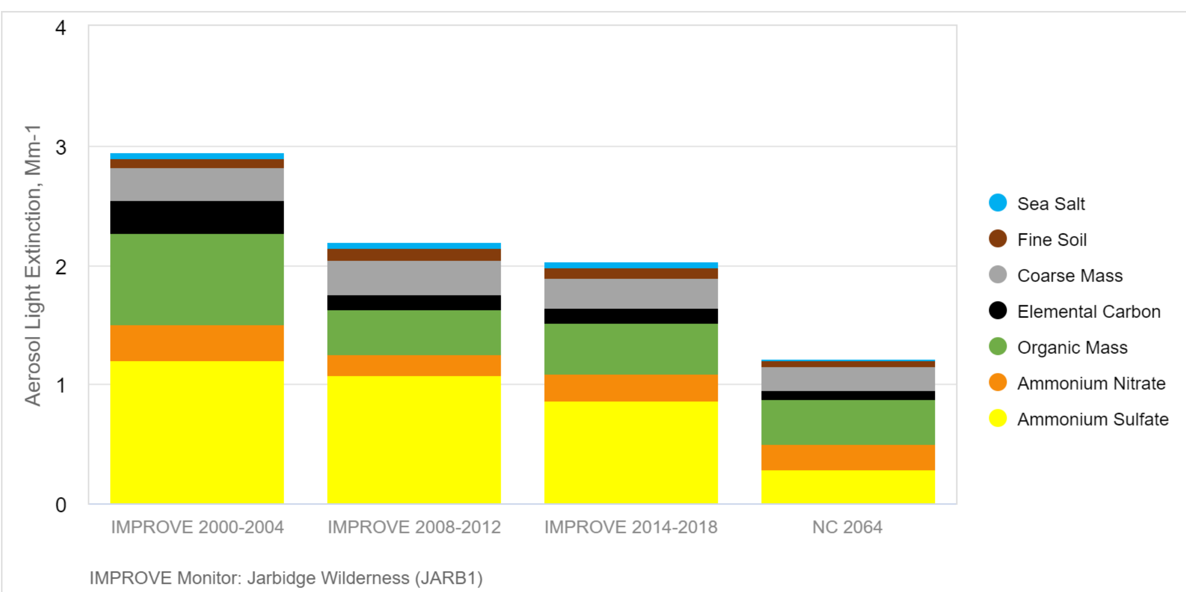


TABLE 2-2

VISIBILITY PROGRESS FOR THE CLEAREST DAYS
BY AEROSOL SPECIES

AEROSOL SPECIES (Mm^{-1})	IMPROVE 2000-2004	IMPROVE 2008-2012	IMPROVE 2014-2018	NC 1/1/2064
Ammonium Nitrate	0.291	0.181	0.218	0.211
Ammonium Sulfate	1.210	1.073	0.870	0.285
Coarse Mass	0.271	0.286	0.258	0.201
Elemental Carbon	0.276	0.125	0.124	0.073
Fine Soil	0.083	0.104	0.082	0.046
Organic Mass	0.771	0.381	0.428	0.385
Sea Salt	0.048	0.041	0.047	0.012
Deciview	2.565	1.963	1.837	1.140

Current conditions are calculated based on the average of the most recent five years of data and were calculated by the WRAP states using data from 2014-2018. Progress since the baseline (2000-2004) is indicated by taking the difference between current conditions and conditions during the baseline years. The difference between current and natural conditions indicates the remaining visibility improvements necessary to meet the goal of natural visibility by 2064. Table 2-3 shows the current conditions, progress made since the baseline and the remaining difference necessary toward attaining natural conditions by 2064. The difference between visibility conditions were calculated in accordance with 40 CFR 51.308(f)(1)(v), resulting in a difference between current and baseline conditions of 0.72 dv and 0.76 dv during the clearest days and most impaired days, respectively. The difference between current and natural conditions is 0.70 and 0.58 dv during the clearest days and most impaired days, respectively.

TABLE 2-3

DIFFERENCE BETWEEN VISIBILITY CONDITIONS

Class I Area	Current Conditions		Difference from Baseline		Difference from Natural	
	Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)
Jarbidge Wilderness Area (JARB1)	1.84	7.97	0.72	0.76	0.70	0.58

2.6 UNIFORM RATE OF PROGRESS GLIDEPATH TO NATURAL CONDITIONS IN 2064

Each state must set goals that provide for reasonable progress towards achieving natural visibility conditions by 2064. The reasonable progress goals must: 1) provide for improvement in visibility for the most impaired days over the period of the implementation plan; and 2) ensure no degradation in visibility for the least impaired days over the same period. States are directed to graphically show a uniform rate of progress (URP) toward natural visibility conditions for each Class I area within the State. The revised IMPROVE II algorithm was used for the calculation of the URP glidepath for the Jarbidge Wilderness Area.

A graph depicting the most impaired days glidepath for the Jarbidge Wilderness Area was developed in accordance with USEPA guidance for tracking progress (*Guidance for Setting Reasonable Progress Goals Under the Regional Haze Rule*, June 1, 2007), using data collected from the IMPROVE monitor JARB1. The glidepath is one of the indicators used to set reasonable progress goals and is simply a graph portraying a straight line drawn from the level of visibility impairment for the most impaired days baseline period to the natural background level with 2064 as the attainment date.

The URP is determined by the following equation, which calculates the slope of the glidepath in deciviews per year:

URP = (Baseline Condition – Natural Condition) / 60 years
URP = (8.73 dv – 7.39 dv) / 60 years
URP = 0.022 dv / year reduction

The uniform progress needed by 2028, the end of the second planning period, to achieve most impaired days natural visibility conditions by 2064 is calculated by multiplying the URP by the number of years in the first planning period (i.e. 2004 to 2028), as follows:

2028 URP = (URP) x (24 years)
2028 URP = 0.022 dv / year x 24 years
2028 URP = 0.536 dv reduction

The rule allows states to make adjustments to the URP endpoint to account for international and prescribed fire emissions, as they cannot be controlled. For an adjusted glidepath, haze contributions from international and prescribed fire emissions can be isolated through source apportionment modeling, discussed in Chapter Four, and added to the "natural conditions" endpoint in 2064. This decreases the slope of the URP glidepath and alters the visibility goal for 2028, as well as all other years.

Table 2-4 provides the URP data for the most impaired days and identifies the baseline for the clearest days. The baseline visibility for the 20 percent most impaired days at the Jarbidge Wilderness Area is calculated to be 8.73 dv. For the baseline 20 percent clearest days, visibility is calculated to be 2.56 dv. The URP glidepath is shown on Figure 2-6, which depicts the observed annual baseline visibility conditions by dark blue diamonds with the most impaired days baseline shown by the line through the dark blue diamonds. The glidepath for a URP toward reaching natural conditions is represented by the green, sloping line with triangles that identify specific URP values at five-year intervals. Natural conditions for the most impaired days are shown by the orange, horizontal line in the middle of the graph. The figure also shows the observed annual baseline conditions for the 20 percent clearest days by light blue diamonds with the baseline shown by the short line through the light blue diamonds. The reasonable progress goal must ensure no degradation in visibility during the clearest days from conditions observed during the baseline, or in other words, visibility conditions during the clearest days should not increase beyond 2.56 dv.

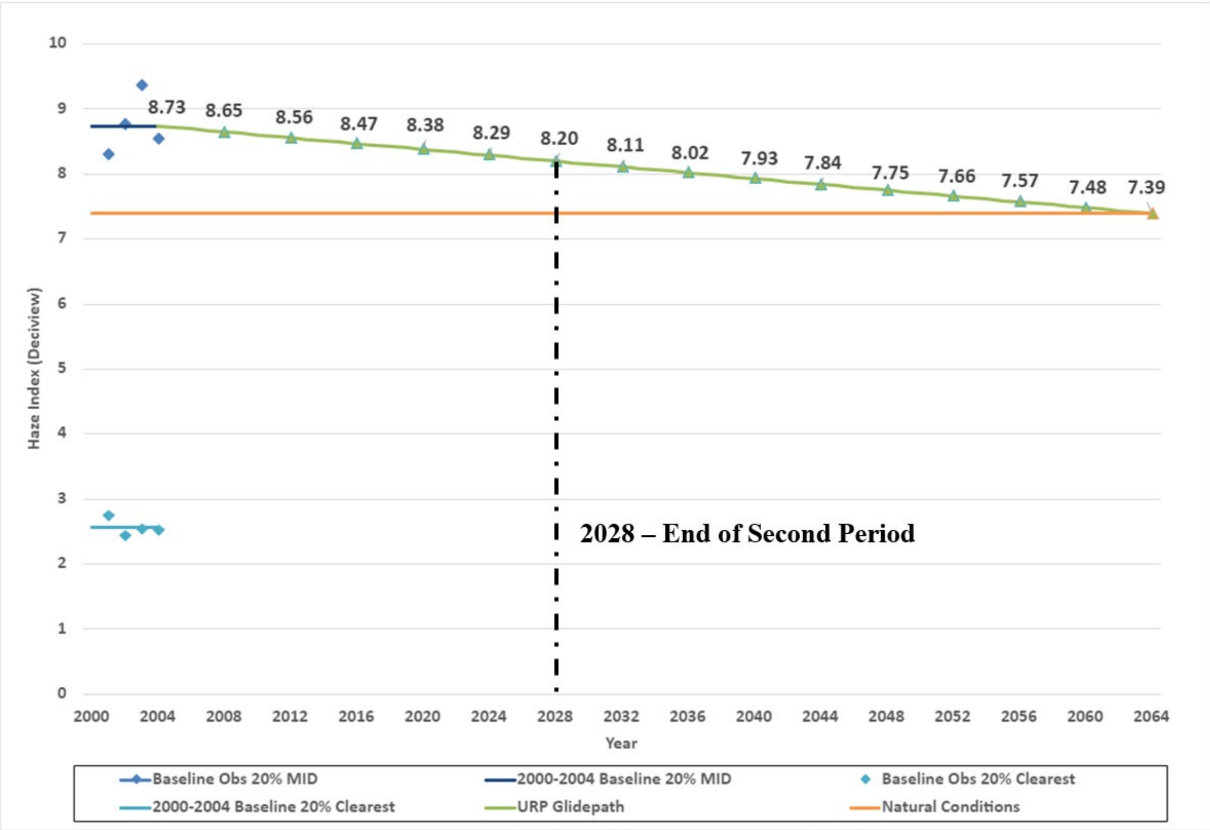
TABLE 2-4

UNIFORM RATE OF PROGRESS FOR THE
JARBIDGE WILDERNESS AREA

Class I Area	20% Most Impaired Days Baseline Condition (dv)	20% Most Impaired Days 2028 URP Goal (dv)	2028 Reduction Needed for 20% Most Impaired Days (dv)	20% Most Impaired Days 2064 Natural Conditions (dv)	2064 Reductions Needed for 20% Most Impaired Days (dv)	20% Clearest Days Baseline Condition (dv)
Jarbidge Wilderness Area	8.73	8.20	0.53	7.39	1.34	2.56

FIGURE 2-6

UNIFORM RATE OF PROGRESS GLIDEPATH FOR THE
JARBIDGE WILDERNESS AREA



2.7 HAZE IMPACTING PARTICLES – BASELINE PERIOD

Some of the fine particles that compose aerosols absorb light, while others reflect or scatter light, resulting in light extinction between the viewer and the light source. The IMPROVE monitor collects a 24-hour sample of these particles onto a filter, and they are analyzed at a laboratory to determine the standard components of the aerosol extinction.

Monitored Components

The monitored concentrations of PM_{10} are divided into six major components, the first five of which are assumed to be $PM_{2.5}$ and the sixth is $PM_{2.5-10}$. The monitored species are listed below by identifier with the common name in parenthesis.

- SO_4 (sulfate)
- NO_3 (particulate nitrate)
- OC (organic carbon)
- EC (elemental carbon)
- OF (other fine particulate or soil)
- CM (coarse matter)

The concentrations of these species are used in conjunction with the IMPROVE equation to calculate the light extinction.

Emission Species

The statewide emission inventory of pollutants that were used in the emission scenarios for this SIP include:

- SO_2 (Sulfur dioxide)
- NO_x (Nitrogen oxides)
- VOC (Volatile Organic Compounds)
- $PM_{2.5}$ (Particulate matter under 2.5 microns)
- PM_{10} (Particulate matter under 10 microns)
- NH_3 (Ammonia)
- CO (Carbon monoxide)

The baseline emissions and emission projections are discussed in detail in Chapter Three.

Extinction Species

Visibility conditions are then estimated by relating the IMPROVE 24-hour average PM mass measurements (i.e. concentration data for the species listed above) to the PM components of light extinction as identified in the IMPROVE equation. The extinction components are listed below. The bold text indicates how the monitored extinction components will be identified in the remainder of the SIP.

- Ammonium sulfate [$(NH_4)_2SO_4$] or **SO_4**
- Particulate ammonium nitrate [$(NH_4)NO_3$] or **NO_3**
- Organic matter carbon [**OMC**]
- Elemental carbon [**EC**]
- Fine soil [**SOIL**]
- Coarse matter [**CM**]

- **Sea Salt**

2.7.1 Aerosol Composition for the Jarbidge Wilderness Area

Analyses of the IMPROVE monitor data provides important insight to the relative importance of the components of measured visibility impairing pollutants. The monitoring data for the 20 percent most impaired, 20 percent clearest, and IMPROVE sample days were analyzed on an annual, monthly, and daily basis to evaluate the causes of visibility impairment during the baseline period.

2.7.1.1 Summary of Aerosol Composition at the Jarbidge Wilderness Area

This section describes the aerosol composition observed at the JARB1 IMPROVE monitor during the baseline period. The following sections present the monitoring data for the 20 percent most impaired days, 20 percent clearest days, and all IMPROVE sample days.

Organic matter carbon (OMC) is the most important contributor to fine particulate mass and light extinction on the most impaired days and for all IMPROVE sample days. OMC is also a significant contributor on the least impaired days of the baseline period at JARB1. Elevated levels of OMC and EC and their seasonal signature suggest impact from fire and biogenic sources, which are significant natural sources of primary organic aerosol (POA) and volatile organic compounds (VOCs), which are components of OMC. Anthropogenic emissions contributing to OMC include carbon from combustion of fossil fuels and wood burning but are not likely significant sources of OC emissions at this rural site. However significant visibility impacts due to OC emissions from natural fire events are common at the Jarbidge Wilderness Area and explain the large daily, seasonal, and annual variations of the reconstructed OMC extinction described in the next sections.

Coarse matter (CM) or particulate matter with particles having diameters between 2.5 and 10 microns is the second most important contributor to reconstructed extinction for the most impaired days of the baseline period. CM has a relatively small contribution to visibility impairment on the clearest days but is a significant contributor to visibility impairment for IMPROVE sample days. The light extinction efficiency of CM is very low compared to the extinction efficiency for sulfate, nitrate, and carbon, as described in Chapter One. The significant CM contributions to reconstructed extinction suggest the seasonal importance of local and regional transport of particulate matter due to naturally occurring windblown dust events.

Ammonium sulfate (SO_4) or sulfate is an important contributor to visibility impairment at JARB1 for the most impaired days and IMPROVE sample days. SO_4 is the most significant contributor on the clearest days. Sulfate particles are formed in the atmosphere from SO_2 emissions. Sulfate particles occur as hydrogen sulfate, ammonium bisulfate and ammonium sulfate depending on the availability of ammonia in the atmosphere. Although SO_4 contributions show some seasonal increases during the summer months, the lack of daily variability suggests the sulfate contributions are influenced by regional transport rather than local sources.

Soil (SOIL) or particulate matter with particles having diameters less than 2.5 microns is a minor contributor to reconstructed extinction for the most impaired, clearest and IMPROVE sample days of the baseline period. Episodes of relatively high SOIL contribution coupled with relative high CM contributions may be indicative of local and regional seasonal transport of particulate matter due to windblown dust events. Occasionally, elevated SOIL can be attributed to long-range transport of international dust episodes originating outside the US.

Elemental carbon (EC) is a minor contributor to visibility impairment at JARB1 for the most impaired, clearest and IMPROVE sample days of the baseline period. The light extinction efficiency of EC is high compared to the extinction efficiency for sulfate, nitrate and carbon, as described in Chapter One. Common sources of EC emissions are fire, including agricultural burning, prescribed fire, and natural fire, as well as incomplete combustion of fossil fuels. The seasonality and common trend shared with OMC extinction suggest fire emissions may also be the dominant source of EC extinction at JARB1.

Ammonium nitrate (NO_3) or nitrate is a minor contributor to reconstructed extinction for the most impaired, clearest and IMPROVE sample days of the baseline period at JARB1. However, NO_3 is a significant contributor for some individual days. NO_3 is formed in the atmosphere by the reaction of ammonia (NH_3) and nitrogen oxides (NO_x). NO_3 formation is limited by the availability of ammonia and temperature. Ammonia preferentially reacts with SO_2 and sulfate before reacting with NO_x. Particle nitrate is formed at lower temperatures, so NO_3 levels are lower in the summer months and higher in the winter months. Therefore, the relative NO_3 contribution to visibility impairment is seasonal as identified below. NO_x emissions are the result of fossil fuel combustion by point, area, on-road, and off-road mobile sources. The relatively minor contribution of NO_3 to reconstructed extinction at JARB1 suggests that formation is limited by both the availability of ammonia and the paucity of NO_x sources in this rural setting.

Sea Salt is a trace contributor to reconstructed extinction at JARB1. The new IMPROVE equation uses the chlorine ion from routine IMPROVE measurements to calculate sea salt levels, accounting for the occasional contribution of SEA SALT to extinction at JARB1.

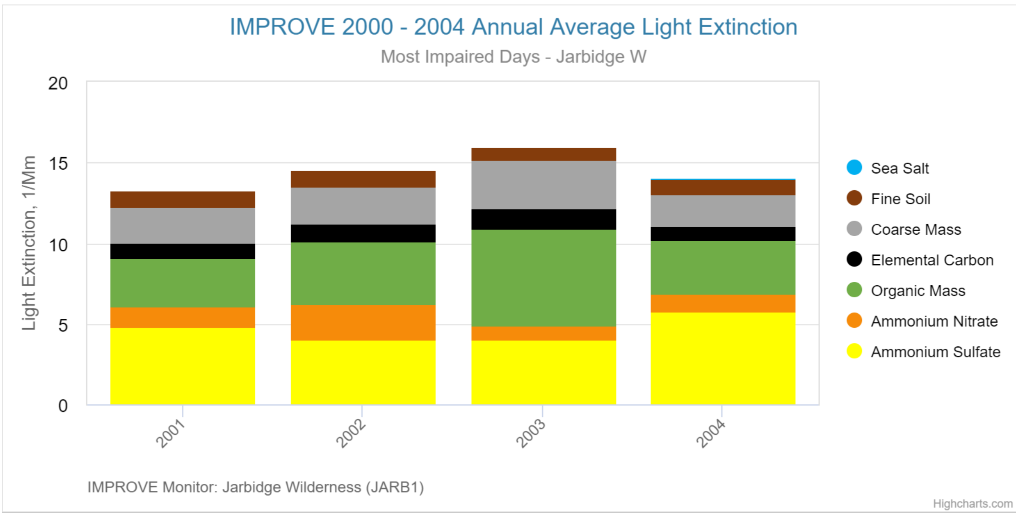
2.7.1.2 20 Percent Most impaired Days

<u>*Baseline Conditions*</u>
Figure 2-8 shows the annual reconstructed light extinction over the baseline period based on monitor data from JARB1 site for the 20 percent most impaired days. The variability of annual most impaired days reconstructed light extinction is nearly 3 Mm^{-1}.

The line graph shown as Figure 2-9 shows the individual components of the reconstructed light extinction over the baseline period based on JARB1 IMPROVE data for the 20 percent most impaired days. OMC and SO_4 are the most significant contributors to visibility impairment at JARB1 for the baseline period, followed by CM and NO_3. Soil, EC, and Sea Salt are less significant but sub-equal contributors to visibility impairment for the baseline period.

FIGURE 2-8

ANNUAL RECONSTRUCTED EXTINCTION FOR MOST IMPAIRED DAYS
OF THE BASELINE PERIOD



The baseline period annual variation for OMC is 3 Mm^{-1}, indicating the large range of annual effects produced by fire emissions, one of the dominant sources of OMC. Although 2002 was a bad fire year in the western US, OMC levels in 2003 spiked, as reflected on Figure 2-9 by the OMC trend. Days selected for the 20% most impaired days in 2003 may not have effectively screened out days impacted by wildfire, resulting in the spike seen in 2003.

FIGURE 2-9

ANNUAL RECONSTRUCTED EXTINCTION BY SPECIES FOR
MOST IMPAIRED DAYS OF BASELINE PERIOD

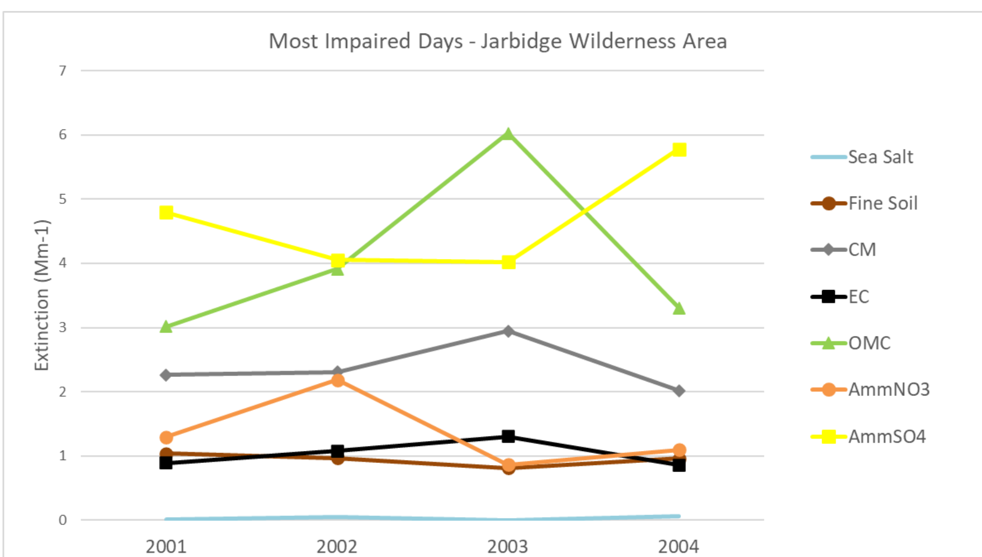
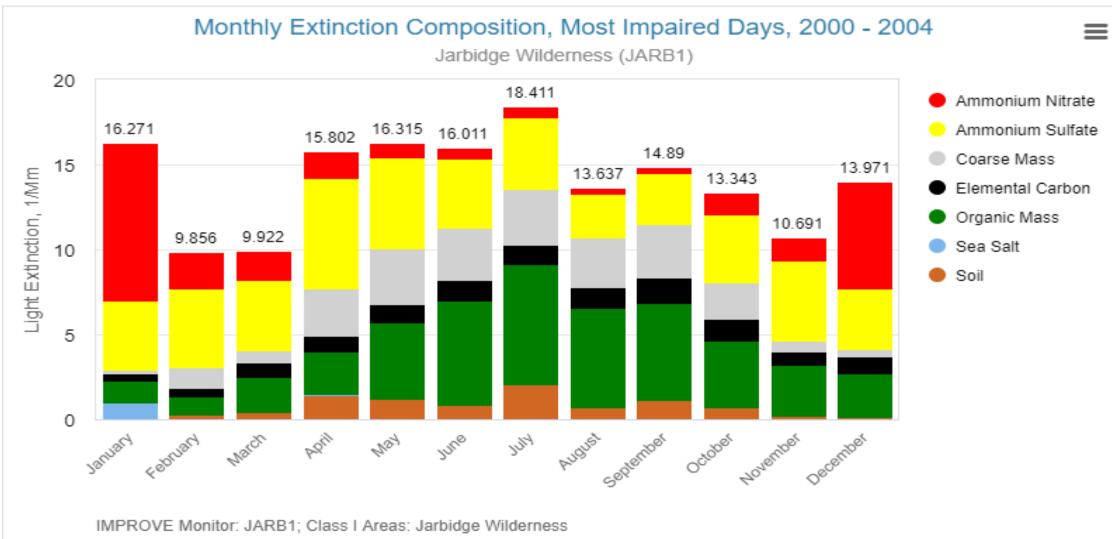


Figure 2-10 displays the monthly distribution of the reconstructed extinction for the 20 percent most impaired days averaged over the baseline period yea for the Jarbidge Wilderness Area. The most impaired days are generally summer events, occurring during the period April to the end of July of each year. Fires, dust events, and photochemical processes are elevated during this time frame, which maximizes OMC concentrations, CM and SOIL concentrations, and secondary particulate formation. Ammonium Sulfate remains a constant contributor to light extinction year-round with smaller variances, reinforcing that it is the primary anthropogenic pollutant at Jarbidge Wilderness Area. Ammonium nitrate contributions spike during the winter months of December and January.

FIGURE 2-10

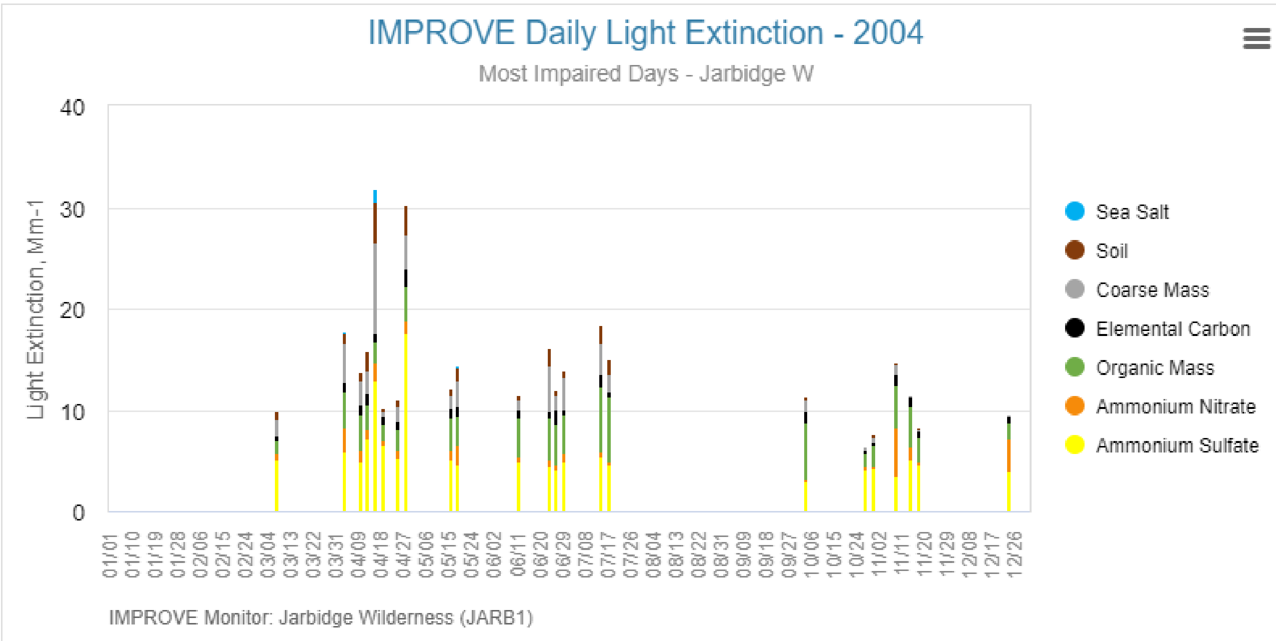
<u>MONTHLY DISTRIBUTION OF MOST IMPAIRED DAYS OF BASELINE PERIOD</u>



Daily reconstructed light extinction for the 20 percent most impaired days of the final baseline year, 2004, at JARB1 is presented in Figure 2-11 and shows SO_4 and OMC are generally the largest components of visibility impairment on the most impaired days at the Jarbidge Wilderness Area. EC and NO_3 are significant components for a handful of days.

FIGURE 2-11

DAILY RECONSTRUCTED LIGHT EXTINCTION FOR
MOST IMPAIRED DAYS OF BASELINE PERIOD

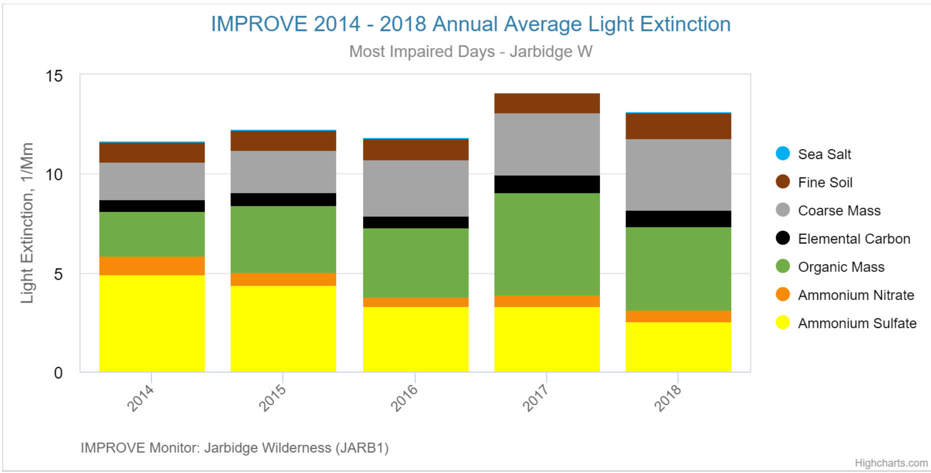


Current Conditions
Figure 2-12 shows the annual reconstructed light extinction over the current period based on monitor data from JARB1 site for the 20 percent most impaired days. The variability of annual most impaired days reconstructed light extinction is nearly 3 Mm^{-1}.

The line graph shown as Figure 2-13 shows the individual components of the reconstructed light extinction over the current period based on JARB1 IMPROVE data for the 20 percent most impaired days. OMC and SO_4 are the most significant contributors to visibility impairment at JARB1 for the baseline period, followed by CM. Although SO_4 is the largest contributor to light extinction at Jarbidge Wilderness area during the first two years of the current period, it shows a downward trend, falling below OMC and CM by 2018. OMC and CM show an increasing trend through the entire current period. This indicates that light extinction due to SO_4 is decreasing due to reductions in SO_2 emissions, and also indicates that wildfire and windblown dust events are increasing in occurrence near the Jarbidge Wilderness area. Soil, EC, and Sea Salt are less significant but sub-equal contributors to visibility impairment for the baseline period.

FIGURE 2-12

ANNUAL RECONSTRUCTED EXTINCTION FOR MOST IMPAIRED DAYS
<u>OF THE CURRENT PERIOD</u>



The current period annual variation for Coarse Mass is 2 Mm^{-1}, and the current period annual variation for OMC is 3 Mm^{-1}, indicating the large range of annual effects produced by fire emissions, one of the dominant sources of OMC and CM. In recent years, the drier climates of the western states have experienced an increase in wildfire activity during the summer months. Days selected for the 20% most impaired days in 2017 and 2018 may not have effectively screened out days impacted by wildfire and windblown dust, resulting in the spikes seen in 2017 and 2018.

FIGURE 2-13

ANNUAL RECONSTRUCTED EXTINCTION BY SPECIES FOR
<u>MOST IMPAIRED DAYS OF CURRENT PERIOD</u>

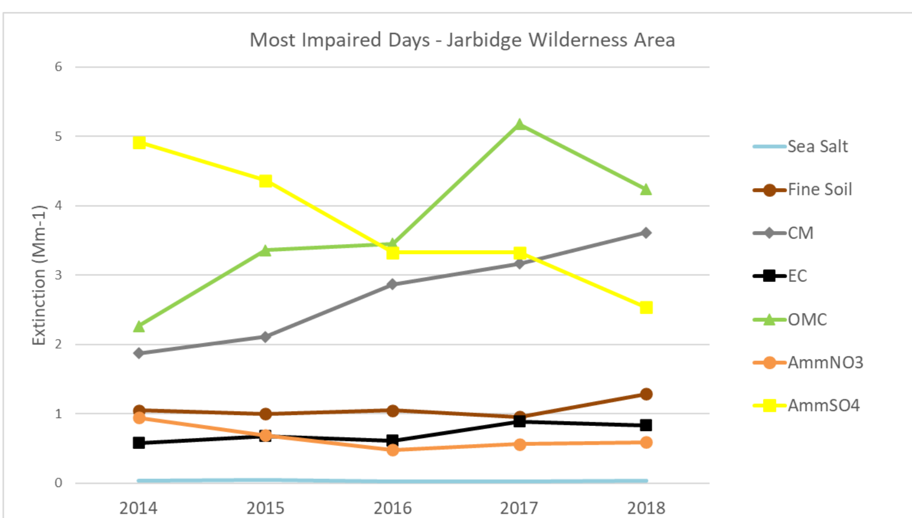
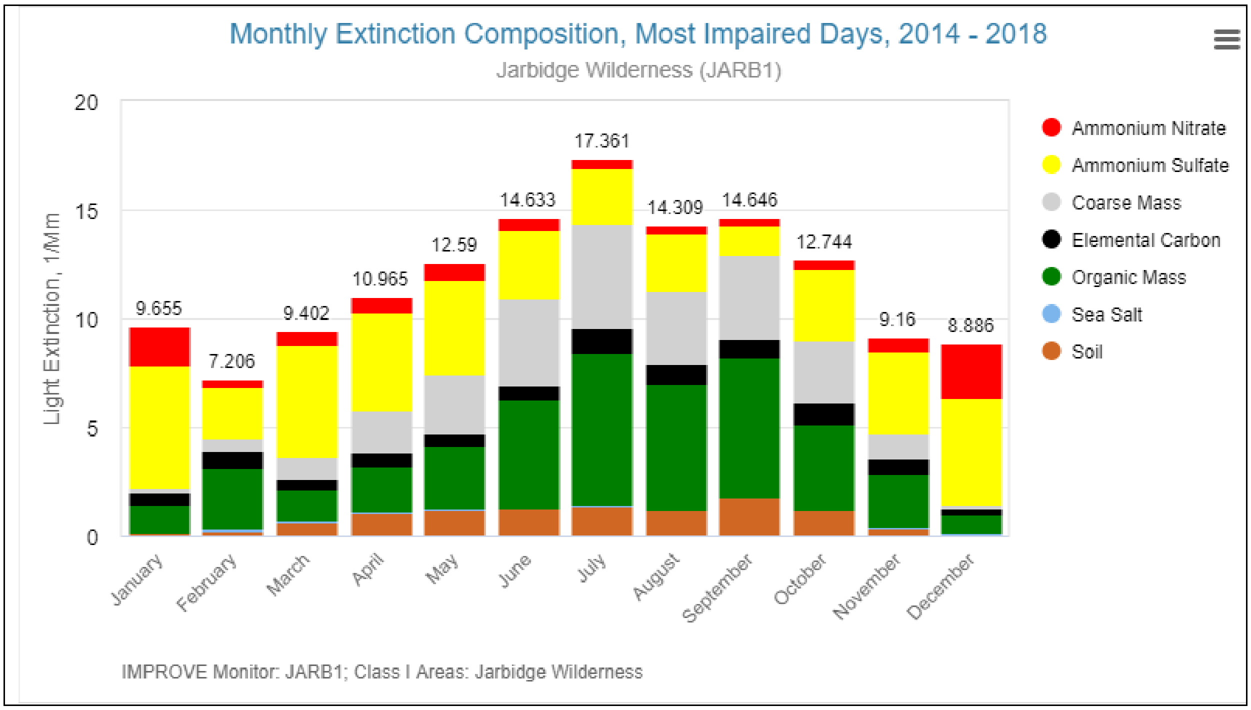


Figure 2-14 displays the monthly distribution of the reconstructed extinction for the 20 percent most impaired days averaged over the current period years for the Jarbidge Wilderness Area. The most impaired days are generally summer events, occurring during the period April to the end of October. Fires, dust events, and photochemical processes are elevated during this time frame, which maximizes OMC concentrations, CM and SOIL concentrations, and secondary particulate formation. Ammonium Sulfate remains a constant contributor to light extinction year-round with smaller variances, reinforcing that it is the primary anthropogenic pollutant at Jarbidge Wilderness Area. Ammonium nitrate contributions spike during the winter months of December and January.

FIGURE 2-14

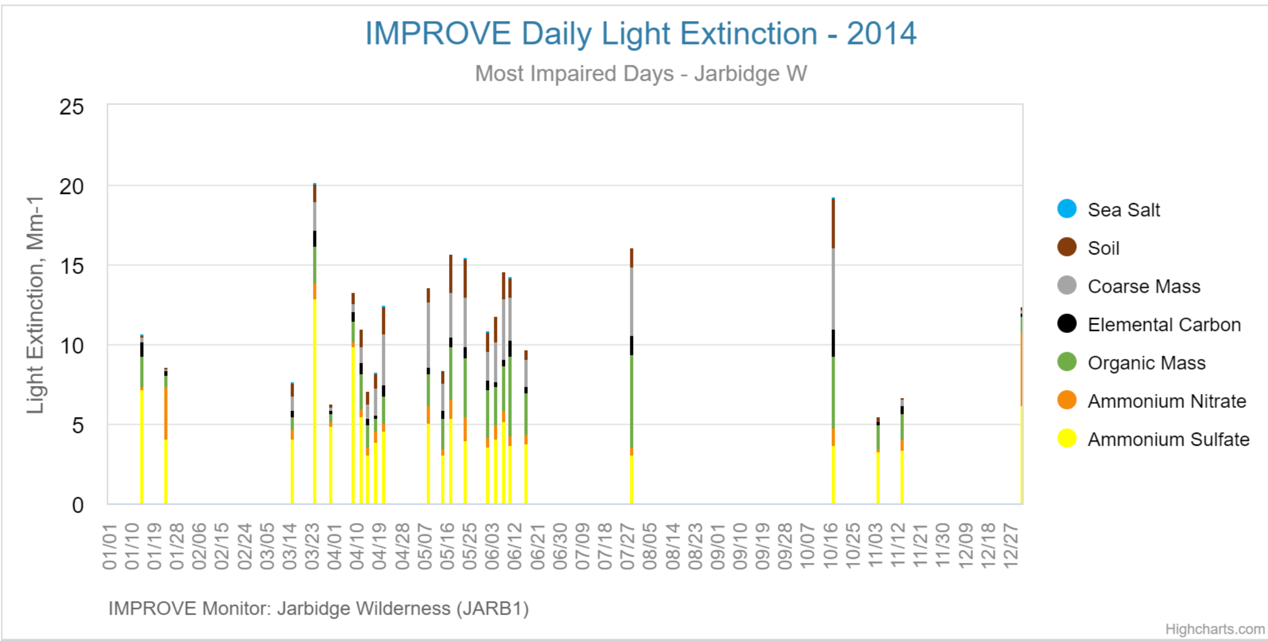
<u>MONTHLY DISTRIBUTION OF MOST IMPAIRED DAYS OF CURRENT PERIOD</u>



Daily reconstructed light extinction for the 20 percent most impaired days in 2014, the base year utilized for regional modeling, at JARB1 is presented in Figure 2-15 and shows SO_4 and OMC are generally the largest components of visibility impairment on the most impaired days at the Jarbidge Wilderness Area. CM is a significant component for a handful of days.

FIGURE 2-15

DAILY RECONSTRUCTED LIGHT EXTINCTION FOR
<u>MOST IMPAIRED DAYS OF CURRENT PERIOD</u>

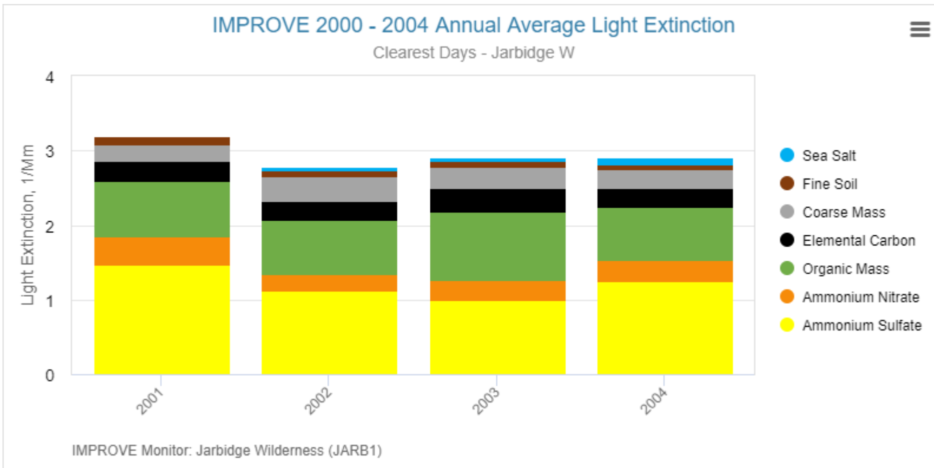


2.7.1.3 20 Percent Clearest Days

<u>Baseline Conditions</u>
The bar graph shown in Figure 2-16 shows the reconstructed light extinction over the baseline period for the 20 percent clearest days based on data from JARB1. Note the baseline period annual variation is less than 0.5 Mm^{-1} for the clearest days, much less than the variability shown for the most impaired days.

FIGURE 2-16

ANNUAL RECONSTRUCTED EXTINCTION FOR
CLEAREST DAYS OF BASELINE PERIOD



The line graph in Figure 2-17 shows the individual components of the reconstructed light extinction over the baseline period for the 20 percent clearest days at JARB1. SO_4 and OMC are the most significant contributors to visibility impairment for the clearest days of the baseline period, followed by sub-equal contributions from NO_3, EC, and CM. SOIL is a minor contributor to visibility impairment for the clearest days. SO_4 has approximately 0.5 Mm^{-1} variation, while OMC has approximately 0.2 Mm^{-1} variation for the clearest days of the baseline period.

FIGURE 2-17

ANNUAL RECONSTRUCTED EXTINCTION BY SPECIES FOR
CLEAREST DAYS OF BASELINE PERIOD

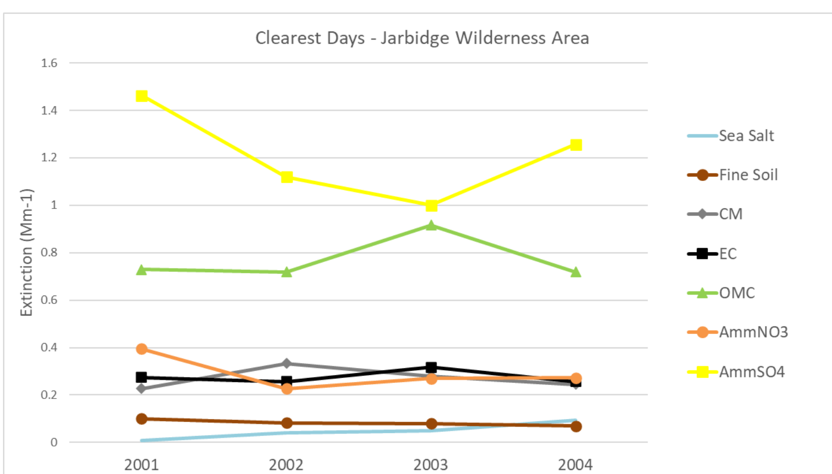
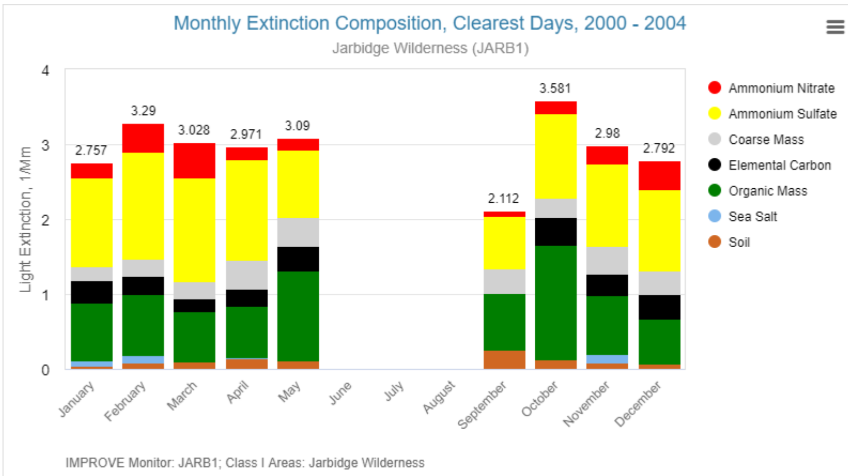


Figure 2-18 displays the monthly distribution of the reconstruction extinction for the 20 percent clearest days of the final baseline period for JARB1. The clearest days are generally winter events occurring from October to May of each year, when fires, dust events, and photochemical processes are at a minimum.

FIGURE 2-18

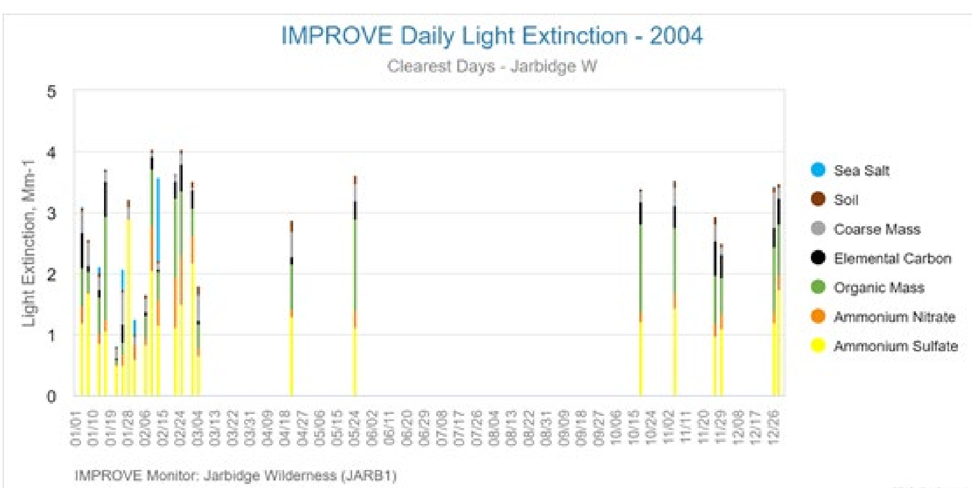
MONTHLY DISTRIBUTION OF CLEAREST DAYS OF BASELINE PERIOD



Daily reconstructed light extinction for the 20 percent clearest days of the baseline period at JARB1 is presented in Figure 2-19 and shows OMC and/or SO_4 are generally the largest components of visibility impairment on the clearest days at the Jarbidge Wilderness Area. NO_3, CM, and Sea Salt are significant components for a handful of days.

FIGURE 2-19

DAILY RECONSTRUCTED LIGHT EXTINCTION FOR
CLEAREST DAYS OF BASELINE PERIOD

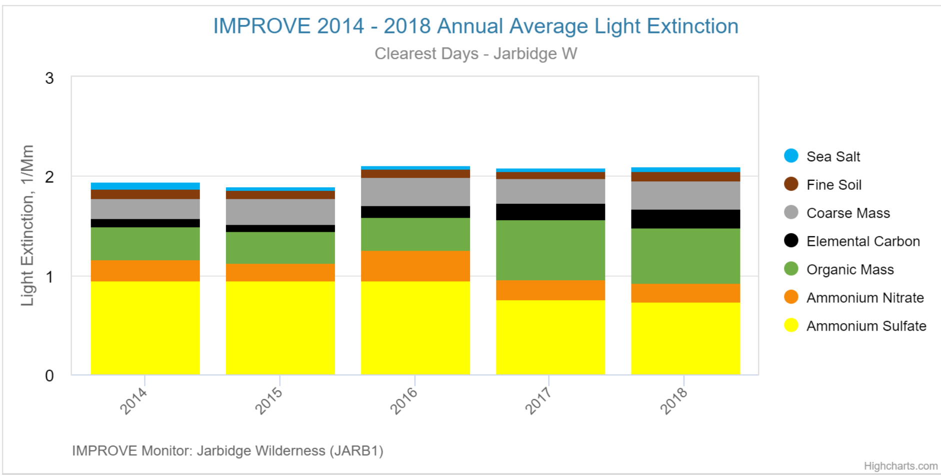


Current Conditions

The bar graph shown in Figure 2-20 shows the reconstructed light extinction over the current period for the 20 percent clearest days based on data from JARB1. Note the current period annual variation is less than 0.5 Mm^{-1} for the clearest days, much less than the variability shown for the most impaired days.

FIGURE 2-20

ANNUAL RECONSTRUCTED EXTINCTION FOR
CLEAREST DAYS OF CURRENT PERIOD



The line graph in Figure 2-21 shows the individual components of the reconstructed light extinction over the current period for the 20 percent clearest days at JARB1. SO_4 and OMC are the most significant contributors to visibility impairment for the clearest days of the current period, followed by sub-equal contributions from NO_3, EC, and CM. SOIL is a minor contributor to visibility impairment for the clearest days. SO_4 has approximately 0.2 Mm^{-1} variation, while OMC has approximately 0.2 Mm^{-1} variation for the clearest days of the baseline period. In most recent years, SO_4 appears to be decreasing, while OMC appears to be increasing.

FIGURE 2-21

ANNUAL RECONSTRUCTED EXTINCTION BY SPECIES FOR
CLEAREST DAYS OF CURRENT PERIOD

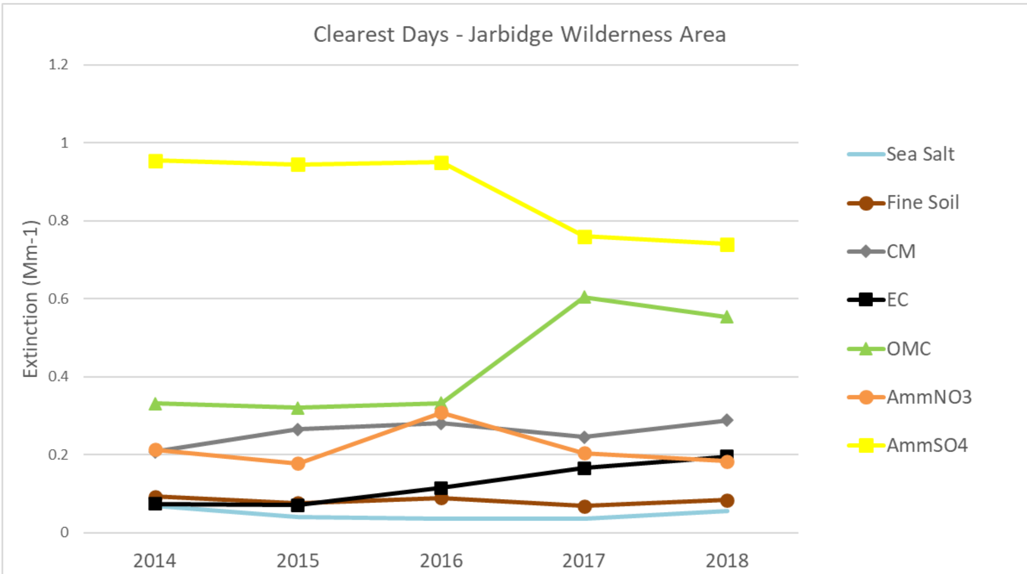
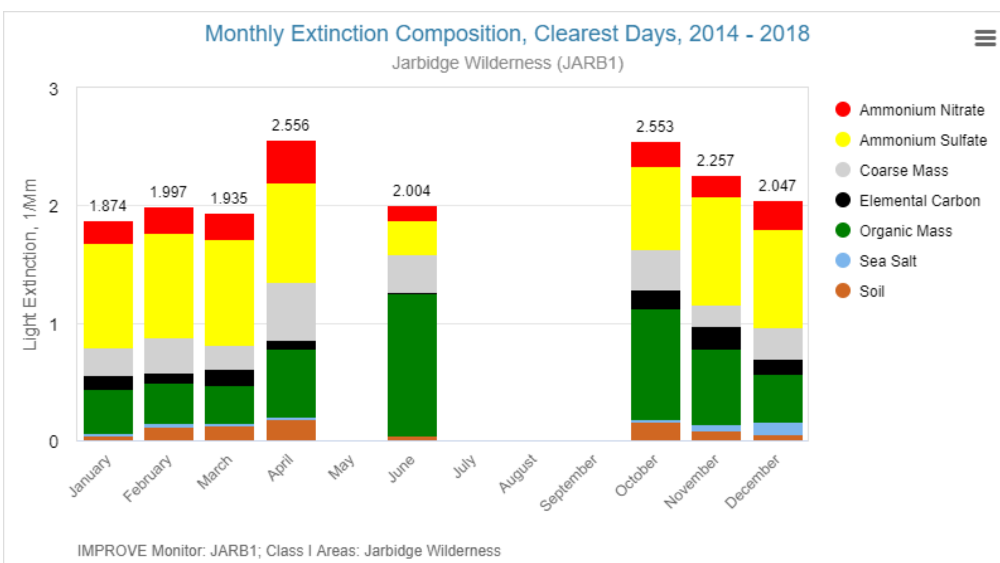


Figure 2-22 displays the monthly distribution of the reconstruction extinction for the 20 percent clearest days of the current period for JARB1. The clearest days are generally winter events occurring from October to April of each year, when fires, dust events, and photochemical processes are at a minimum.

FIGURE 2-22

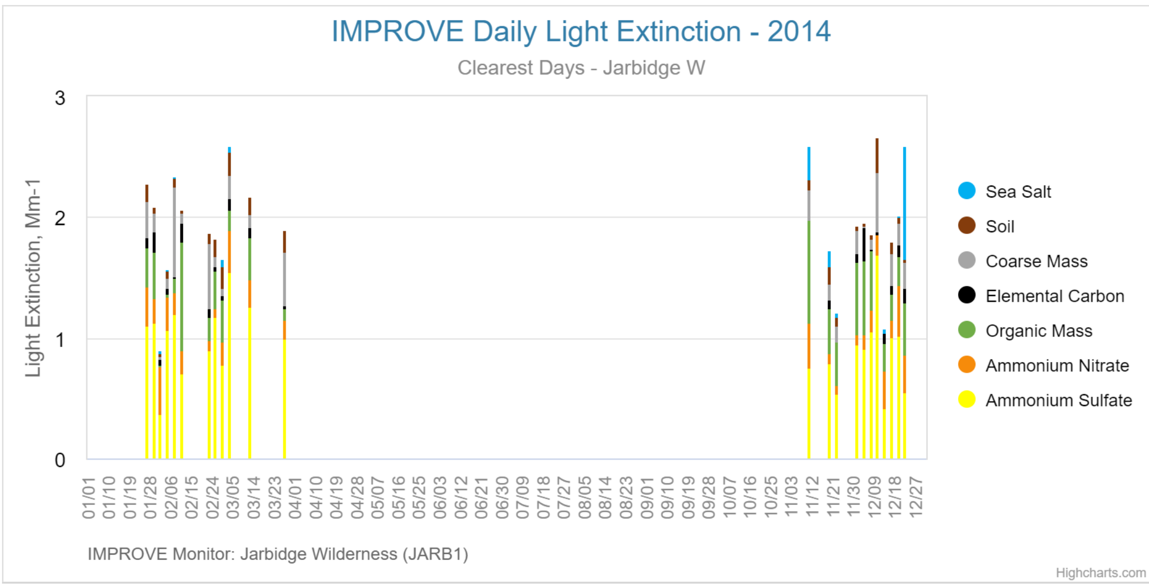
MONTHLY DISTRIBUTION OF CLEAREST DAYS OF CURRENT PERIOD



Daily reconstructed light extinction for the 20 percent clearest days of the current period at JARB1 is presented in Figure 2-23 and shows OMC and/or SO_4 are generally the largest components of visibility impairment on the clearest days at the Jarbidge Wilderness Area. NO_3, CM, and Sea Salt are significant components for a handful of days.

FIGURE 2-23

DAILY RECONSTRUCTED LIGHT EXTINCTION FOR
CLEAREST DAYS OF CURRENT PERIOD



2.7.2 Comparison of Extinction for Clearest and Most impaired Days

Baseline Conditions

Figure 2-24 compares the average baseline extinction for the 20 percent most impaired days with the 20 percent clearest days from the JARB1 monitor. All components of extinction are less on the clearest days, but significant reductions in CM and OMC extinction result in the majority of the visibility improvement on the clearest days, confirming the significant role of natural emissions in visibility impairment at the Jarbidge Wilderness Area. There are large reductions in SO_4 as well, indicating that SO_4 is the primary anthropogenic pollutant contributing to visibility impairment at Jarbidge Wilderness Area.

Table 2-5 presents the monitored contributions to reconstructed light extinction by species for the most impaired and clearest days of the baseline period based on data from the WRAP's Technical Support System. For the most impaired days, SO_4, OMC, and CM, on average, contribute more than three quarters of the extinction. Sources of OMC and CM emissions are predominantly natural and uncontrollable, as are SOIL and EC emission sources. NO_3 contributes less than 10 percent to reconstructed extinction for the most impaired and clearest days. Sources of SO_2 and NO_x emissions are largely anthropogenic and controllable.

FIGURE 2-24

COMPARISON OF BASELINE EXTINCTION FOR
MOST IMPAIRED AND CLEAREST DAYS OF BASELINE PERIOD

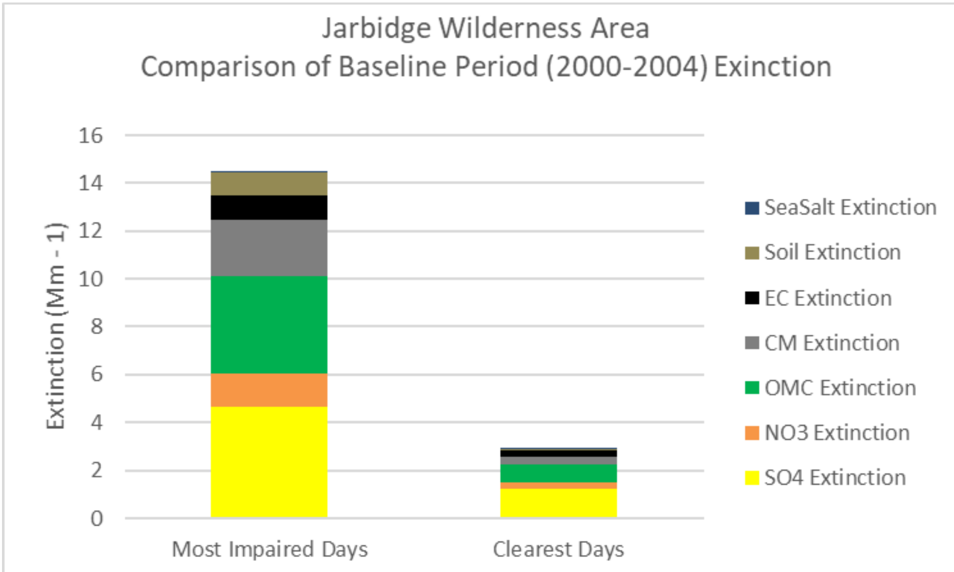


TABLE 2-5

MONITORED CONTRIBUTIONS TO ANNUAL RECONSTRUCTED
EXTINCTION BY SPECIES FOR BASELINE PERIOD

Year	SO_4 Extinction	NO_3 Extinction	OMC Extinction	EC Extinction	Soil Extinction	CM Extinction	SeaSalt Extinction
20 Percent Most Impaired Days							
2001	36.0%	9.7%	22.7%	6.7%	7.8%	17.0%	0.1%
2002	27.9%	15.0%	26.9%	7.4%	6.7%	15.8%	0.3%
2003	25.2%	5.4%	37.7%	8.1%	5.1%	18.4%	0.0%
2004	41.0%	7.8%	23.5%	6.1%	6.8%	14.3%	0.5%
Average	**32.2%**	**9.4%**	**28.1%**	**7.1%**	**6.5%**	**16.4%**	**0.2%**
20 Percent Clearest Days							
2001	45.8%	12.3%	22.8%	8.6%	3.1%	7.1%	0.2%
2002	40.3%	8.2%	25.9%	9.2%	3.0%	12.0%	1.5%
2003	34.3%	9.2%	31.5%	10.9%	2.8%	9.6%	1.7%
2004	43.2%	9.4%	24.7%	8.8%	2.4%	8.4%	3.2%
Average	**41.0%**	**9.9%**	**26.1%**	**9.4%**	**2.8%**	**9.2%**	**1.6%**

Current Conditions

Figure 2-25 compares the average current extinction for the 20 percent most impaired days with the 20 percent clearest days from the JARB1 monitor. All components of extinction are less on the clearest days, but significant reductions in CM and OMC extinction result in the majority of the visibility improvement on the clearest days, confirming the significant role of natural emissions in visibility impairment at the Jarbidge Wilderness Area. There are large reductions in SO_4 as well, further supporting that SO_4 is the primary anthropogenic pollutant contributing to visibility impairment at Jarbidge Wilderness Area.

Table 2-6 presents the monitored contributions to reconstructed light extinction by species for the most impaired and clearest days of the baseline period based on data from the WRAP's Technical Support System. For the most impaired days, SO_4, OMC, and CM, on average, contribute more than three quarters of the extinction. Sources of OMC and CM emissions are predominantly natural and uncontrollable, as are SOIL and EC emission sources. NO_3 contributes less than 10 percent to reconstructed extinction for the most impaired and clearest days. Sources of SO_2 and NO_x emissions are largely anthropogenic and controllable.

Although extinction contributions for both the most impaired and clearest days during the baseline and current periods share similar trends and profiles, note that there has been a decrease in total light extinction for both the most impaired and clearest days from the baseline period to the current period. Light extinction during the 20 percent most impaired days decreased by 2 Mm^{-1} and 1 Mm^{-1} during the 20 percent clearest days.

FIGURE 2-25

COMPARISON OF CURRENT EXTINCTION FOR
MOST IMPAIRED AND CLEAREST DAYS OF CURRENT PERIOD

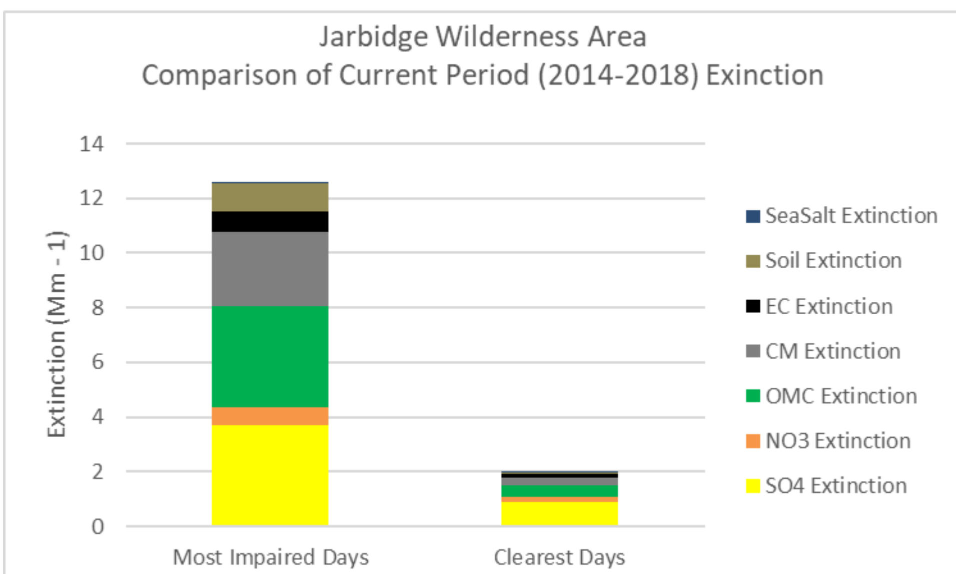


TABLE 2-6

MONITORED CONTRIBUTIONS TO ANNUAL RECONSTRUCTED
EXTINCTION BY SPECIES FOR CURRENT PERIOD

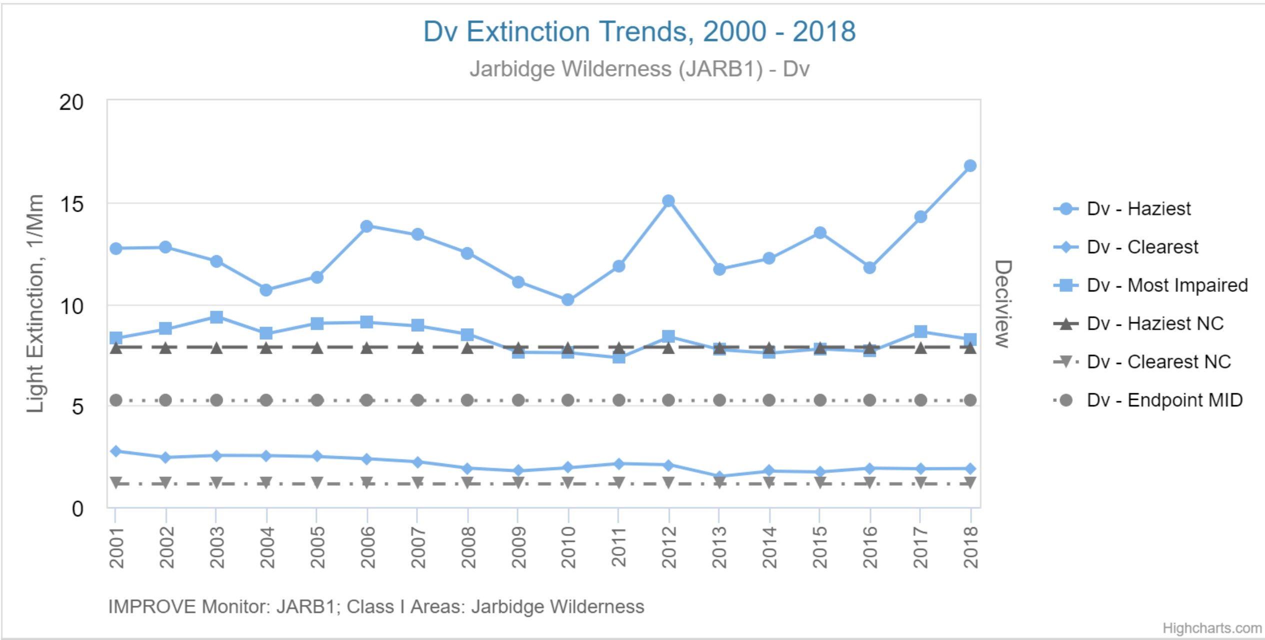
Year	SO_4 Extinction	NO_3 Extinction	OMC Extinction	EC Extinction	Soil Extinction	CM Extinction	SeaSalt Extinction
20 Percent Most Impaired Days							
2014	42.1%	8.1%	19.4%	5.0%	9.0%	16.1%	0.3%
2015	35.6%	5.7%	27.4%	5.6%	8.2%	17.2%	0.4%
2016	28.1%	4.1%	29.2%	5.2%	8.9%	24.2%	0.3%
2017	23.6%	4.0%	36.7%	6.3%	6.8%	22.4%	0.2%
2018	19.3%	4.5%	32.2%	6.4%	9.8%	27.5%	0.3%
Average	**29.3%**	**5.2%**	**29.3%**	**5.7%**	**8.5%**	**21.6%**	**0.3%**
20 Percent Clearest Days							
2014	49.1%	11.0%	17.1%	3.8%	4.8%	10.7%	3.5%
2015	49.8%	9.4%	16.9%	3.7%	4.0%	14.0%	2.1%
2016	45.0%	14.6%	15.7%	5.4%	4.3%	13.3%	1.7%
2017	36.5%	9.8%	29.0%	8.0%	3.3%	11.8%	1.7%
2018	35.2%	8.7%	26.4%	9.3%	4.0%	13.7%	2.6%
Average	**42.9%**	**10.7%**	**21.1%**	**6.1%**	**4.1%**	**12.7%**	**2.3%**

2.7.3 Aerosol Pollutant Trends

Figure 2-26 presents the annual monitored light extinction in deciviews for the 20 percent haziest, most impaired, and clearest days and corresponding trend lines for natural conditions goals. The long-term annual extinction trend for the 20 percent most impaired days, shown by the squares, and the 20 percent clearest days, shown by the diamonds, is essentially flat, although there are some annual variations. Both also show a slight downward trend indicating a gradual improvement in visibility impairment. The long-term annual extinction trend for the 20 percent haziest days shows significantly higher annual monitored light extinction with significant annual variations, confirming that the original “haziest” metric is sensitive to episodic events and that the new “most impaired” metric better isolates the year-round visibility impacts of anthropogenic emissions.

FIGURE 2-26

ANNUAL IMPROVE RECONSTRUCTED EXTINCTION TRENDS
FOR MOST IMPAIRED AND CLEAREST DAYS



Figures 2-27 through 2-33 show the annual extinction data on the 20 percent most impaired and clearest days for the seven haze causing pollutants from JARB1 for the years 2000 through 2018 with corresponding color-coded, long-term trend lines compared to the most impaired days natural conditions endpoint shown by grey circles. The graphs utilize valid data beginning with the baseline period and ending in the current period. from years prior to and including the baseline period. Data from 2000 did not meet the USEPA data completeness requirements (75 percent for the year and 50 percent for each quarter) and therefore does not have calculated annual concentrations.

Examination of the data provides insight into the long-term trends of haze causing pollutants at the JARB1 IMPROVE monitor. SO_4 and NO_3, considered to be emitted by mostly anthropogenic sources, have steep variations in light extinctions with slight downward trends beginning in 2013. These data suggest slight improvement, largely due to emission reductions achieved from the initial implementation period, in the long-term control of SO_2 and NO_x emissions impairing visibility at the Jarbidge Wilderness Area for the most impaired days. NO_3 extinction for the most impaired days has fallen below the natural conditions endpoint for the most impaired days in Figure 2-28. With NO_3 extinction already achieving the target goal of most impaired days natural conditions, and SO_4 extinction falling within 2 Mm^{-1} of the target goal in 2018, Nevada is well on track to reducing anthropogenic emissions, and corresponding visibility impairment contributions at Jarbidge Wilderness Area, back to natural conditions by 2064.

FIGURE 2-27

JARBIDGE WILDERNESS AREA
<u>SULFATE EXTINCTION TRENDS FOR MOST IMPAIRED DAYS</u>

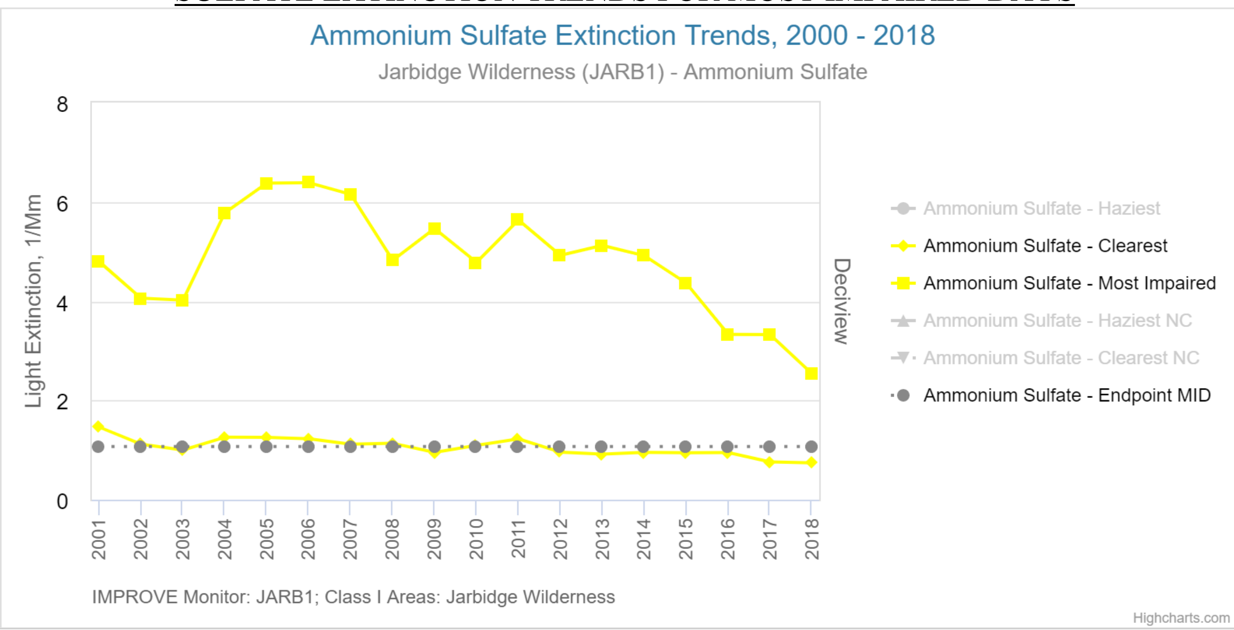
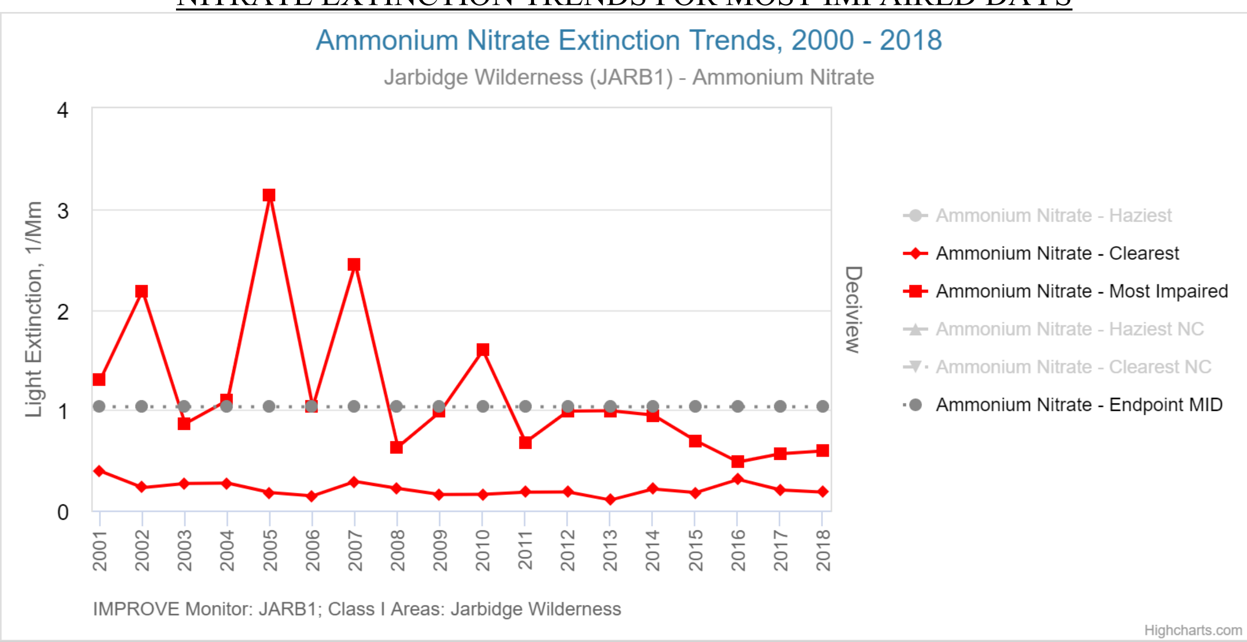


FIGURE 2-28

JARBIDGE WILDERNESS AREA
<u>NITRATE EXTINCTION TRENDS FOR MOST IMPAIRED DAYS</u>



OMC extinction, despite its large annual variation, has a well-defined, upward long-term trend beginning in 2013 and continuing through 2018, suggesting a larger role of fire emissions in regional haze with time. EC, also thought to be largely due to fire emissions, has an increasing trend over recent years beginning in 2013. This indicates that, although the new "most impaired days" metric effectively scrubs episodic fire events from the ambient air analyses, it does not accomplish this completely, and the effectiveness of the new metric appears to decrease as the intensity and occurrence of wildfires in the western U.S. continue to grow due to climate change.

FIGURE 2-29

JARBIDGE WILDERNESS AREA
ORGANIC MASS EXTINCTION TRENDS FOR MOST IMPAIRED DAYS

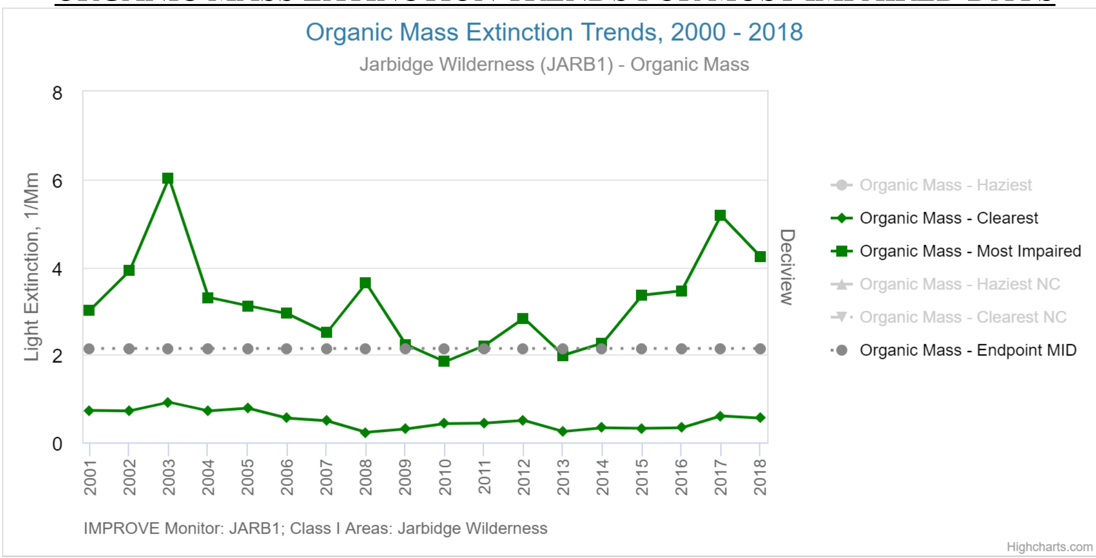
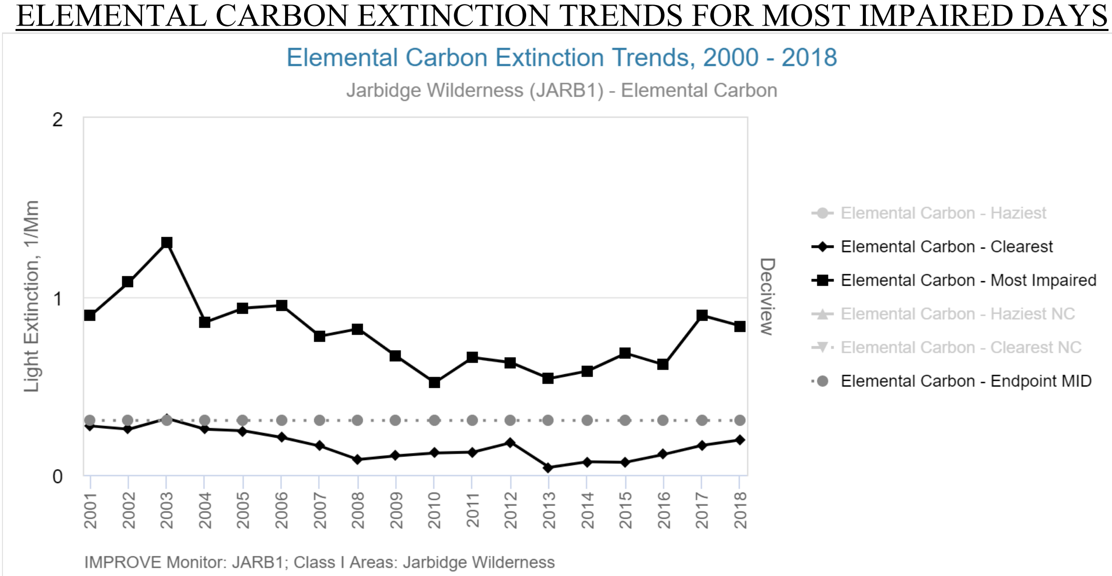


FIGURE 2-30

JARBIDGE WILDERNESS AREA
ELEMENTAL CARBON EXTINCTION TRENDS FOR MOST IMPAIRED DAYS



CM and Soil show large annual variations in light extinction, and do not show a clear downward or upward trend. CM shows a continuous increase in light extinction beginning in 2014 and may be due to an increase in fugitive dust impacts as Nevada's climate becomes drier. Although soil has an unpronounced trend, it remains steady in falling above the most impaired days natural conditions end goal. Sea salt impacts at Jarbidge Wilderness Area remain negligent, with annual light extinction never surpassing 0.25 Mm^{-1}.

FIGURE 2-31

JARBIDGE WILDERNESS AREA
COARSE MASS EXTINCTION TRENDS FOR MOST IMPAIRED DAYS

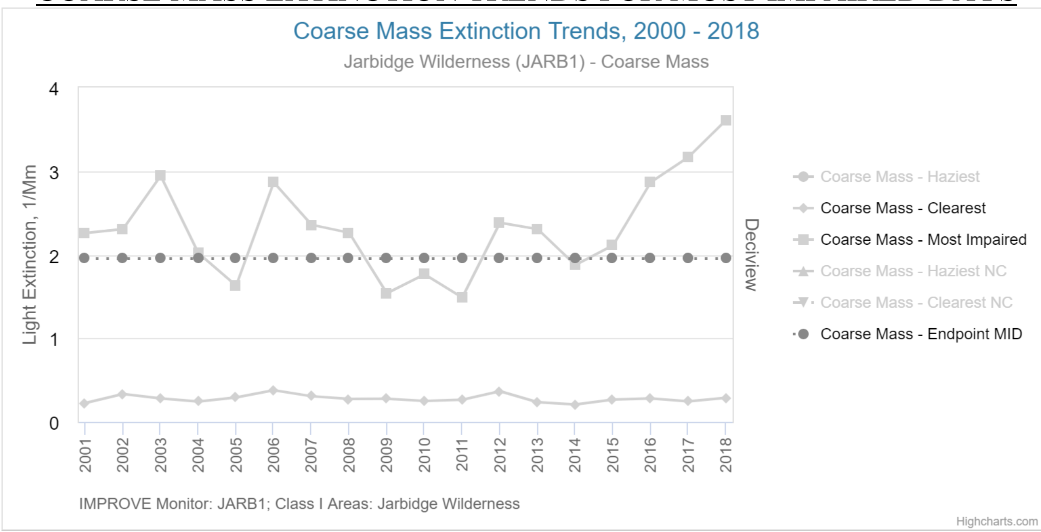


FIGURE 2-32

JARBIDGE WILDERNESS AREA
SOIL EXTINCTION TRENDS FOR MOST IMPAIRED DAYS

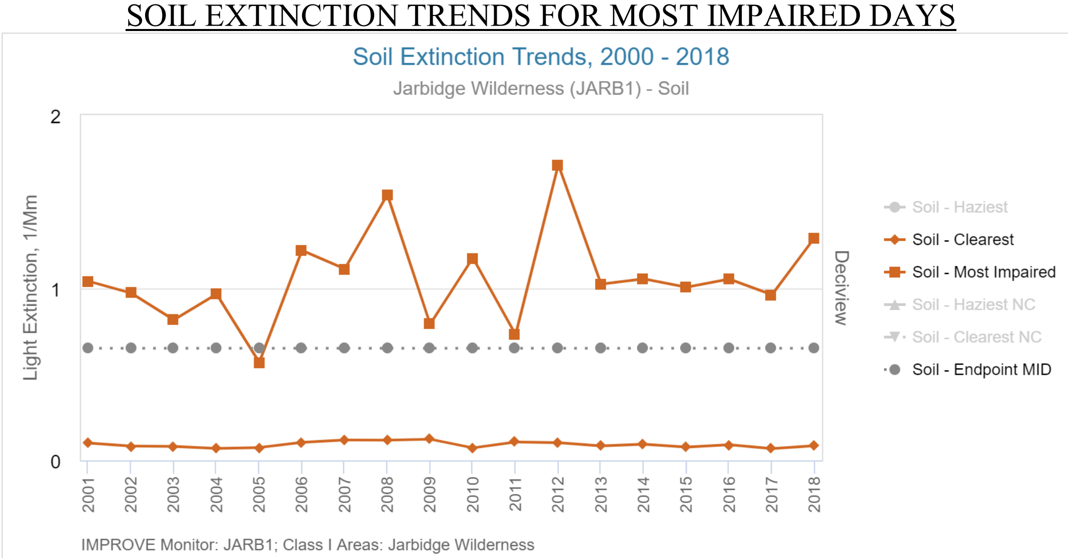
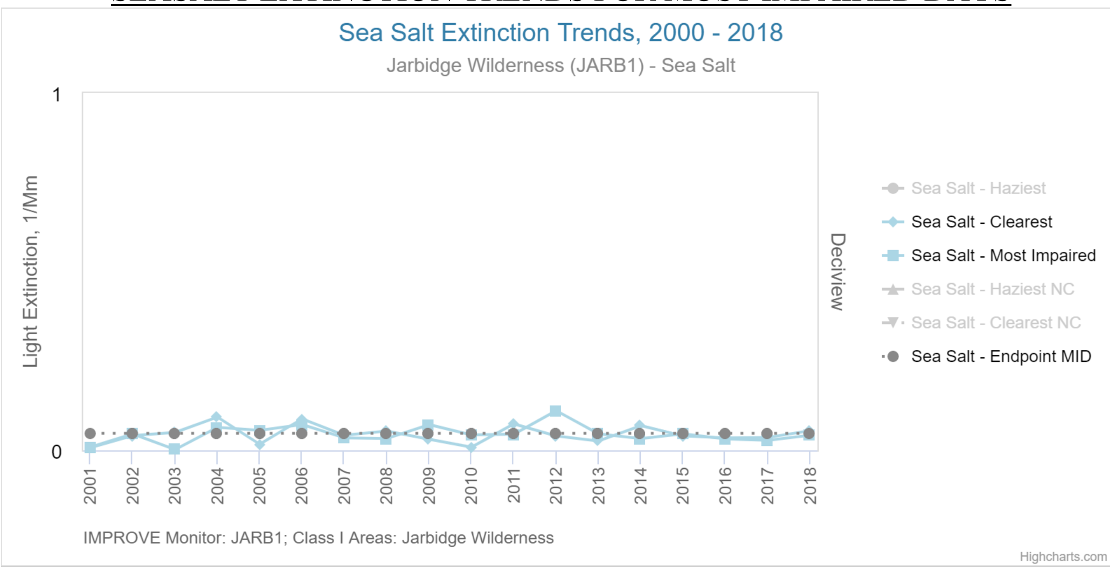


FIGURE 2-33

JARBIDGE WILDERNESS AREA
<u>SEASALT EXTINCTION TRENDS FOR MOST IMPAIRED DAYS</u>



Continued improvements in regional sulfate and nitrate levels are expected in the western states as further controls are realized on major sources as the result of BART and the implementation of other regional haze programs, as well as compliance with ozone and $PM_{2.5}$ standards. We expect these regional downward trends in SO_2 and NO_x emissions will provide continued visibility improvement.

However, the trends in OMC and SOIL are not so encouraging. The wide variations in annual concentrations on the 20 percent most impaired days may be related to alternating drought and normal precipitation conditions with corresponding increases in carbon emissions due to wildfires and increases in dust (e.g., CM and SOIL) emissions resulting from increasingly prevalent dry and dusty conditions.

NDEP has analyzed the JARB1 monitor data; identified the baseline, current, and natural visibility conditions; identified a 2028 URP value of 7.33 dv for the most impaired days; and determined SO_4, OMC, and CM extinction contribute the majority of visibility impairment on the most impaired days. These data suggest that visibility improvement due to emissions reductions of SO_2 and NO_x from anthropogenic sources may be overwhelmed by seasonally variable OMC and CM, as well as EC and SOIL, extinction contributions due to emissions from natural sources.

These data suggest control of sources of OMC, CM, and SO_2 may be the most effective means of improving visibility impairment at the Jarbidge Wilderness Area. The following chapter discusses Nevada's sources of visibility impairing pollutants.

2.8 REFERENCES

U.S. EPA 2003. Guidance for Tracking Progress under the Regional Haze Rule. EPA-454/B-03-004. September 2003.

U.S. EPA 2018. Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. EPA-454/R-18-010. December 2018.

U.S. EPA 2019. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. EPA-457/B-19-003. August 2019.

U.S. EPA 2020. Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. June 2020.

U.S. EPA 2021. Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period. July 2021.

Chapter Three - Sources of Impairment in Nevada

3.1 BACKGROUND

Federal visibility regulations at 40 CFR 51.308(f)(2)(iii) require that states document the technical basis, including 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. States are also required by 40 CFR 51.308(f)(6)(v) to provide a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area including emissions from the most recent year. The pollutants discussed in this chapter are sulfur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOC), , particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), and ammonia (NH_3). Emission scenarios that were used for this analysis were the "RepBase2" and "2028OTBa2" inventories and were obtained from the Technical Support System (TSS) (http://views.cira.colostate.edu/tssv2/Express/EmissionsTools.aspx). These inventories represent a series of refinements to previous inventories reflecting increasing levels of quality control and quality assurance by states and Western Regional Air Partnership's (WRAP) Regional Modeling Center (RMC) contractors.

This chapter presents the analysis of the sources of emissions of visibility impairing pollutants identified above. Emission inventories form one leg of the analysis stool to evaluate sources' impacts on visibility. Emission inventories were created for all critical chemicals or species known to directly or indirectly impact visual air quality. These inventories were input into air quality models to predict concentrations of pollutants over a given space and time. In support of the WRAP Regional Haze effort, RMC developed emissions inventories representing:

- 2014 Actual Baseline Emissions (2014v2)
- 2014 Through 2018 Representative Baseline Emissions (RepBase2)
- 2028 On-the-Books Base Case Emissions (2028OTBa2)
- 2028 Potential Additional Controls Emissions (PAC2)

The base and plan inventories represent a series of refinements to each inventory reflecting increasing levels of quality control and quality assurance by states and RMC contractors. The purpose of the 2014v2 inventory is to represent the actual conditions in calendar year 2014 with respect to ambient air quality and the associated sources of visibility impairing air pollutants. The purpose of the RepBase2 inventory is to represent baseline emission patterns based on average, or "typical", conditions. It provides a basis for comparison with the 2028 projected emissions, as well as for gauging reasonable progress with respect to future year visibility.

2028OTBa2 represents conditions in future year 2028 with respect to sources of criteria and particulate matter air pollutants, taking into consideration growth and controls. The 2028OTBa2 emissions scenario includes reductions due to "on-the-way" and "on-the-books" controls, consent decree reductions, SIP control measures, and other relevant regulations that have gone into effect since 2014 or will go into effect before the end of 2028. Modeling results based on the 2028OTBa2 emission inventory are used to define the future year ambient air quality and visibility metrics.

The PAC2 inventory was created to establish the most representative source-specific emissions projections data as the basis for preparing regional haze plans. The PAC2 inventory includes reductions to NO_x and SO_2 based on presumptive add-on controls. Note that emission reductions assumed in the PAC2 inventory are preliminary results to the four-factor analyses that had not yet been finalized. Final controls determined necessary to make reasonable progress may differ from what was assumed in PAC2, as this model scenario was solely used as a reference to states in gauging potential visibility improvement from potential controls

Dispersion modeling predicts daily atmospheric concentrations of pollutants for the baseline year, and these modeled results are compared to monitored data taken from the Interagency Monitoring of Protected Visual Environments (IMPROVE) network. A second inventory is then created to predict emissions in 2028 based on expected controls, growth or other factors.

3.2 SOURCES OF VISIBILITY IMPAIRMENT

Emissions have been categorized by pollutant among the 13 continental WESTAR-WRAP states for 14 anthropogenic source sectors and 5 natural source sectors, as outlined in Table 3-1.

TABLE 3-1

SUMMARY OF POLLUTANTS, SOURCE SECTORS, AND SOURCE AREAS

Pollutants	Source Sectors	Source Areas
Sulfur dioxide (SO_2)	Electric Generating Units (EGU)	Arizona (AZ)
Nitrogen oxides (NO_x)	Oil & Gas – Point	California (CA)
Volatile organic carbon (VOC)	Industrial and Non-EGU Point	Colorado (CO)
	Oil & Gas – Non-point	Idaho (ID)
Particulate matter less than 10 microns (PM_{10})	Residential Wood Combustion	Montana (MT)
Particulate matter less than 2.5 microns ($PM_{2.5}$)	Fugitive Dust	Nevada (NV)
Ammonia (NH_3)	Agriculture	New Mexico (NM)
	Remaining Non-Point	North Dakota (ND)
	On-Road Mobile	Oregon (OR)
	Non-road Mobile	South Dakota (SD)
	Rail	Utah (UT)
	Commercial Marine	Washington (WA)
	Agricultural Fire	Wyoming (WY)
	Wildland Prescribed Fire	
	Wildfire	
	Biogenic	
	Lightning NO_x	
	Oceanic Sea Salt	
	Windblown	

Natural fire sources, biogenic sources and windblown dust are shown in *italics* to denote that they are natural sources; all other sources are anthropogenic.

3.2.1 Natural Visibility Conditions

The RHR defines visibility impairment as "any humanly perceptible difference due to air pollution from anthropogenic sources between actual visibility and natural visibility on one or more days," meaning, that natural visibility is the difference between actual visibility conditions and visibility impairment. Natural events (e.g. natural fire, biogenic emissions, and windblown dust) introduce pollutants that contribute to natural visibility conditions. In Nevada, natural sources are important contributors of NO_x, PM_{10}, $PM_{2.5}$, and VOC, however, these contributions to natural visibility conditions are not required to be reduced by the RHR, as natural visibility conditions are the national visibility goal.

3.2.2 Anthropogenic Sources of Visibility Impairment

Anthropogenic or human-caused sources of visibility impairment include anything directly attributable to human-caused activities that produce emissions of visibility-impairing pollutants. Some examples include point sources, area sources, mobile sources, oil and gas sources, road dust, fugitive dust and anthropogenic fires. Generally anthropogenic emissions include not only those that are generated or originated within the boundaries of the United States, but also international emissions that are generated outside of the United States but transported into the region. Some examples include emissions from Mexico, Canada and maritime shipping emissions in the Pacific Ocean. Note that Mexican and Canadian emission inventories include both anthropogenic and natural emissions.

Although international anthropogenic sources contribute to visibility impairment, they cannot be regulated, controlled or prevented by Nevada and, as with natural emissions, are beyond the scope of this planning document. Any reductions in international emissions would likely fall under the purview of the USEPA administrator. Table 3-2 shows that in Nevada, anthropogenic sources are important contributors of all pollutants except VOCs, which are largely contributed by natural sources at a much higher degree than the rest of the contributors. Although anthropogenic contributions typically have a higher percentage, total emissions show a higher contribution from natural sources because of VOC contributions. The source of data summarized in Table 3-2 is shown in more detail in Section 3.8.

TABLE 3-2

SUMMARY OF ANTHROPOGENIC AND NATURAL
EMISSION SOURCES IN NEVADA

Pollutant	2014 Anthropogenic Sources	2014 Natural Sources	2028 Anthropogenic Sources	2028 Natural Sources
SO_2	94%	6%	92%	8%
NO_x	53%	47%	34%	66%
VOC	6%	94%	5%	95%
PM_{10}	86%	14%	86%	14%
NH_3	93%	7%	93%	7%
$PM_{2.5}$	71%	29%	70%	30%
Total emissions:	33%	67%	27%	73%

3.3 DEVELOPMENT OF THE 2014 AND 2028 EMISSION INVENTORIES

In general, emission inputs were prepared by individual states and tribes for point, area and most dust emissions categories. With input and review by states, tribes and Federal Land Managers, WRAP forums and workgroups prepared consistent and comparable WRAP region emissions data for the mobile, fire, ammonia, area source oil and gas, eastern Pacific offshore shipping, some dust and biogenic emissions categories. The WRAP Emissions Inventory and Modeling Protocol Subcommittee gathered the latest, best and most representative emissions estimates at the time from the CENWRAP, Eastern U.S., Canada and Mexico regions in executing the sequence of modeling simulations discussed below. Boundary conditions reaching North America from the rest of the world were jointly prepared by all five Regional Planning Organizations (RPO)s from the GEOS-Chem global model.

The original inventories evolved from states' actual emissions data submitted to USEPA for the 2014 National Emission Inventory (NEI). The 2014 NEI consisted of a complete set of point, non-point and mobile data that had been submitted to EPA. The 2014v2 emission inventory was chosen to provide a baseline against which reductions in visibility-impairing pollutants could be measured over time. Emissions data recorded between 2014 and 2018 substituted data from the 2014 NEI to develop the Representative Baseline (RepBase2). The 2028 emission inventory was developed because 2028 is the year the second regional haze SIP planning period ends. Historical development of the different versions of the emission inventories that were developed for the 2014v2, RepBase2, 2028OTBa2 and PAC2 inventories is described in detail in Chapter One. For this chapter's discussion, the 2014 emission inventory refers to RepBase2 and the 2028 emission inventory refers to 2028OTBa2.

3.4 POINT SOURCE EMISSION INVENTORY

Point sources are identified by point locations, typically because they are regulated, and their locations are available in regulatory reports. Point sources can be further subdivided into EGU sources and non-EGU sources, particularly in criteria inventories in which EGUs are a primary source of NO_x and SO_2.

Compared to the surrounding continental WRAP states, Nevada generally contributes less emissions from the point source sector than most other states. Point source contributions for NO_x, SO_2, PM_{10}, $PM_{2.5}$, VOC, , and NH_3 state-wide emissions were compared among the western states. Point sources were divided into Oil & Gas Point, Industrial and Non-EGU Point, and EGU Point (indicated as maroon, purple, and green, respectively) and compared between the RepBase2 scenario and 2028OTBa2 scenario for each state.

Figure 3-1 shows NO_x emissions contributed by point sources among the western states. Nevada, with roughly 12,000 tpy in state-wide NO_x emissions, has the third lowest annual tonnage. These NO_x emissions are not contributed by Oil and Gas point sources but from EGU and Non-EGU point sources. Roughly two thirds of total NO_x emissions in the point source sector are contributed by Non-EGU/Industrial sources, and one third is contributed by EGUs. NO_x emissions projected in 2028 are similar to the representative baseline, with a slight decrease among EGUs.

FIGURE 3-1

POINT SOURCE NOx EMISSIONS PROFILE IN NEVADA COMPARED TO WESTERN STATES

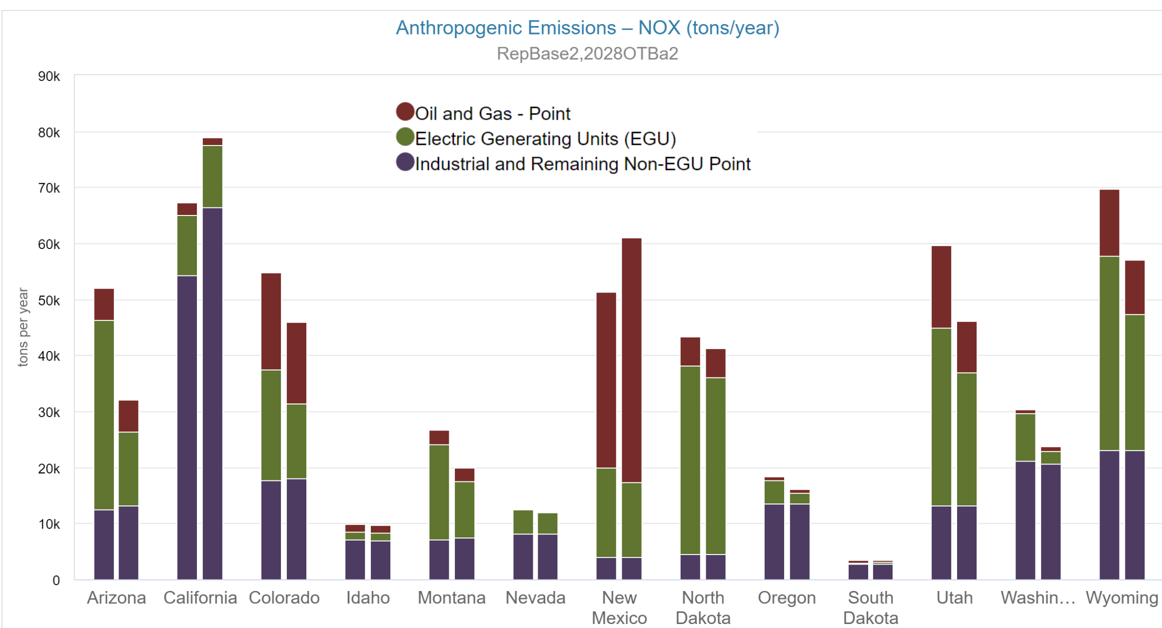


Figure 3-2 shows SO_2 emissions contributed by point sources among the western states. Nevada, with roughly 7,000 tpy in state-wide SO_2 emissions, has the third lowest annual tonnage. These SO_2 emissions are not contributed by Oil and Gas point sources but from EGU and Non-EGU point sources. Roughly three quarters of total SO_2 emissions in the point source sector are contributed by EGU sources, and one quarter is contributed by Non-EGUs/Industrial. A decrease in 2,500 tpy of SO_2 emissions are projected for EGUs in 2028.

FIGURE 3-2

POINT SOURCE SO_2 EMISSIONS PROFILE IN NEVADA COMPARED
TO WESTERN STATES

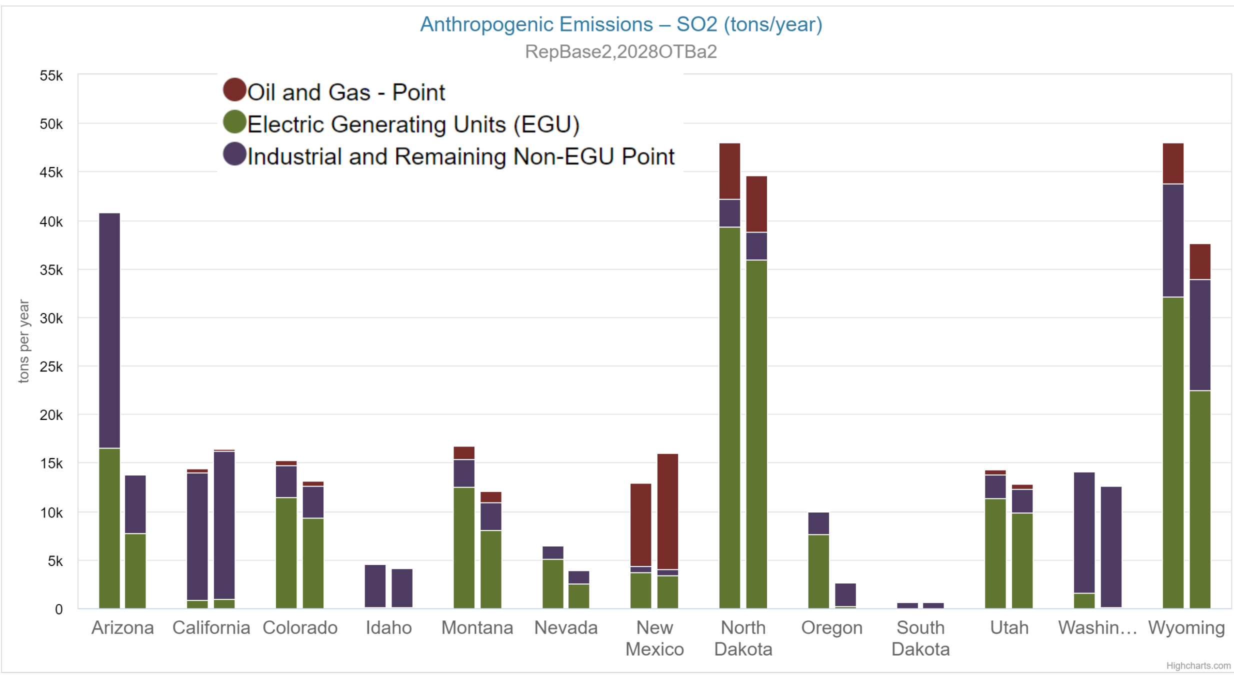


Figure 3-3 shows PM_{10} emissions contributed by point sources among the western states. Nevada, with roughly 4,000 tpy in state-wide PM_{10} emissions, has the third lowest annual tonnage. These PM_{10} emissions are not contributed by Oil and Gas point sources but from EGU and Non-EGU point sources. Roughly three quarters of total PM_{10} emissions in the point source sector are contributed by Non-EGU/Industrial sources, and one quarter is contributed by EGUs. A slight decrease in PM_{10} emissions are projected in 2028.

Figure 3-4 shows $PM_{2.5}$ emissions contributed by point sources among the western states. Nevada, with roughly 2,200 tpy in state-wide $PM_{2.5}$ emissions, has the third lowest annual tonnage. These $PM_{2.5}$ emissions are not contributed by Oil and Gas point sources but from EGU and Non-EGU point sources. $PM_{2.5}$ emissions are almost shared equally between EGU and Non-EGU point sources. There is no change in emissions from the representative baseline to 2028.

FIGURE 3-3

POINT SOURCE PM_{10} EMISSIONS PROFILE IN NEVADA COMPARED TO WESTERN STATES

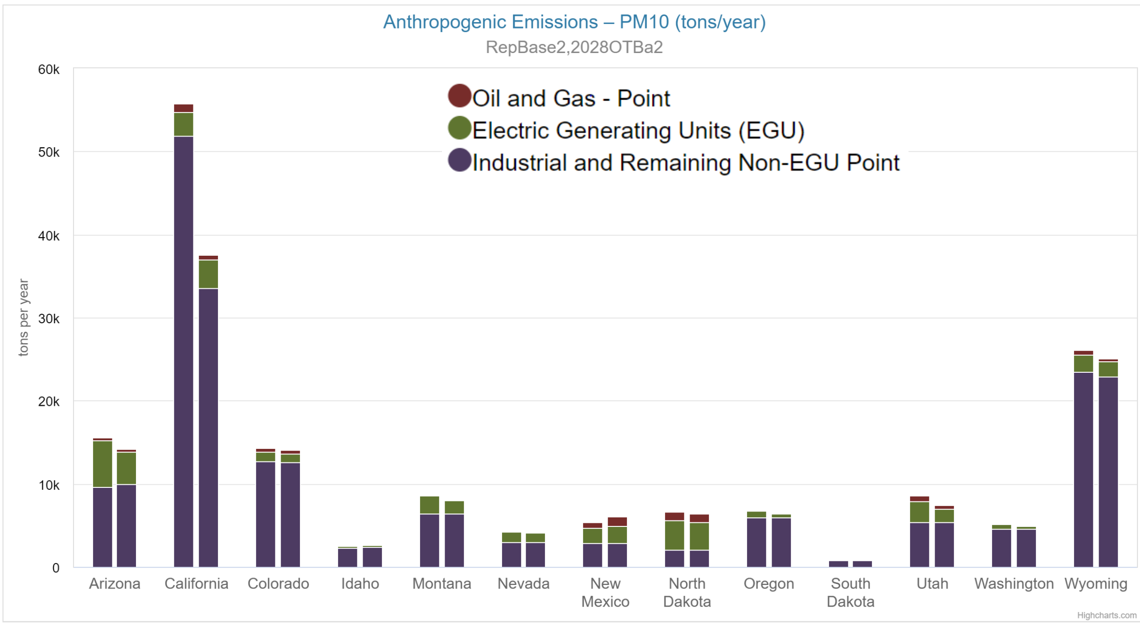


FIGURE 3-4

POINT SOURCE $PM_{2.5}$ EMISSIONS PROFILE IN NEVADA COMPARED TO WESTERN STATES

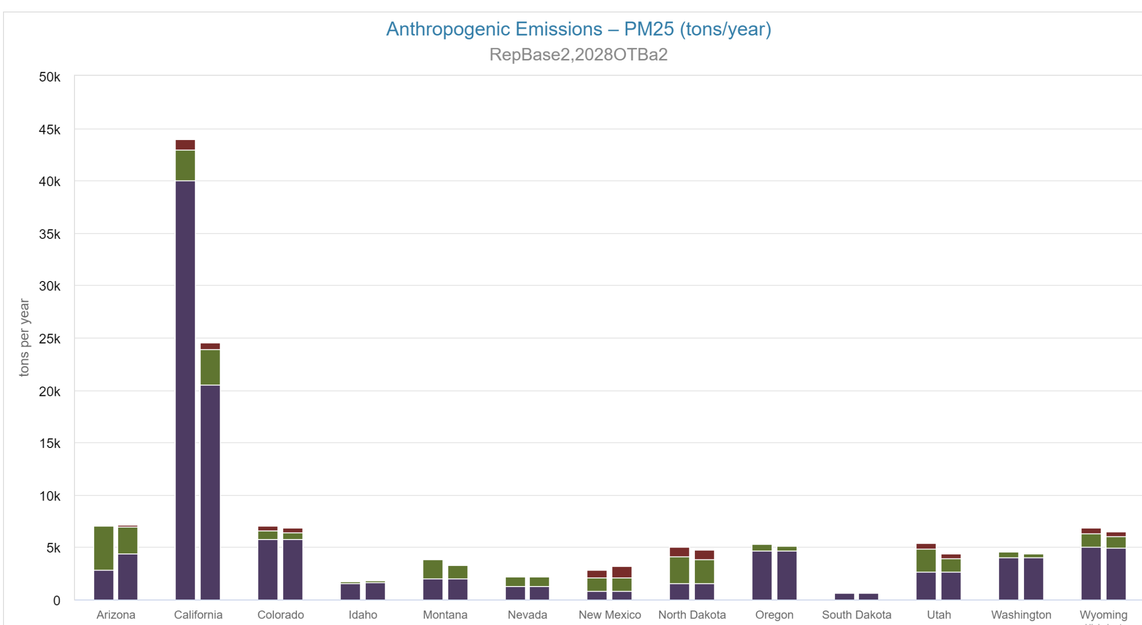


Figure 3-5 shows VOC emissions contributed by point sources among the western states. Nevada, with roughly 2,400 tpy in state-wide VOC emissions, has the third lowest annual VOC tonnage. The vast majority of VOC emissions are contributed by the Non-EGU/Industrial point sources. There is no change in emissions from the representative baseline to 2028.

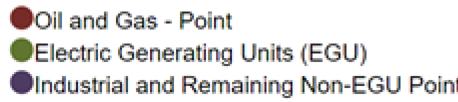


FIGURE 3-5

POINT SOURCE VOC EMISSIONS PROFILE IN NEVADA COMPARED TO WESTERN STATES

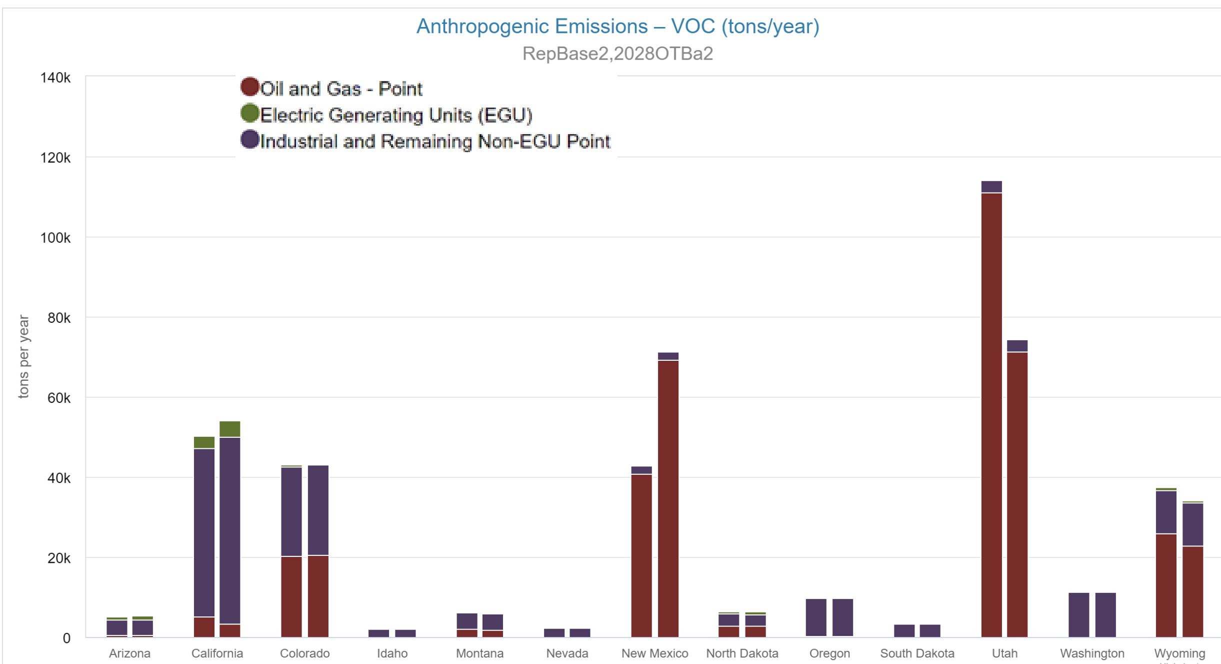
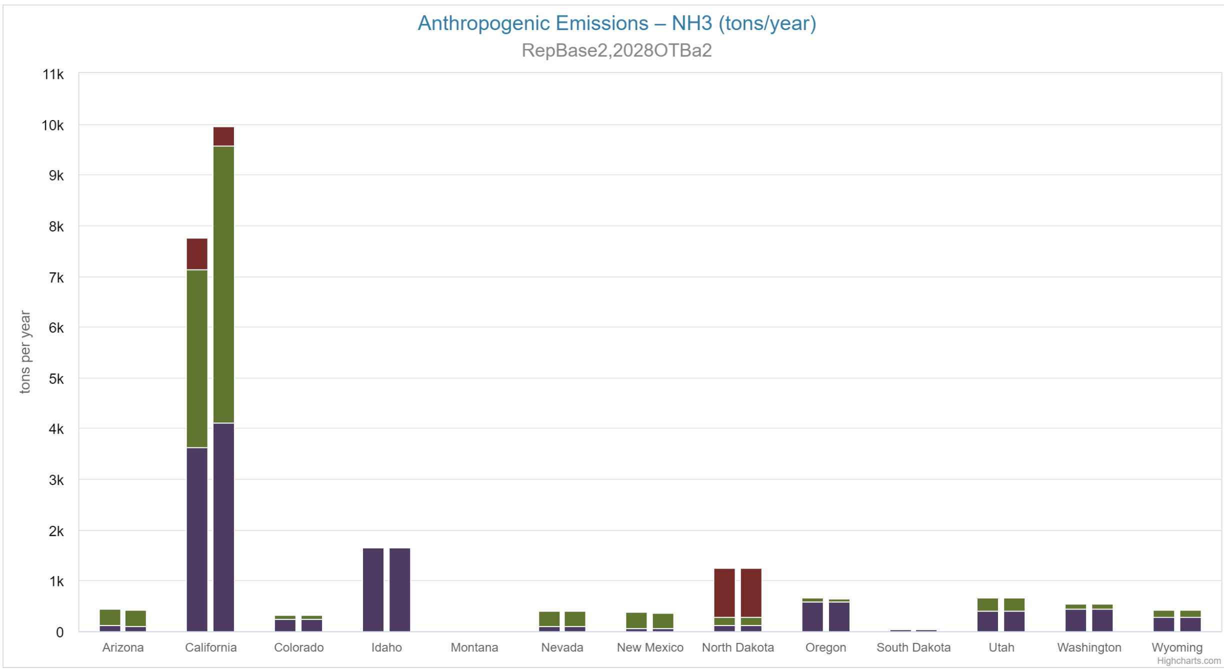


Figure 3-6 shows NH_3 emissions contributed by point sources among the western states. Nevada, with roughly 400 tpy in state-wide NH_3 emissions, is one of many states that are not significant contributors of NH_3 emission from point sources. NH_3 emissions are not contributed by Oil and Gas point sources but largely from Non-EGU point sources, accounting for three quarters of total emissions. There is no change in emissions from the representative baseline to 2028.

FIGURE 3-6

POINT SOURCE NH_3 EMISSIONS PROFILE IN NEVADA COMPARED
TO WESTERN STATES



3.5 FIRE EMISSION INVENTORY

The Fire and Smoke Workgroup (FSWG) of the WRAP and its contractor, Air Sciences Inc., prepared a 2014 base year, representative baseline, and 2028 future year fire emission inventories. A document was produced April 2020 describing these inventories. http://www.wrapair2.org/pdf/fswg_rhp_fire-ei_final_report_20200519_FINAL.PDF. Inventory years 2014 through 2018 were used to estimate the emissions for the representative baseline period.

For the fire inventories in the 2014 base year inventory, EPA's 2014 Wildland Fire EI, version 2, was used. Adjustments submitted by states were incorporated into the fire inventory, however, Nevada did not make any adjustments. Other alterations to the 2014 base year fire inventory were made to incorporate information from the NOAA's Hazard Mapping System (HMS) and process misclassified fire events.

A representative single-year fire emission inventory to be used for regional haze planning was developed based on the typical activity observed during the 2014 through 2018 baseline years. This representative fire inventory further accounted for wildfire activity data, prescribed and agricultural fire activity, and calculated daily emissions for each fire event during the representative period.

Two future fire scenarios for the year 2028 were developed based on predictions of future conditions, both from a land management and climate change perspective. Each scenario scaled acres burned at the individual event level for one fire type. Methods of scaling differed for wildfire and prescribed fire; agricultural fires were left unchanged in both scenarios. Other aspects of future conditions, such as fuel loading or average consumptions, were not considered.

3.6 AREA SOURCE INVENTORY

The area source emission inventory was primarily taken from the 2014 NEIv2, using nonpoint source data that are provided by state, local, and tribal agencies, and for certain sectors and/or pollutants, they are supplemented with data from the EPA. Area source emissions typically rely on population and economic growth factors.

3.7 OVERVIEW OF EMISSION INVENTORY SYSTEM - TSS

The WRAP developed the Technical Support System version 2 (TSS) as an Internet access portal to all the data and analysis associated with the development of the technical foundations of regional haze plans across the Western US. The TSS provides state, county and grid cell level emissions information for typical criteria pollutants such as SO_2 and NO_x and other secondary particulate forming pollutants such as VOC and NH_3. Nineteen different emission inventories were developed comprising the following source categories: point, area, on-road mobile, off-road mobile, oil and gas, anthropogenic fire, natural fire, biogenic, road dust, fugitive dust and windblown dust. More detailed information on the emission inventory information can be found on the WRAP TSS website at the following link: http://views.cira.colostate.edu/tssv2/Express/EmissionsTools.aspx.

3.8 EMISSIONS IN NEVADA

The pollutants inventoried by the WRAP include SO_2, NO_x, VOC, CO, $PM_{2.5}$, PM_{10}, and NH_3. An inventory was developed for the 2014 baseline year, representative baseline period, and projections of future emissions for 2028 for modeling purposes. 2017 NEI emissions are also provided to confirm there are no significant differences between the emissions inventories developed and the most recent NEI to satisfy 40 CFR 51.308 (f)(2)(iii). Nevada will provide updates to the WRAP on this inventory on a periodic basis. For purposes of the Regional Haze SIP, the WRAP developed emission inventories for each state with input from participating stakeholders. Note that these emission inventories were developed solely to supplement certain model scenarios for baseline and future visibility conditions at Class I areas (presented in Chapter Four). These inventories do not include the final, actual reductions achieved as a result of additional controls required in the SIP's reasonable progress control analyses (Chapter Five). The difference between reductions assumed in the following inventories and actual reductions achieved are quantified and corrected in the final reasonable progress goals, or 2028 visibility projections outlined in Chapter Six.

The process for inventorying sources is similar for all species of interest. The number and types of sources is identified by various methods. For example, major stationary sources report actual annual emission rates to the USEPA national emissions database. Nevada collects annual emission data from both major and minor sources and this information is used as input into the emissions inventory. In other cases, such as mobile sources, a USEPA mobile source emissions model is used to develop emission projections. Nevada vehicle registration, vehicle mile traveled information and other vehicle data are used to tailor the mobile source data to best represent statewide and area specific emissions. Population, employment and household data are used in other parts of the emissions modeling to characterize emissions from area sources such as home heating. Thus, for each source type, emissions are calculated based on an emission rate and the amount of time the source is operating. Emission rates can be based on actual measurements from the source, or USEPA emission factors based on data from tests of similar types of emission sources. In essence, all sources go through a similar process. The number of sources is identified, emission rates are determined by measurements of those types of sources and the time of operation is determined. Annual emissions can be obtained by multiplying the emission rate times the number of hours of operation in a year.

Table 3-3 summarizes Nevada's statewide emissions for 2014 and 2028 projections in tons and are noted as either anthropogenic sources or natural sources. The percent change in tons from 2014 to 2028 is shown on a pollutant basis. Detailed discussions of each pollutant are described in the following sections. Based on the information presented in Table 3-3 the projected (2028OTBa2) sum of anthropogenic emissions for SO_2 and NO_x for all source categories is 5.8 percent of the total 2028 projected sum of emissions statewide.

The figures and tables in this section and the remainder of this chapter are based on the RepBase2 and 2028OTBa2 emission inventories, or 2014 and 2028 baseline emission inventories. Additional emission reductions achieved from reasonable progress controls are not included in the 2028 baseline emission inventory. Emission reductions achieved from reasonable progress controls are quantified and incorporated into the 2028 baseline emission inventory in Chapters Five and Six to develop Nevada's Reasonable Progress Goals for the second round.

TABLE 3-3

EMISSIONS SUMMARY TABLE FOR NEVADA FOR 2014 AND 2028:
NATURAL VS. ANTHROPOGENIC SOURCES

	2014				2028			
	Anthro-pogenic Source	Natural Source	Total Tons 2014		Anthro-pogenic Source	Natural Source	Total Tons 2028	Percent Change
SO_2	10,242	674	10,916		7,585	674	8,260	-24%
NO_x	81,651	72,847	154,498		37,487	72,847	110,334	-29%
VOC	71,339	1,067,220	1,138,559		56,675	1,067,220	1,123,894	-1%
$PM_{2.5}$	26,619	10,760	37,379		25,384	10,760	36,144	-3%
PM_{10}	147,267	22,348	169,615		137,292	22,326	159,618	-6%

NH_3	18,956	1,380	20,336		18,830	1,380	20,210	-1%
Total emissions:	345,290	1,175,207	1,520,496		283,253	1,175,207	1,458,460	-4%

3.8.1 Nevada SO_2 Emission Inventory for 2014 and 2028

Sulfur dioxide gases (SO_2) are formed when sulfur-containing fuels, such as diesel or coal, are burned, when gasoline is extracted from oil or when metals are extracted from ore. SO_2 dissolves in water vapor to form acid, and contributes to the formation of sulfate compounds [e.g. $(NH_4)_2SO_4$] when ammonia is available. These compounds can scatter the transmission of light, thus contributing to visibility reduction on a regional scale at our Class 1 Area.

Sulfur dioxide emissions produce sulfate particles in the atmosphere. Ammonium sulfate particles have a significantly greater impact on visibility than other pollutants like dust from unpaved roads due to the physical characteristics causing greater light scattering from the particles. Sulfur dioxide emissions come primarily from coal combustion at electrical generation facilities but smaller amounts come from natural gas combustion, mobile sources and even wood combustion.

A 24 percent statewide reduction in SO_2 emissions is expected by 2028 due to planned controls on existing sources; even with the growth consideration in electric generating power for the state. Point sources account for 59 percent of SO_2 emissions in the RepBase2 inventory and decrease to 47 percent for 2028OTBa2 projections as a result of on-the-books controls. These point-source reductions in SO_2 emissions are likely due to the closure of the Reid Gardner Generating Station in 2017. SO_2 emissions from mobile sources and rail are expected to decrease by 2028. Similar reductions in the west are expected from other states as BART and other planned controls take effect by 2028.

Figure 3-7 and Table 3-4 show the overall net decrease in emissions from 2014 to 2028 for SO_2 by source category. In all instances, source categories that do not have emissions contributed by the specific pollutant are not listed.

FIGURE 3-7

NEVADA SO_2 EMISSION INVENTORY – 2014 AND 2028

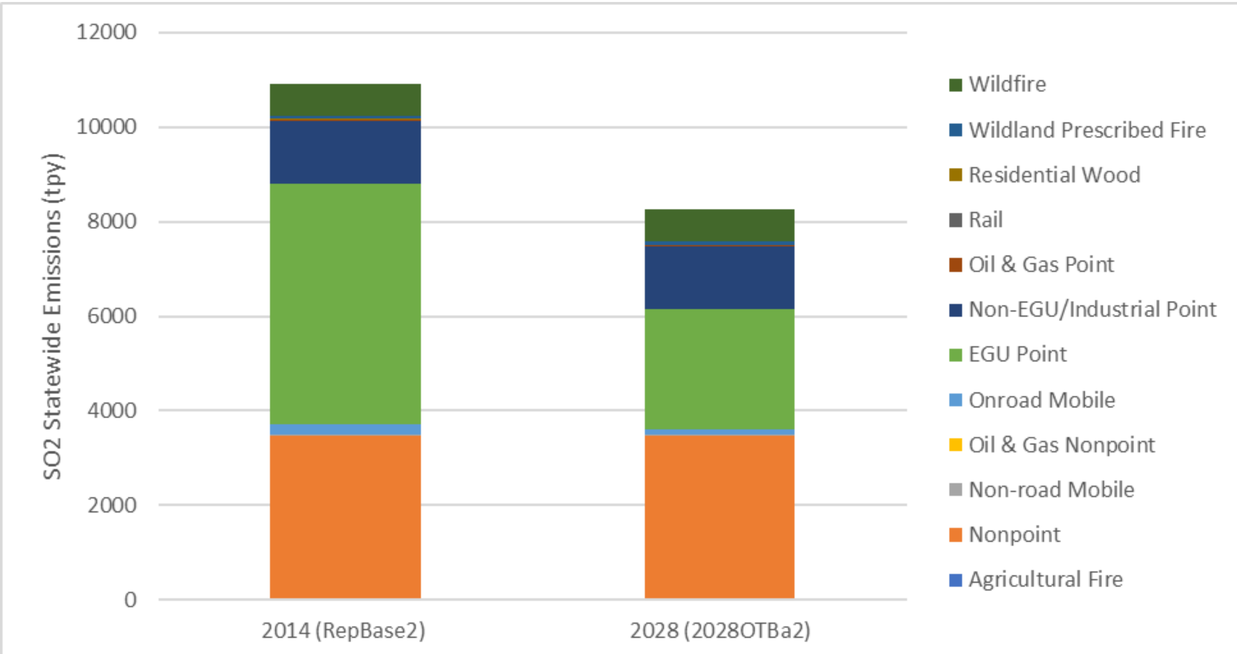


TABLE 3-4

NEVADA SO_2 EMISSIONS BY SOURCE CATEGORY FOR 2014 AND 2028

Source Category	2014 (RepBase2)	2017 (NEI)	2028 (2028OTBa2)	Net Change
Agricultural Fire	1	3	1	0%
Nonpoint	3473	247	3473	0%
Non-road Mobile	30	30	24	-20%
Oil & Gas Nonpoint	3	3	3	0%
Onroad Mobile	196	129	99	-49%
EGU Point	5109	1838	2556	-50%
Non-EGU/Industrial Point	1321	1854	1320	0%
Oil & Gas Point	16	17	16	0%
Rail	4	3	3	-25%
Residential Wood	22	24	22	0%
Wildland Prescribed Fire	67	30	67	0%
Wildfire	674	2162	674	0%
Total	10916	6340	8258	-24%

Figure 3-8, “Regional Maps of SO_2 Emissions for 2028,” shows that Nevada, with 7,640 tpy statewide, is not a significant contributor to SO_2 emissions in the West compared to other states.

FIGURE 3-8

REGIONAL MAPS OF SO_2 EMISSIONS FOR 2028

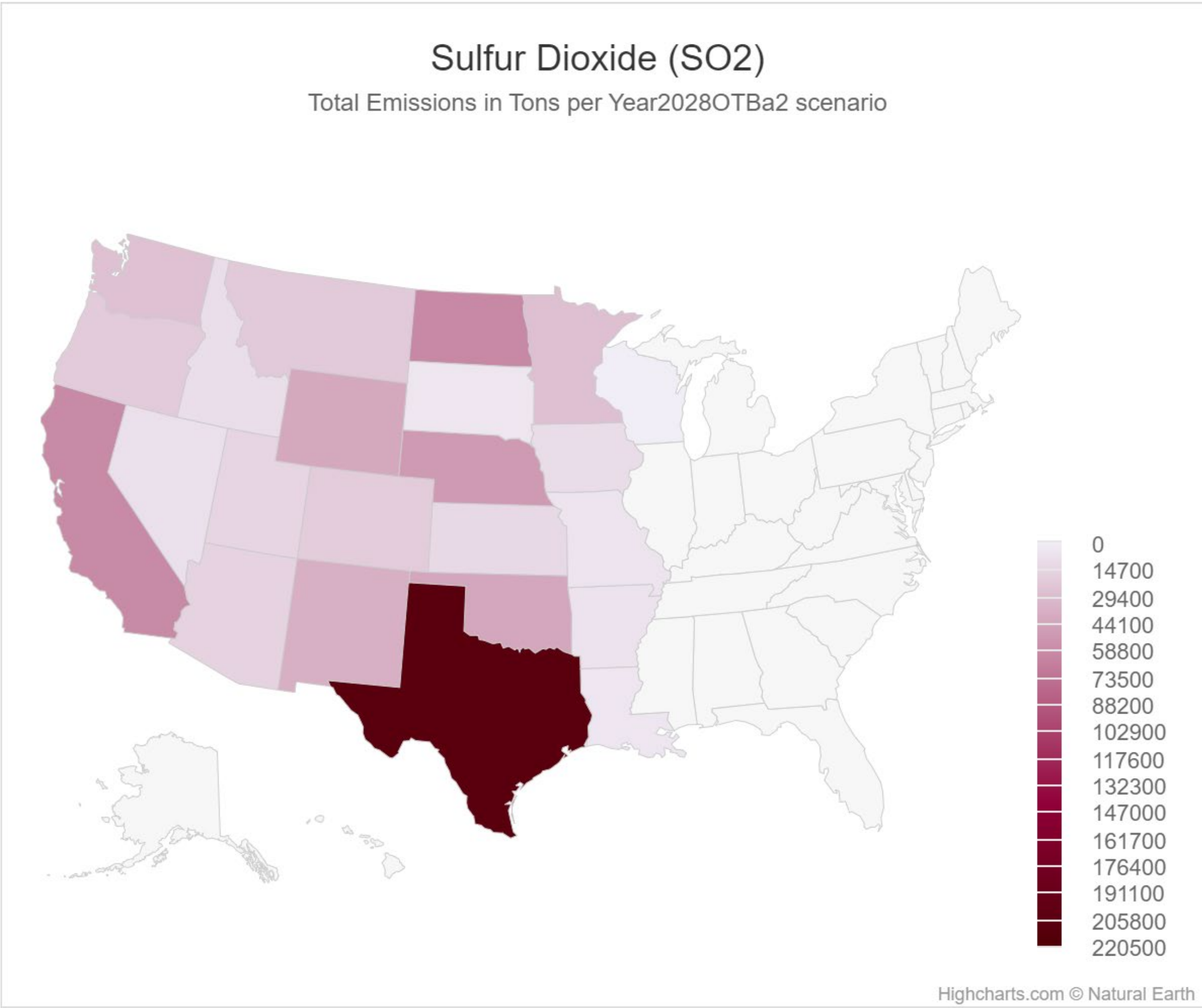
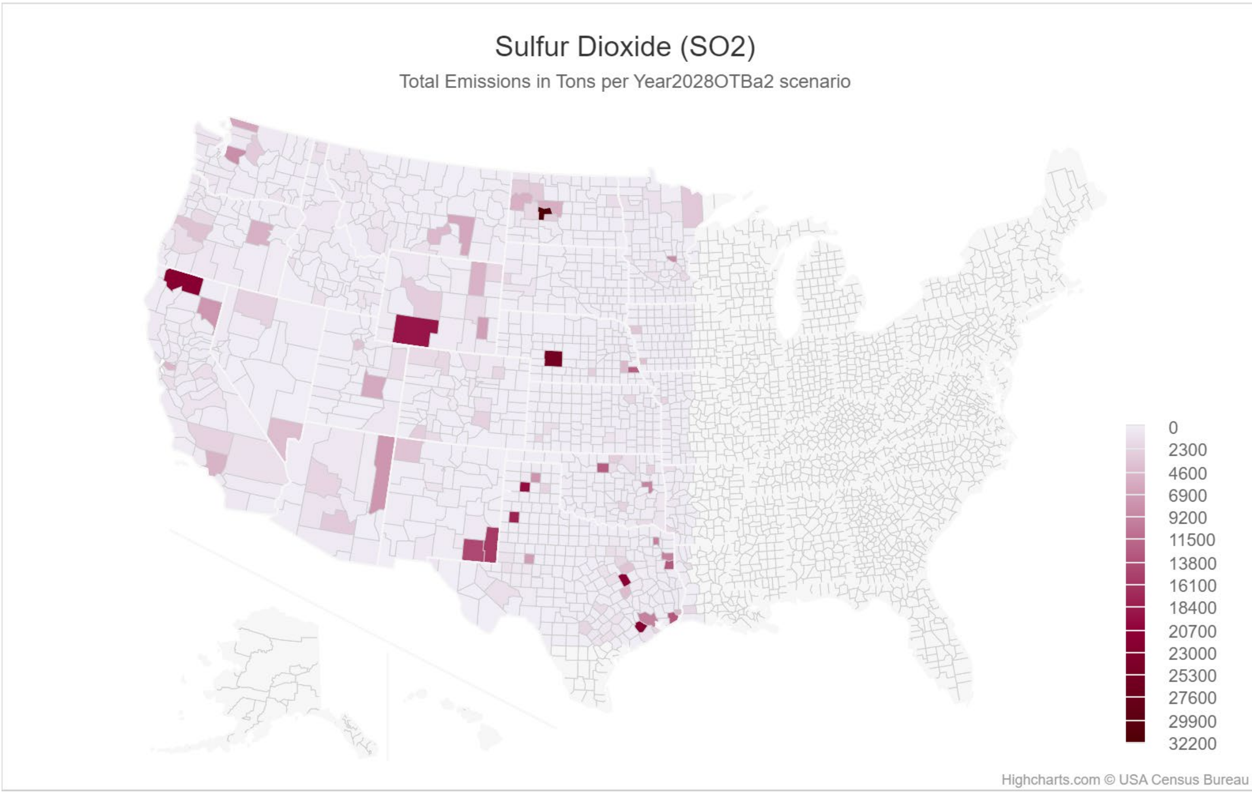


Figure 3-9, shows SO_2 emissions by county, indicating that Nevada’s counties that emit the most SO_2 emissions are Clark County, including the Las Vegas metropolitan area, and Humboldt County, where some of Nevada’s largest EGUs and industrial sources are located.

FIGURE 3-9

SULFUR DIOXIDE EMISSIONS BY COUNTY FOR 2028



3.8.2 Nevada NO_X Emission Inventory for 2014 and 2028

NO_x is generated during any combustion process where nitrogen and oxygen from the atmosphere combine together under high temperature to form nitric oxide and to a lesser degree nitrogen dioxide and in much smaller amounts, other odd oxides of nitrogen. These particles have a slightly greater impact on visibility than do sulfate particles and are four to eight times more effective at scattering light than mineral dust particles. These compounds can scatter the transmission of light, contributing to visibility reduction on a regional scale.

Point sources in Nevada contribute 8 percent of the total NO_x emissions from the RepBase2 inventory and are projected to contribute 11 percent of the overall inventory for 2028OTBa2. NOx emissions from EGU sources are expected to decrease, while NOx emissions from the Non-EGU and industrial sources remain the same.

Overall, NO_x emissions in Nevada are expected to decline by 29 percent, primarily due to significant reductions in emissions from non-road mobile sources (54 percent net decrease), on-road mobile sources (74% decrease), and rail (43% decrease) primarily due to new federal vehicle and locomotive emission standards. This equates to a 43,710 ton decrease in NO_x emissions from mobile and locomotive sources. Figure 3-10 and Table 3-5 show the breakdown of NO_x emissions by source category for 2014 and 2028.

FIGURE 3-10

NEVADA NO_x EMISSION INVENTORY – 2014 AND 2028

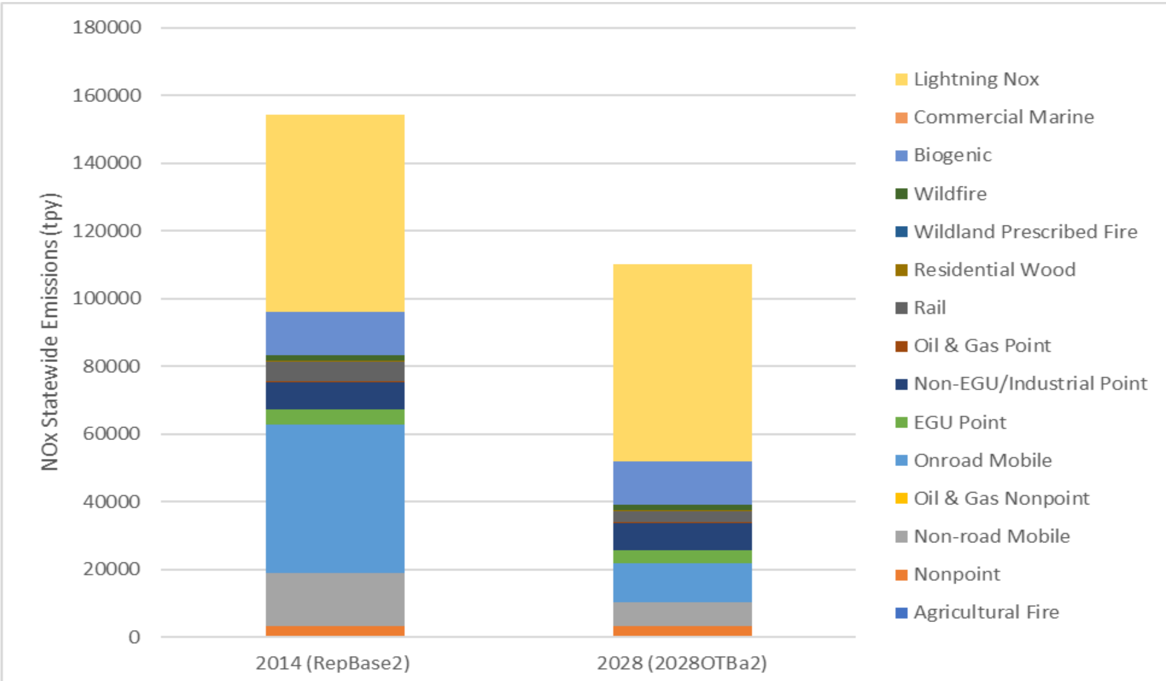


TABLE 3-5

NEVADA NO_x EMISSIONS BY SOURCE CATEGORY FOR 2014 AND 2028

Source Category	2014 (RepBase2)	2017 (NEI)	2028 (2028OTBa2)	Net Change
Agricultural Fire	5	11	5	0%
Biogenic	12613	38548	12613	0%
Commercial Marine	29	0	16	-45%
Lightning Nox	58480	0	58480	0%
Nonpoint	3297	9677	3296	0%
Non-road Mobile	15468	14589	7094	-54%
Oil & Gas Nonpoint	3	2	3	0%
Onroad Mobile	44155	28507	11282	-74%
EGU Point	4310	3162	3869	-10%
Non-EGU/Industrial Point	8129	8850	8129	0%
Oil & Gas Point	215	195	215	0%
Rail	5768	4353	3305	-43%
Residential Wood	181	183	181	0%
Wildland Prescribed Fire	91	59	91	0%

Wildfire	1754	4875	1754	0%
Total	154498	113011	110333	-29%

Figure 3-11, "Regional Maps of NOx Emissions for 2028," shows that Nevada, with 110,334 tpy statewide, is not a significant contributor to NOx emissions in the West compared to other states.

FIGURE 3-11

REGIONAL MAP OF NO_x EMISSIONS FOR 2028

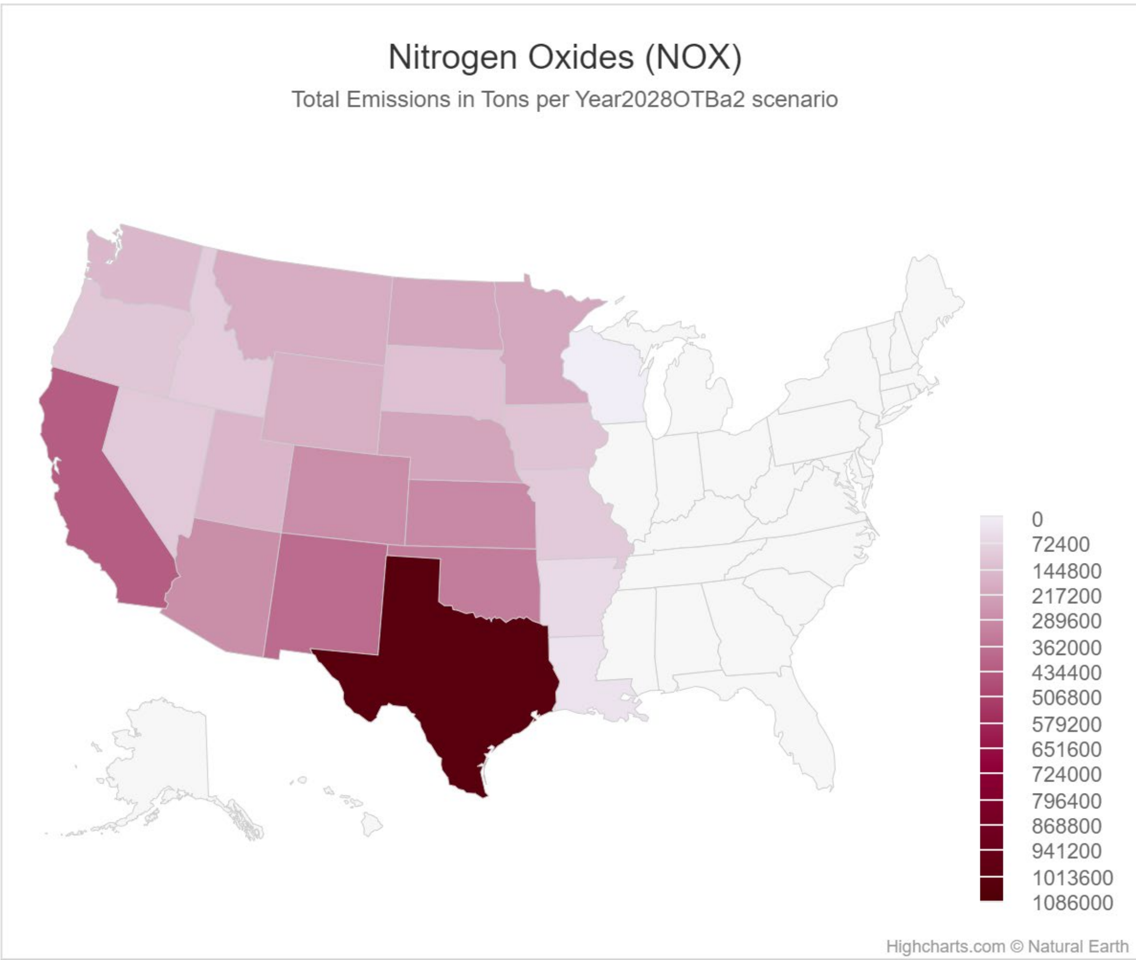
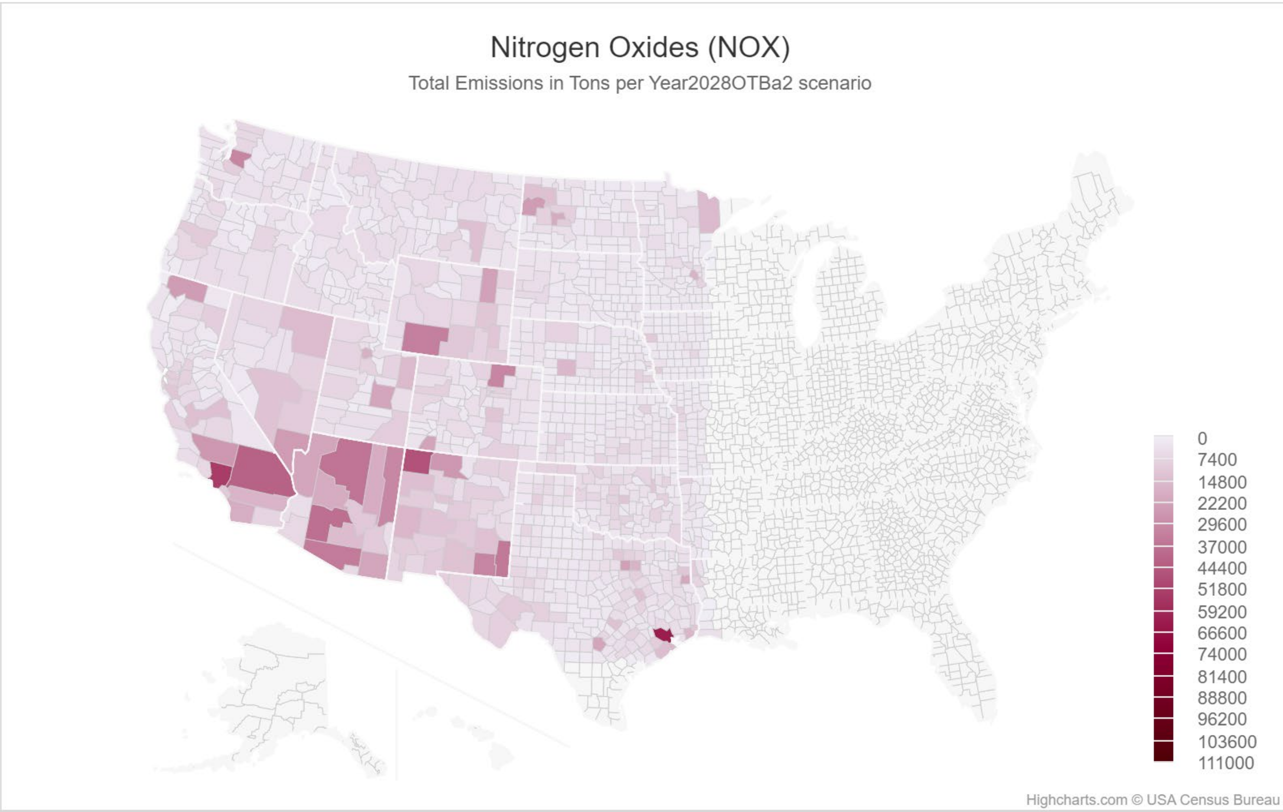


Figure 3-12, shows NOx emissions by county, indicating that Nevada's counties that emit the most NOx emissions are Clark County, emitting roughly 25,000 tpy NOx, and Elko county, emitting roughly 15,000 tpy. This is primarily due to the industrial facilities that are located in these counties.

FIGURE 3-12

NITROGEN OXIDES EMISSIONS BY COUNTY FOR 2028



3.8.3 Nevada VOC Emission Inventory for 2014 and 2028

VOCs are emitted as gases from certain solids or liquids. VOCs are emitted by a wide array of products numbering in the thousands. Examples include paints and lacquers, paint strippers, cleaning supplies, pesticides, building materials and furnishings, office equipment such as copiers and printers, correction fluids and carbonless copy paper, craft materials including glues and adhesives, permanent markers and photographic solutions (https://www.epa.gov/indoor-air-quality-iaq/what-are-volatile-organic-compounds-vocs). Automobiles, industrial and commercial facilities, and refueling of automobiles all contribute to VOC loading in the atmosphere. Substantial natural emissions of VOCs come from vegetation; these emissions are categorized as biogenics. VOCs can directly impact visibility as emissions condense in the atmosphere to form an aerosol. Of more significance is the role VOCs play in the photochemical production of ozone in the troposphere. VOCs react with nitrogen oxides to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. VOCs in Nevada are expected to decrease slightly (less than 1 percent) by 2028.

Figure 3-13 and Table 3-6 show the overall net zero percent change in emissions from 2014 to

2028 for VOCs. Biogenic sources, primarily from terpenes, dominate VOC emissions at approximately 90 percent for both 2014 and 2028. Overall, VOC emissions in Nevada are expected to decline, primarily due to significant reductions in emissions from non-road mobile sources (20 percent net decrease), on-road mobile sources (60 percent decrease), and rail (53 percent decrease) primarily due to new federal vehicle and locomotive emission standards. This equates to a 14,641 ton decrease in VOC emissions from mobile and locomotive sources.

FIGURE 3-13

NEVADA VOC EMISSION INVENTORY – 2014 AND 2028

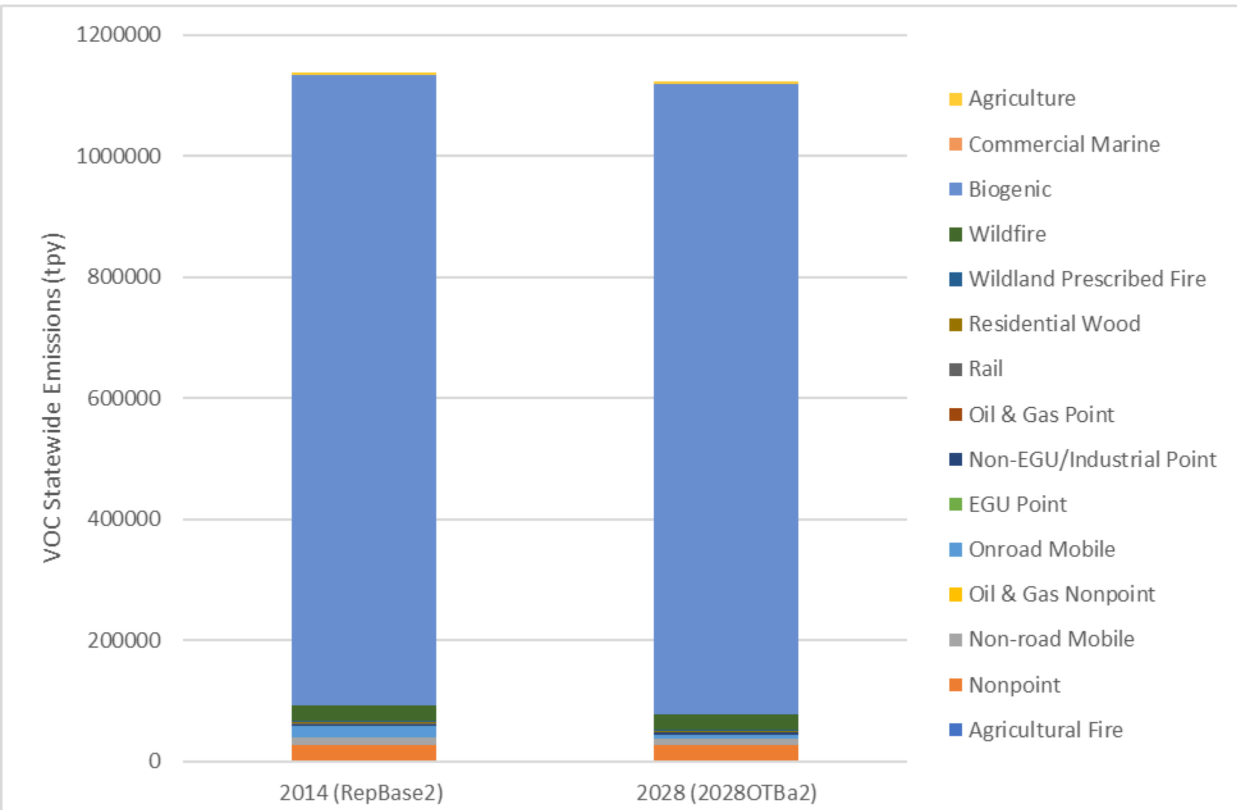


TABLE 3-6

NEVADA VOC EMISSIONS BY SOURCE CATEGORY FOR 2002 AND 2018

Source Category	2014 (RepBase2)	2017 (NEI)	2028 (2028OTBa2)	Net Change
Agriculture	3839	1390	3811	-1%
Agricultural Fire	8	47	8	0%
Biogenic	1041460	343041	1041460	0%
Commercial Marine	2	0	2	0%
Nonpoint	27641	32960	27650	0%

Non-road Mobile	10999	10135	8814	-20%
Oil & Gas Nonpoint	199	149	199	0%
Onroad Mobile	20353	16101	8055	-60%
EGU Point	106	454	102	-4%
Non-EGU/Industrial Point	2232	3013	2230	0%
Oil & Gas Point	54	32	54	0%
Rail	299	205	141	-53%
Residential Wood	2656	3811	2655	0%
Wildland Prescribed Fire	2951	838	2951	0%
Wildfire	25760	48005	25760	0%
Total	1138559	460181	1123892	-1%

Figure 3-14, shows relative contributions to VOC emissions among the western states. Nevada, although not the highest emitting western states, still emits a significant estimate of 1,123,892 tpy VOC for 2028 projections.

FIGURE 3-14

REGIONAL MAP OF VOC EMISSIONS FOR 2028

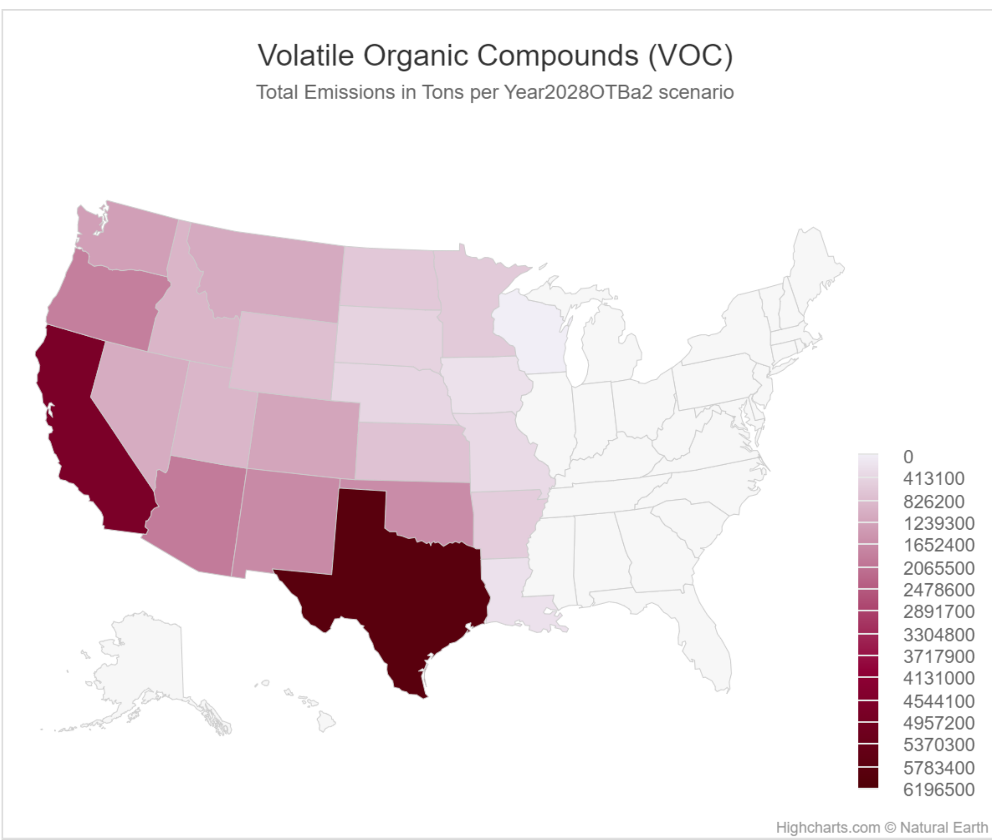
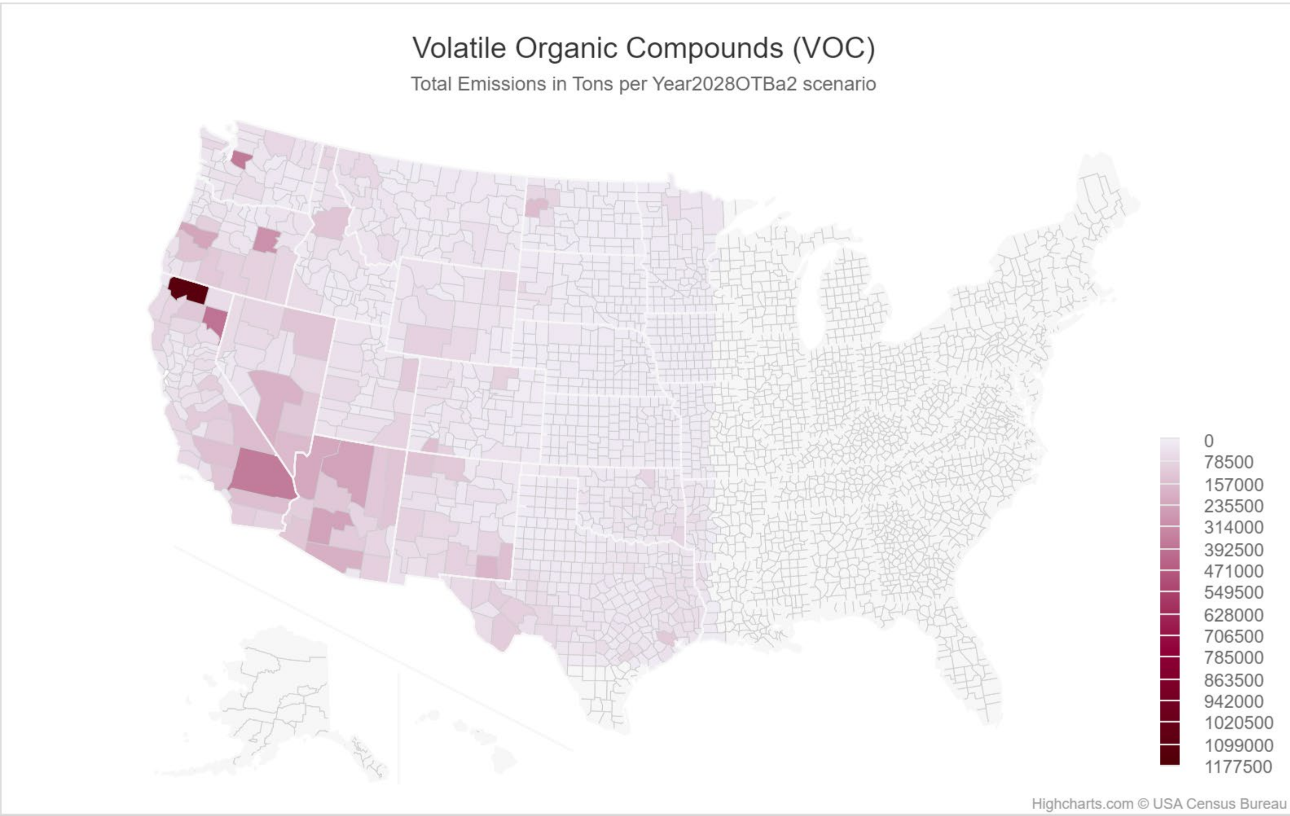


Figure 3-15 shows VOC emissions by county. Biogenic sources dominate the VOC emissions for all counties in Nevada. Biogenic and natural fire emissions were held constant for the 2028 projections.

FIGURE 3-15

VOLATILE ORGANIC COMPOUNDS EMISSIONS BY COUNTY FOR 2028



3.8.4 Nevada PM 2.5 Emission Inventory for 2014 and 2028

PM fine emissions are comprised of fine particulates under 2.5 microns that are generated mostly from area sources, road dust and fugitive dust, as observed at the Jarbidge Wilderness area. PM fine emissions are largely related to agricultural and mining activities, windblown dust from construction areas, and emissions from unpaved and paved roads. PM fine emissions are also generated from combustion sources. A particle of fine dust has a relative impact on visibility one-tenth as great as a particle of elemental carbon. For any given visibility event where poor visual air quality is present in a scene, the impact of dust can vary widely. Agricultural activities, dust from unpaved roads and construction are prevalent in this source category and changes in emissions are tied to population and vehicle miles traveled. Since PM fine emissions are not directly from the tailpipe of the vehicle, the mobile source categories do not show any fine particulates emissions; all vehicle-related emissions from paved and unpaved roads show up in the fugitive dust category. Fine particulate matter can remain suspended in the atmosphere for long periods of time and travel long distances. Fine particulates can efficiently scatter the transmission of light that contributes to visibility reduction on a regional scale at Class I areas. For 2028 projected emissions windblown dust was held constant.

In Figure 3-16 and Table 3-7, the projected statewide PM fine emission net decrease is 4 percent and is largely dominated by fugitive dust (expected to slightly increase) and wildfire (held constant for 2028 projections). Overall, VOC emissions in Nevada are expected to decline, primarily due to significant reductions in emissions from non-road mobile sources (49 percent net decrease), on-road mobile sources (53 percent decrease), and rail (49 percent decrease) primarily due to new federal vehicle and locomotive emission standards. This equates to a 1,530 ton decrease in $PM_{2.5}$ emissions from mobile and locomotive sources. A slight decrease in $PM_{2.5}$ emissions is also expected among Non-EGU or industrial point sources.

FIGURE 3-16

PM 2.5 (PM FINE) EMISSION INVENTORY – 2014 AND 2028

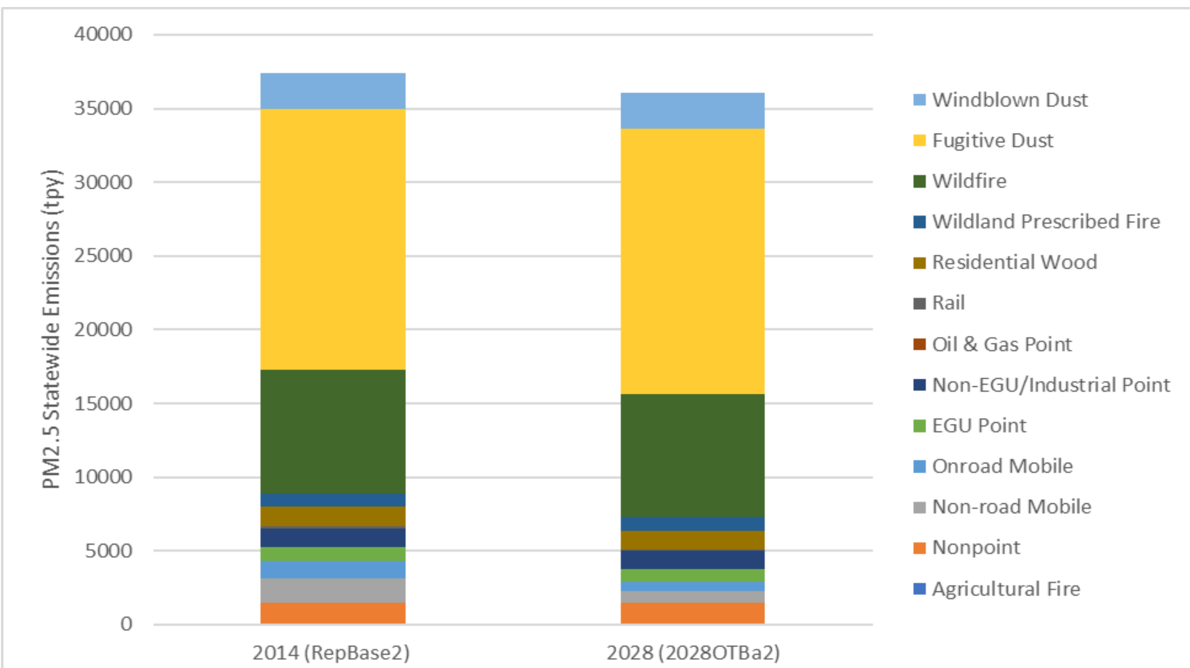


TABLE 3-7

PM 2.5 (PM FINE) EMISSIONS BY SOURCE CATEGORY FOR 2014 AND 2028

Source Category	2014 (RepBase2)	2017 (NEI)	2028 (2028OTBa2)	Net Change
Fugitive Dust	17719	17898	18016	2%
Agricultural Fire	23	46	23	0%

Nonpoint	1440	2394	1440	0%
Non-road Mobile	1625	1561	825	-49%
Onroad Mobile	1227	823	581	-53%
EGU Point	901	860	901	0%
Non-EGU/Industrial Point	1303	1995	1210	-7%
Oil & Gas Point	13	14	13	0%
Rail	170	125	86	-49%
Residential Wood	1300	1339	1299	0%
Wildland Prescribed Fire	898	314	898	0%
Windblown Dust	2416	0	2416	0%
Wildfire	8344	18938	8344	0%
Total	37379	46307	36052	-4%

Figure 3-17, "Regional Maps of $PM_{2.5}$ Emissions for 2028," shows that Nevada, with 36,000 tpy statewide, is not a significant contributor to $PM_{2.5}$ emissions in the West compared to other states.

FIGURE 3-17

REGIONAL MAP OF PM 2.5 EMISSIONS FOR 2028

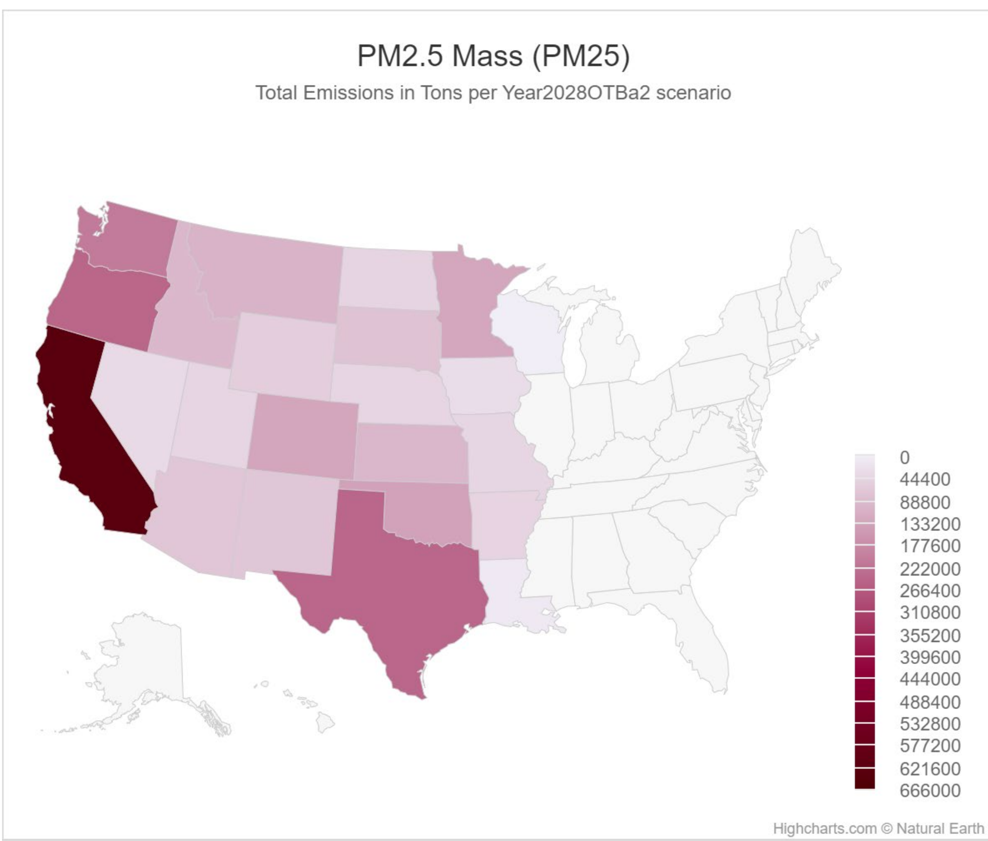
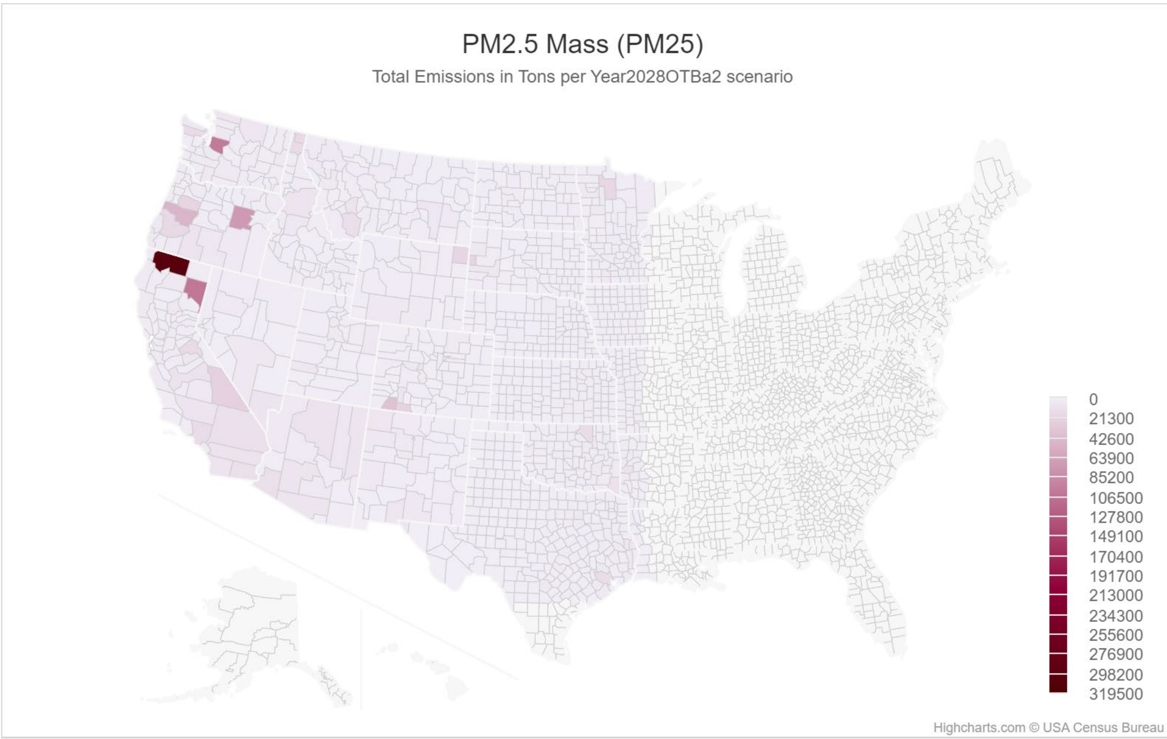


Figure 3-18 shows $PM_{2.5}$ emissions by county, indicating that none of Nevada's counties are a significant emitter of $PM_{2.5}$.

FIGURE 3-18

PM 2.5 EMISSIONS BY COUNTY FOR 2028



3.8.5 Nevada PM 10 Emission Inventory for 2014 and 2028

PM coarse emissions are closely related to the same sources as PM fine emissions but other activities like rock crushing and processing, material transfer, open pit mining and unpaved road emissions can be prominent sources. PM coarse emissions travel shorter distances in the atmosphere than other smaller particles but can remain in the atmosphere sufficiently long enough to play a role in regional haze. PM coarse emissions have the smallest direct impact on regional haze on a particle-by-particle basis where one particle of coarse mass has a relative visibility weight of 0.6 compared to a carbon particle having a weight of 10. Nevertheless, they are commonly present at all monitoring sites and are a greater contributor to regional haze than the PM fine component.

Figure 3-19 and Table 3-8 show the overall net decrease in PM coarse emissions of 0 percent, as the largest sources sectors of PM10 emissions were held constant. Large sectors that were held constant, or nearly constant, include fugitive dust, windblown dust, and wildfire emissions. NDEP considers these estimations very conservative, as the impacts of climate change and drier climate conditions in Nevada will likely lead to increases in windblown dust and wildfire emissions over future years. Although PM coarse emissions from fugitive dust decrease by 2 percent by 2028, fugitive dust is still the primary source category for these emissions. Fugitive dust is also projected to be the largest contributor to PM coarse emissions in 2028 at almost 80 percent of total statewide emissions.

FIGURE 3-19

PM 10 (PM COARSE) EMISSION INVENTORY – 2014 AND 2028

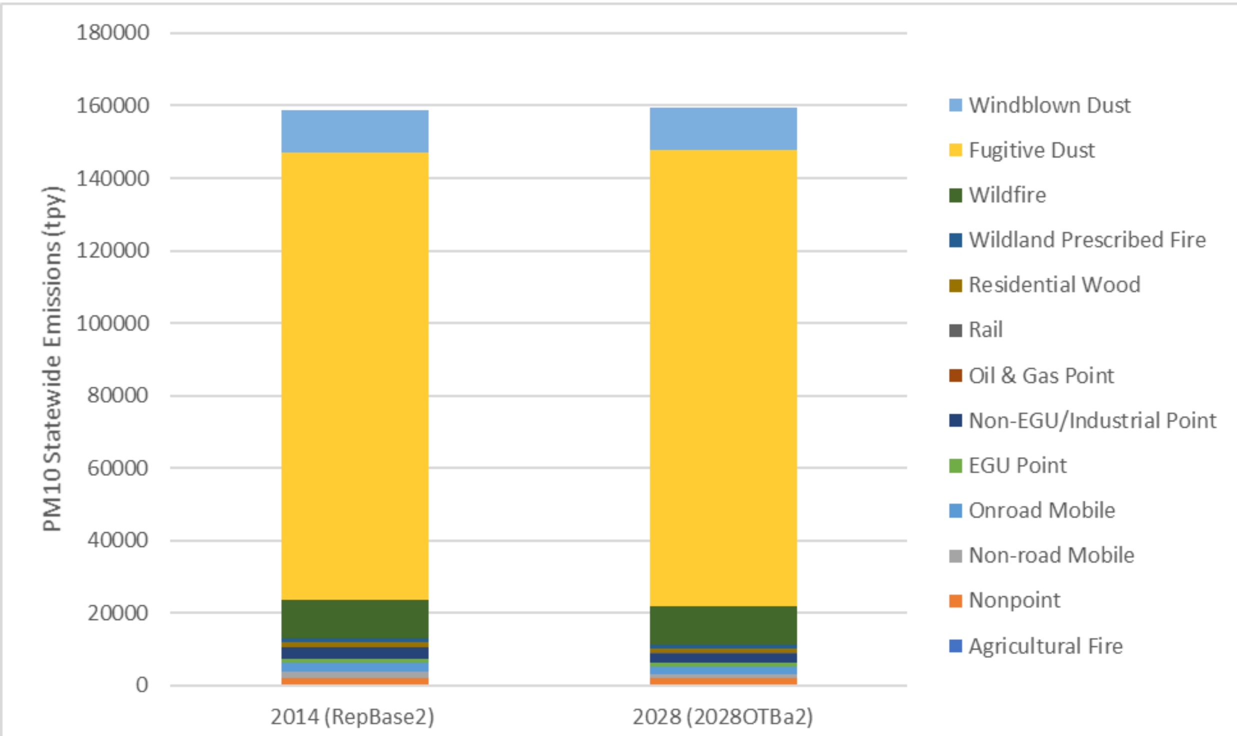


TABLE 3-8

PM 10 (PM COARSE) EMISSIONS BY SOURCE CATEGORY FOR 2014 AND 2028

Source Category	2014 (RepBase2)	2017 (NEI)	2028 (2028OTBa2)	Net Change
Fugitive Dust	123476	134709	125666	2%
Agricultural Fire	32	66	32	0%
Nonpoint	2025	2742	2025	0%
Non-road Mobile	1704	1636	878	-48%
Onroad Mobile	2477	1811	2157	-13%
EGU Point	1211	907	1034	-15%

Non-EGU/Industrial Point	3011	3540	2735	-9%
Oil & Gas Point	13	14	13	0%
Rail	184	129	88	-52%
Residential Wood	1303	1343	1303	0%
Wildland Prescribed Fire	1046	370	1046	0%
Windblown Dust	11685	0	11685	0%
Wildfire	10641	22347	10641	0%
Total	158808	169614	159303	0%

Figure 3-20 shows relative contributions to PM 10 emissions among the western states. Nevada, although not the highest emitting western states, still emits a significant estimate of roughly 160,000 tpy PM 10 for 2028 projections.

FIGURE 3-20

REGIONAL MAP OF PM 10 EMISSIONS FOR 2028

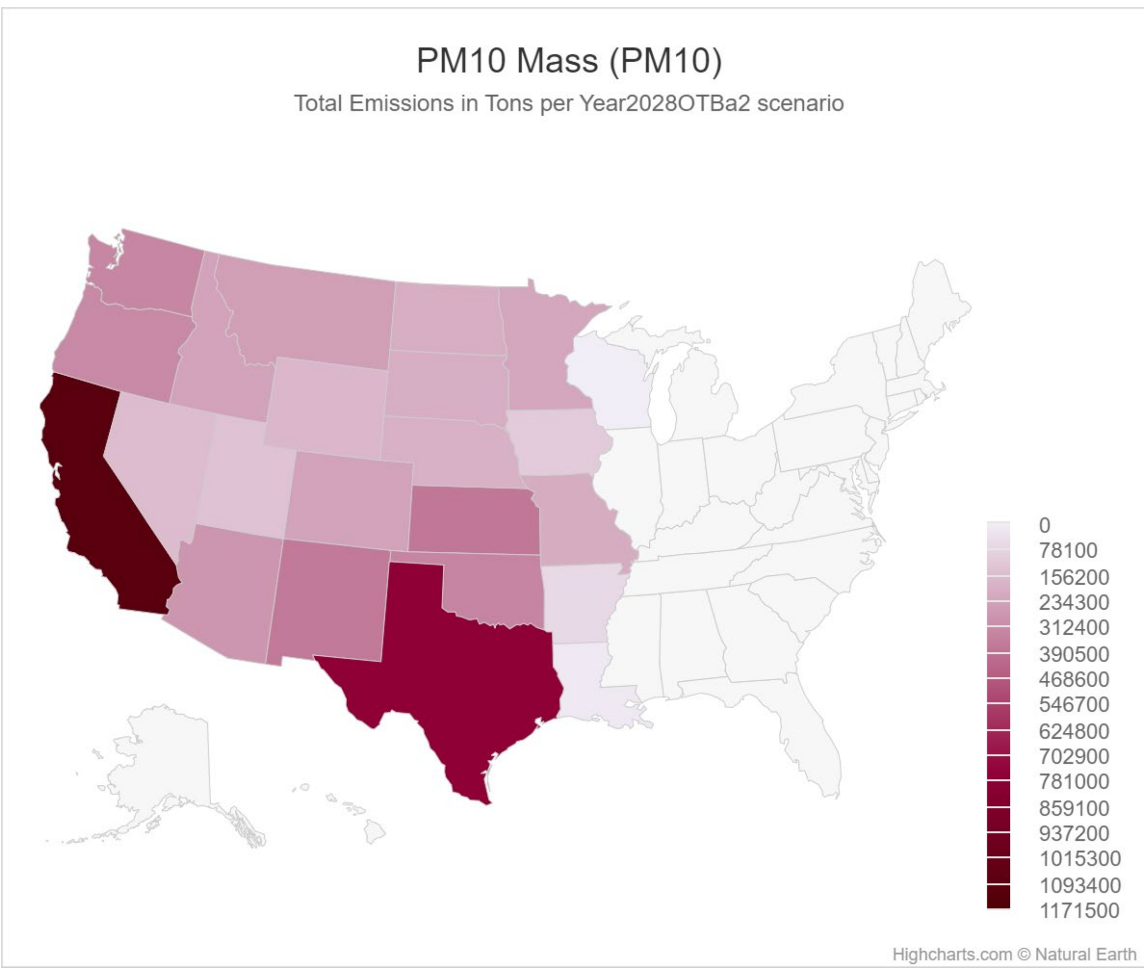
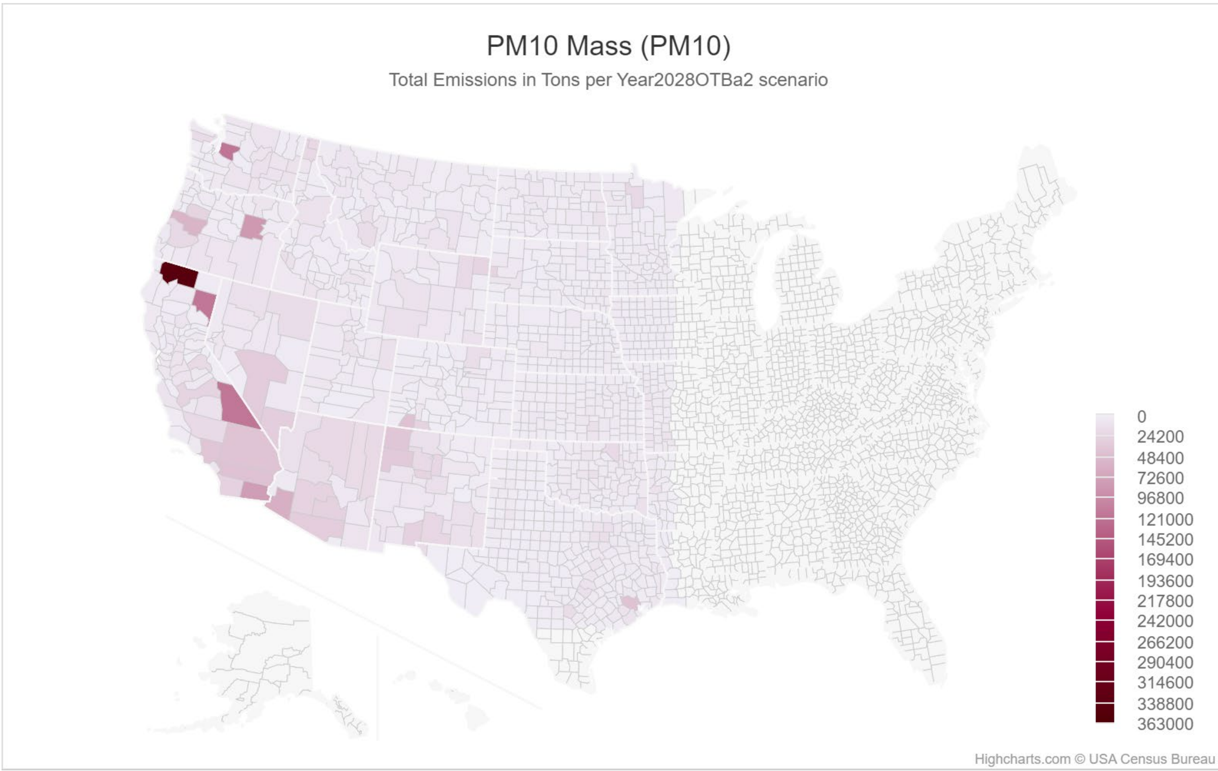


Figure 3-21, shows PM_{10} emissions by county, indicating that Nevada's counties that emit the most PM_{10} emissions are Clark County and Nye County, both emitting roughly 30,000 tpy.

FIGURE 3-21

PM 10 EMISSIONS BY COUNTY FOR 2028



3.8.6 Nevada NH_3 Emission Inventory for 2014 and 2028

NH_3 emissions come from a variety of sources including wastewater treatment facilities, livestock operations, fertilizer applications and mobile sources. NH_3 is directly linked to the production of ammonium nitrate and ammonium sulfate particles in the atmosphere when SO_2 and NO_x eventually convert over to these forms of particles. Increases in NH_3 emissions from the base case year to 2018 are linked to population statistics and increased vehicular traffic.

An EPA report "Estimating Ammonia Emissions from Anthropogenic Non-Agricultural Sources – Draft Final Report April 2004" documents that NH_3 measurements vary substantially by vehicle class in on-road mobile sources. Fleet-average NH_3 emissions are thought to be increasing as advanced catalyst-equipped vehicles make up a larger fraction of the fleet. Advanced catalysts have higher NH_3 emission rates stemming from an over-reduction of NO_x to NH_3.

Non-road mobile sources include exhaust emissions from a wide range of non-road engines. These include construction equipment, agricultural equipment, lawn and garden equipment, commercial and recreational marine vessels and locomotives. Non-road gasoline engines typically are not equipped with catalysts.

Figure 3-22 and Table 3-9, show an overall net decrease of NH_3 emissions of 1 percent. NH_3 emissions are dominated by agriculture emissions, accounting for over 80 percent of total statewide emissions. On-road mobile NH_3 emissions are projected to slightly decrease.

FIGURE 3-22

NEVADA NH_3 EMISSION INVENTORY – 2014 AND 2028

TABLE 3-9

NEVADA NH_3 EMISSIONS BY SOURCE CATEGORY FOR 2014 AND 2028

Source Category	2014 (RepBase2)	2017 (NEI)	2028 (2028OTBa2)	Net Change
Agriculture	16908	29306	16893	0%
Agricultural Fire	16	43	16	0%
Nonpoint	513	561	519	1%
Non-road Mobile	26	28	31	19%
Onroad Mobile	893	844	770	-14%
EGU Point	298	425	298	0%
Non-EGU/Industrial Point	100	65	100	0%
Rail	3	3	3	0%

Residential Wood	51	48	51	0%
Wildland Prescribed Fire	148	58	148	0%
Wildfire	1380	3339	1380	0%
Total	20336	34720	20209	-1%

Figure 3-23, "Regional Maps of NH_3 Emissions for 2028," shows that Nevada, with 20,000 tpy statewide, is not a significant contributor to NH_3 emissions in the West compared to other states.

FIGURE 3-23

REGIONAL MAP OF NH_3 EMISSIONS FOR 2028

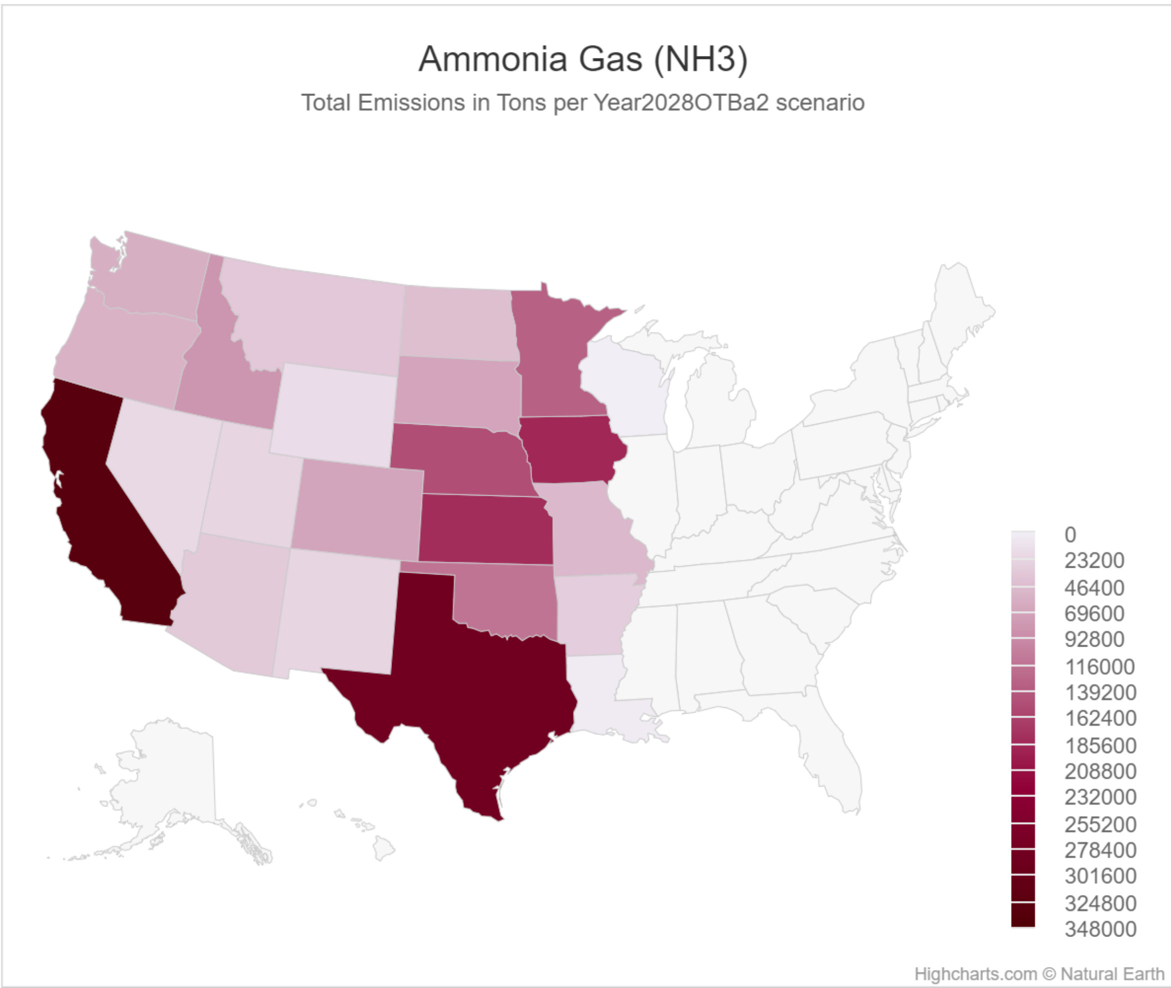
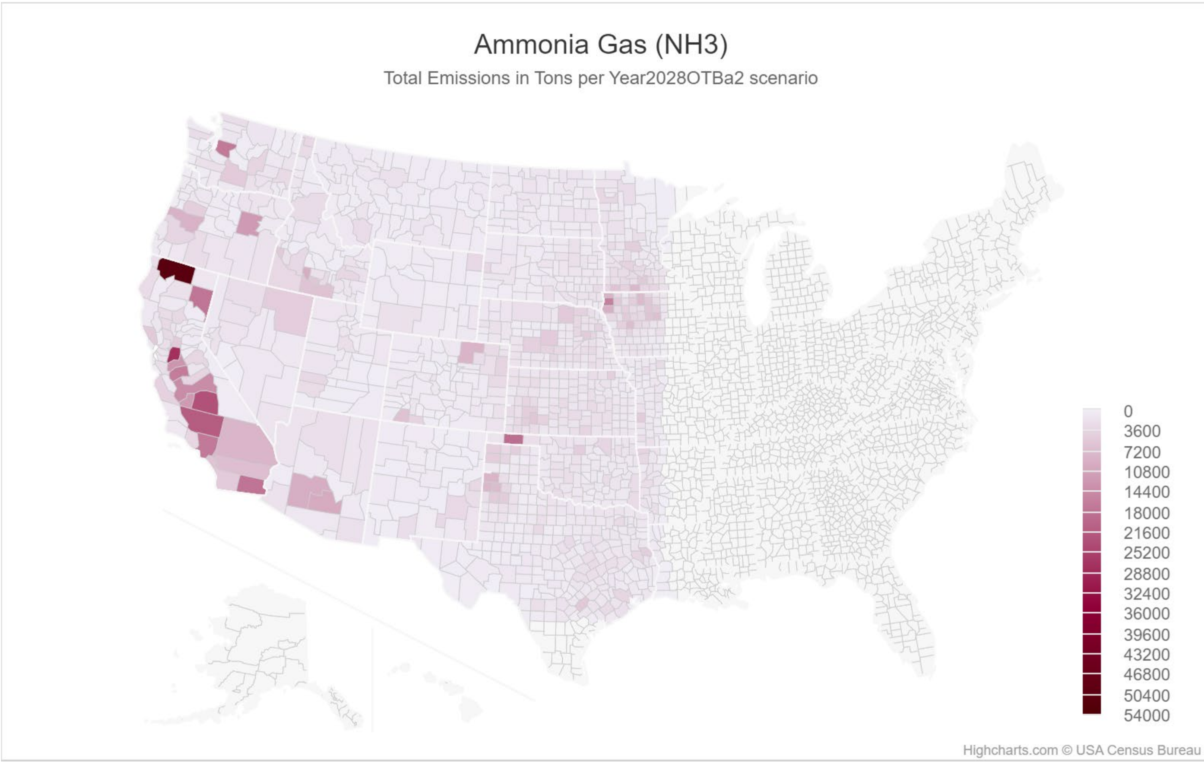


Figure 3-24 shows that Elko County is the highest emitter of NH_3 in Nevada, with roughly 4,000 tpy. Elko, being one of Nevada's more rural counties, has more emissions due to agriculture.

FIGURE 3-24

AMMONIA EMISSIONS BY COUNTY FOR 2028



3.9 SUMMARY OF 2028 EMISSION PROJECTIONS

Analysis of the IMPROVE monitoring network data demonstrates the following pollutants, ranked according to percent contribution to annual extinction (see Table 2-6), contribute to reconstructed light extinction at JARB1 for the 20 percent most impaired days of the baseline period.

- SO_4
- OMC
- CM
- NO_3
- EC
- Fine Soil
- Sea Salt

The emissions analysis is part of the technical basis for identifying Nevada's reasonable progress goal. At the beginning of this section, Table 3-2 summarizes the contribution from natural vs. anthropogenic sources for each pollutant in 2014 and 2028. It shows that approximately three quarters (73 percent) of emissions in 2028 are expected to be from natural sources and, therefore, uncontrollable. Table 3-10 shows percent contribution from anthropogenic sources and dominant source categories for each pollutant in 2028. The "Total Emissions from All Source Categories" column includes natural emissions and puts the contribution from each pollutant into perspective with respect to other visibility impairing pollutants in Nevada.

TABLE 3-10

PREDOMINANT SOURCES OF POLLUTANTS IN 2028

Pollutant	Total Emissions from All Source Categories in tpy *(percent of total)*	Percent from Anthropogenic Sources	Predominant Source and Percent from Predominant Source		Controllable
VOC	1,123,892 *(77)*	5	Biogenic	92	No
PM_{10}	159,618 *(11)*	86	Fugitive Dust	79	Yes
NO_x	110,334 *(8)*	34	Lightning NOx	53	No
			Biogenic	11	No
			Onroad Mobile	10	Yes
$PM_{2.5}$	36,144 *(2)*	70	Fugitive Dust	50	Yes
			Wildfire	23	No
NH_3	20,210 *(1)*	93	Agriculture	83	Yes
SO_2	8,260 *(<1)*	92	Nonpoint/Area	42	Yes
			EGU Point	31	Yes
			Non-EGU Point	16	Yes

In Nevada, anthropogenic sources are important contributors of SO_2, PM_{10}, $PM_{2.5}$, and NH_3 in 2028. SO_2 emissions are predominantly from nonpoint sources, 42 percent; point sources contribute 47 percent. PM_{10} emissions are predominantly from fugitive dust at 79 percent and $PM_{2.5}$ emissions are also predominantly from fugitive dust at 50 percent, along with wildfire at 23 percent. NH_3 emissions are predominantly from agriculture, at 83 percent.

VOC and NOx emissions are dominated by natural source categories, and primarily are not controllable for those sources. VOC emissions are largely dominated by biogenic at 92 percent. NO_x emissions are predominantly from lightning NOx, approximately 50 percent, while biogenic emissions account for 11 percent and mobile sources account for another 10 percent. The total projected emissions for all pollutants in 2028 are 1,458,458 tons and of that total, only 19 percent are controllable.

3.10 REFERENCES

U.S. EPA 2019. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. EPA-457/B-19-003. August 2019.

U.S. EPA 2021. Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period. July 2021.

Chapter Four – Visibility and Source Apportionment Modeling

4.1 INTRODUCTION

Federal visibility regulations at 40 CFR 51.308(f)(2)(iii) require that states document the technical basis, including modeling, 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. Air quality modeling analyses were performed to determine which Class I areas are affected by emissions from Nevada and to evaluate reasonable progress, as discussed in Chapter One. The Western Regional Air Partnership's (WRAP) Emissions Inventory and Modeling Protocols Subcommittee (EIMP), along with its contractor, Ramboll Inc., performed these modeling analyses for the WRAP states, including Nevada.

Visibility modeling results indicate that the Jarbidge Wilderness Area (Jarbidge WA) will meet the Uniform Rate of Progress (URP) for 2028. Note that 2028 visibility projections from the 2028OTBa2 do not accurately reflect the final expected emission reductions as a result of reasonable progress controls, which are larger than what was predicted in the model. Nevada's RPG reflecting actual achieved emission reductions is developed in Chapter Six, using 2028OTBa2 visibility projections as a foundation with adjustments made for corrected emission reductions.

The modeling results and technical analyses also indicate Nevada sources do contribute to visibility impairment at the Jarbidge WA, as well as Class I areas located in adjacent states. The modeling also indicates that international and natural sources have the greatest impact on regional haze in Nevada.

The visibility and source apportionment modeling described in this chapter provides, in conjunction with the monitoring and emissions analyses, the technical basis used to identify and evaluate reasonable progress for the Jarbidge WA.

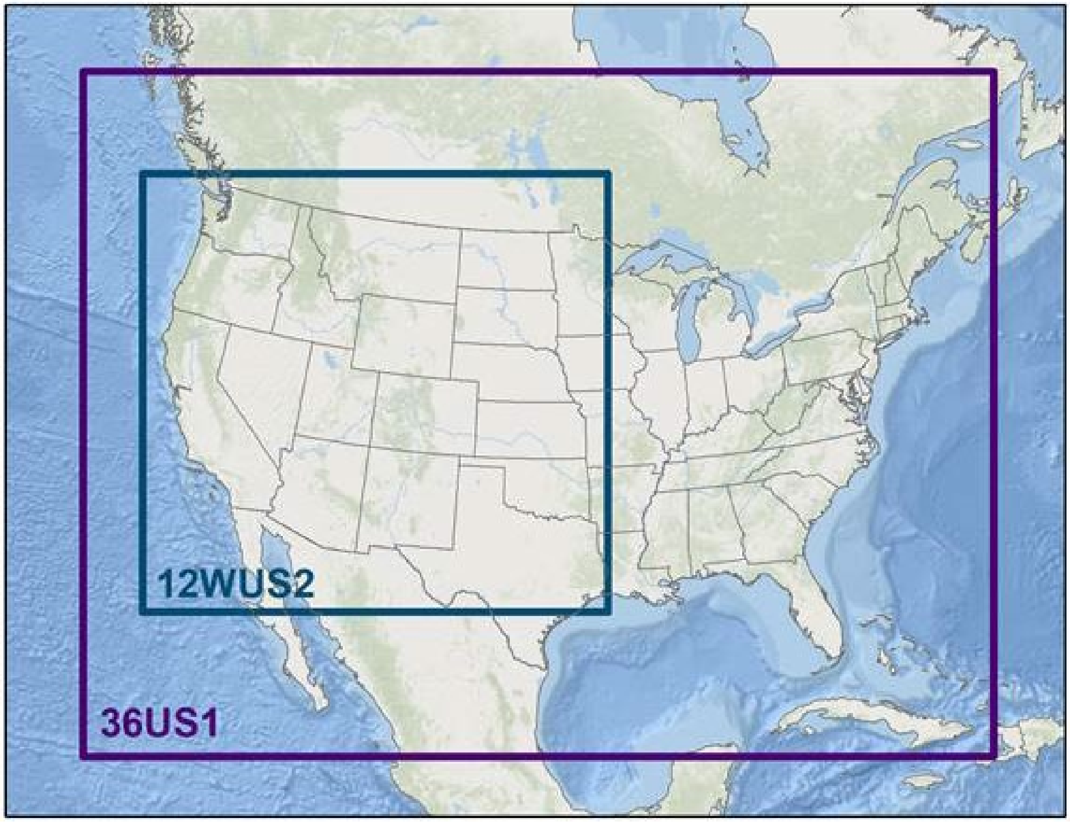
4.1.1 Air Quality Models

The WRAP-WAQS 2014 modeling platform was developed and performed by Ramboll, Inc., under contract to WESTAR-WRAP.[1] The 2014 modeling platform used the Weather Research and Forecasting (WRF) meteorological model, the Sparse Matrix Operator Kerner Emissions (SMOKE) model and the Comprehensive Air Quality Model with Extensions (CAMx) to project air quality for the 2014 base year. The Goddard Earth Observing System global chemical model (GEOS-Chem) provided global boundary conditions for the regional CAMx model for the 2014 base year. The CAMx 2014v2 final model configuration is defined in Table 1 of the WRAP-WAQS 2014 modeling platform webpage. CAMx version 7beta 6 was used for the 2014v2 model performance run, while CAMx version 7.0 was used for the subsequent model scenarios. Figure 1 below illustrates the CAMx 36-km modeling domain covering the Continental United States and the 12-km modeling domain covering the western states.

[1] https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

FIGURE 4-1

WRAP-WAQS 2014 MODELING DOMAINS



In addition to the 2014v2 model year, model runs were made using 2014 meteorology and with Representative Baseline (2014-2028, RepBase2), 2028 On the Books (2028OTBa2), 2028 Potential Additional Controls (2028PAC2), 2014 Hindcast, and Future Fire Sensitivities emission scenarios. Details are provided in model run specification sheets:

- Representative Baseline (RepBase2) and 2028 On the Books (2028OTBa2) CAMx simulations[2]
- Dynamic Evaluation – 2014 Simulations[3]
- Future Fire Sensitivity Simulations[4]

---

2 https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/EmissionsSpecifications_WRAP_RepBase2_and_2028OTBa2_RegionalHazeModelingScenarios_Sept30_2020.pdf

3 https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/Run_Spec_WRAP_2014_Task3_Dynamic-Evaluation_v1.pdf

4 https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/Run_Spec_WRAP_Future_Fire_Sensitivities_August4_2021_final.pdf

4.1.2 Model Performance Evaluation

The objective of the model performance evaluation was to compare model-simulated concentrations with observed data to determine whether the model's performance was sufficiently accurate to justify using the model for simulating future conditions, as discussed in Chapter One. The model was compared to ambient data for both particulate matter and gaseous species, for an annual time period and for a large number of sites. A summary of WRAP-WAQS 2014v2 CAMx Model Performance Evaluation is available by Ramboll Inc.[5]

The WRAP-WAQS 2014v2 modeling platform webpage includes statistical model performance measures compared to EPA goals and criteria, spatial data plots and timeseries plots for the aerosol species listed below. For aerosol species concentrations, CAMx 2014v2 model outputs are compared to 2014 observations from the IMPROVE, Chemical Speciation Network (CSN) and Clean Air Status and Trends (CASTNET) monitoring network.

- Ozone model performance is reported on the Intermountain West Data Warehouse.

CAMx 2014v2 performance was evaluated using the EPA Atmospheric Model Evaluation tool (AMET) to compare model outputs to 2014 ambient air quality measurements (in µg/m3) for:

- Particulate matter less than 2.5 micrometers
- Nitrate (NO_3)
- Sulfate (SO_4)
- Organic mass from carbon (OMC)
- Elemental carbon (EC)
- Fine soil (Soil)
- Coarse mass (particulate matter between 2.5 and 10 micrometers).
- Seasalt: performance is tracked separately for Sodium and Chloride

Spatial plots of the Normalized Mean bias statistic for the winter months January - March and Summer months July – September, for Nitrate and Sulfate, respectively, were provided for the WRAP State IMPROVE monitoring sites. IMPROVE sites are illustrated as circles, CSN sites as triangles, and CASTNET sites as squares. Nevada's Class I area, the Jarbidge Wilderness Area, is located along Nevada's northern border. In winter, Nitrates and Sulfates are overpredicted at Jarbidge, as shown in Figures 4-2 and 4-3. During the summer months, model performance is within 10 percent and are predicted accurately, as shown in Figures 4-4 and 4-5.

[5] http://vice.cira.colostate.edu/files/iwdw/platforms/WRAP_2014/MPE/WRAP-WAQS_2014v2_MPE_Summary.pdf

FIGURE 4-2

NORMALIZED MEAN BIAS FOR 2014v2 MODELED NITRATE COMPARISON DURING WINTER MONTHS

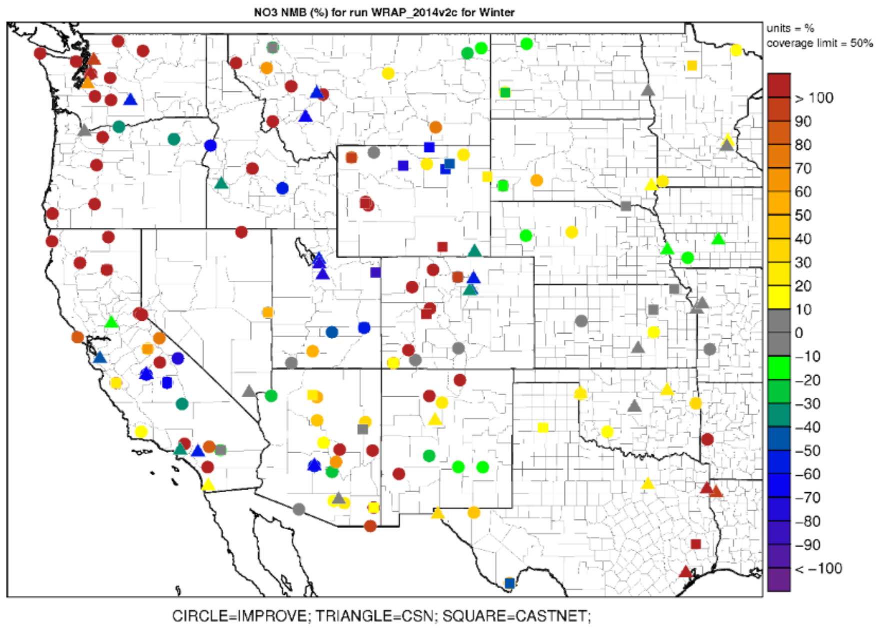


FIGURE 4-3

NORMALIZED MEAN BIAS FOR 2014v2 MODELED SULFATE COMPARISON DURING WINTER MONTHS

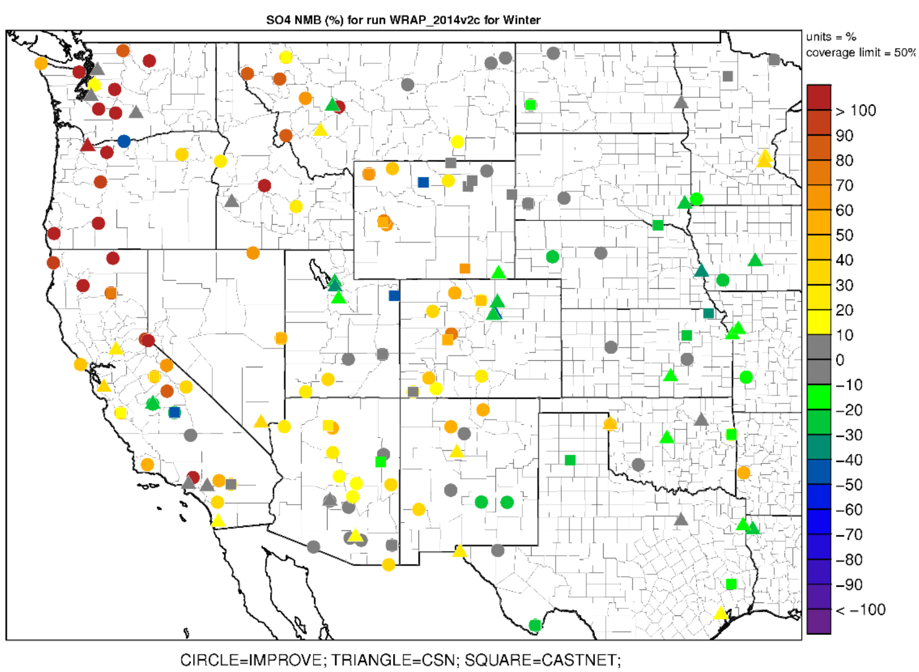


FIGURE 4-4

NORMALIZED MEAN BIAS FOR 2014v2 MODELED NITRATE COMPARISON DURING SUMMER MONTHS

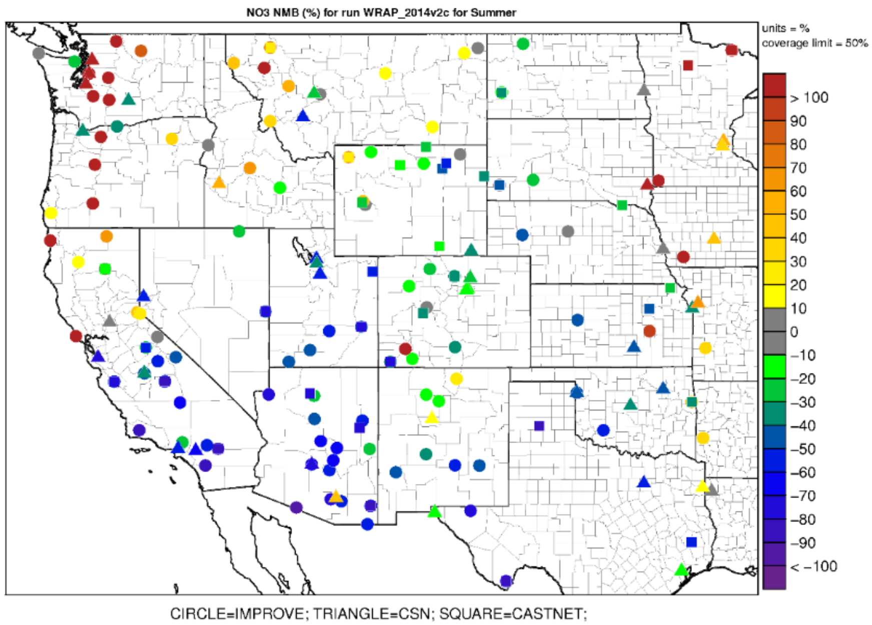
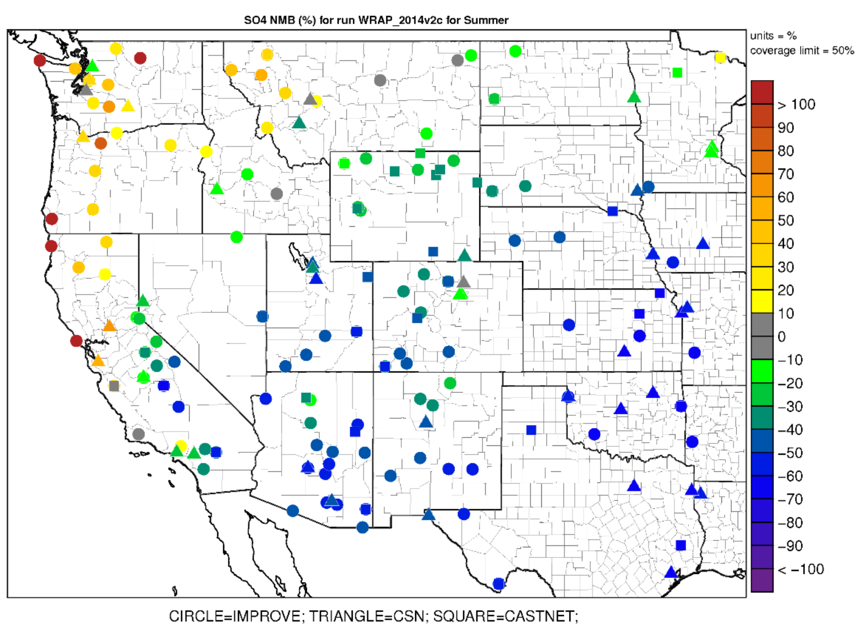


FIGURE 4-5

NORMALIZED MEAN BIAS FOR 2014v2 MODELED SULFATE COMPARISON DURING SUMMER MONTHS



4.1.2.1 2014 Most Impaired Days Performance

CAMx model performance can be roughly judged by comparing the model predicted concentration (right column of Figure 4-6) against the monitored concentration from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitor JARB1 (left column of Figure 4-6) for the most impaired days in 2014. As shown, the model generally underpredicts all pollutant species.

Figure 4-7 indicates the CAMx model under predicts, as shown by negative percentages, all six components of extinction for the most impaired days at JARB1. Nevada deems the model performance for the most impaired days is more accurate for sulfate (-34.1 percent), nitrate (-17.9 percent), organic matter (-22.0 percent), and elemental carbon (-31.0 percent), but is less accurate for soil (-92.4 percent) and coarse mass (-76.6 percent). Model performance for pollutants contributed by anthropogenic sources, like sulfate and nitrate, show a lesser margin of error, as these sources are most accurately inventoried. Pollutants contributed by natural sources, like soil and coarse mass, are represented in the model as estimated sources of emissions over vast regions and may not be as accurate to what was observed at the IMPROVE monitor.

FIGURE 4-6

CAMx MODEL PERFORMANCE FOR JARB1 2014 MOST IMPAIRED DAYS

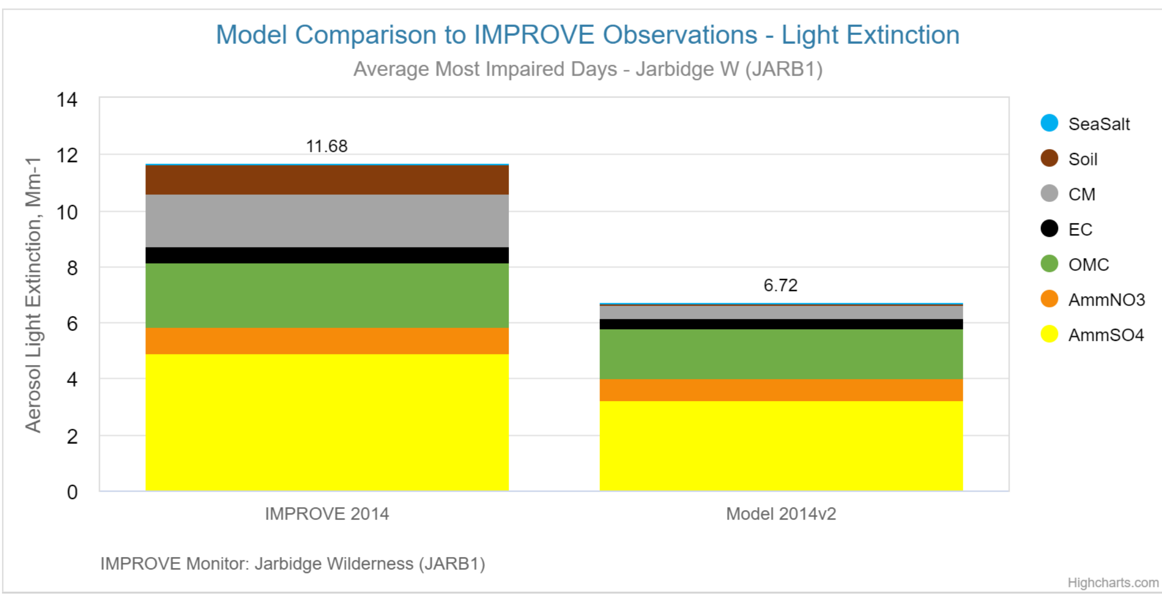
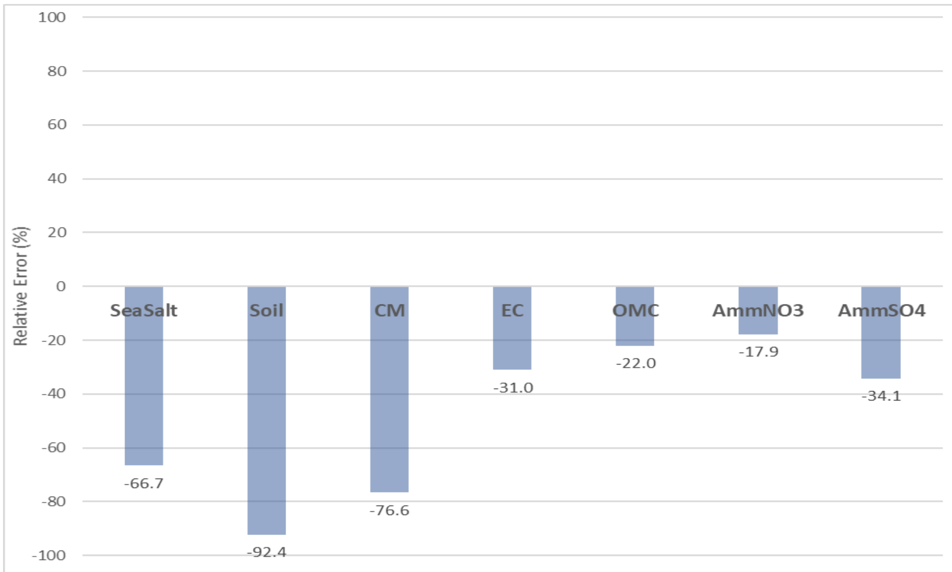


FIGURE 4-7

RELATIVE ERROR OF CAMx MODEL PREDICTION VERSUS
IMPROVE DATA FOR JARB1 2014 MOST IMPAIRED DAYS

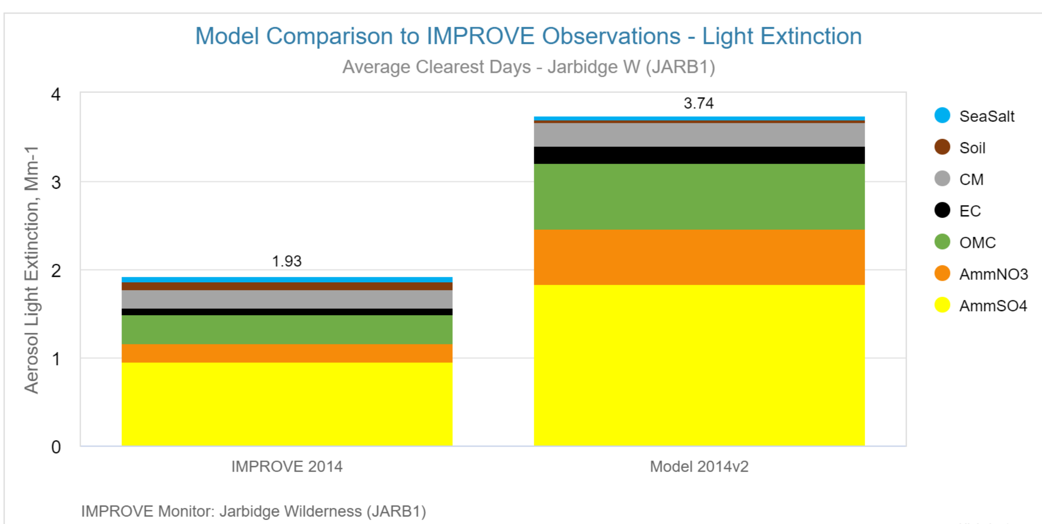


4.1.2.2 2014 Clearest Days Performance

Comparison of the model predicted concentration (right column of Figure 4-8) against the monitored concentration from the IMPROVE monitor JARB1 (left column of Figure 4-8) for the clearest days of 2014 shows a general overprediction.

FIGURE 4-8

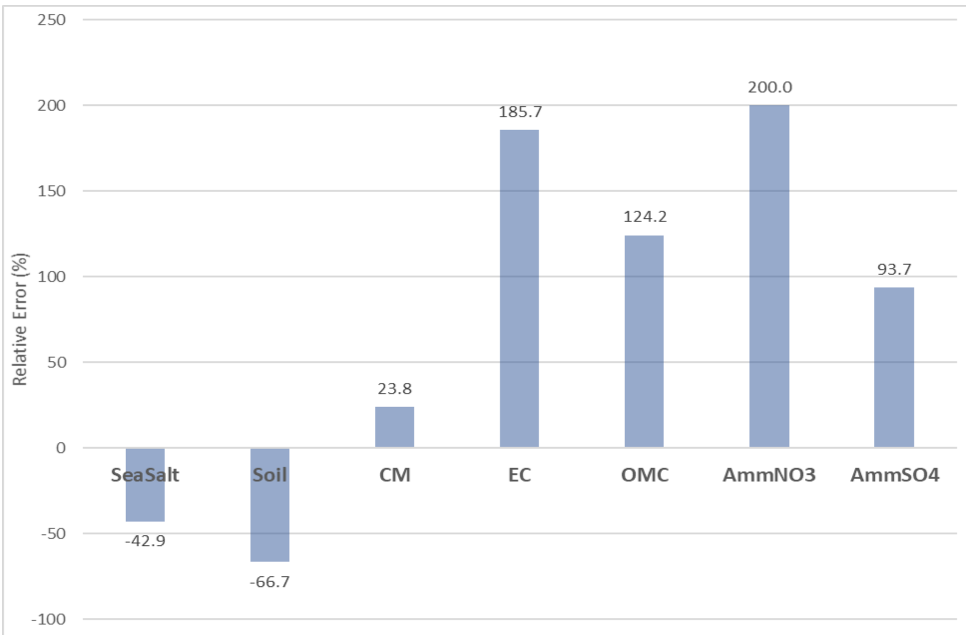
CAMx MODEL PERFORMANCE FOR JARB1 2014 CLEAREST DAYS



However, Figure 4-9 shows the model produces mixed predictions for the clearest days at JARB1. Nevada deems the model performance for the clearest days is most accurate for sea salt (-42.9 percent) and coarse mass (23.8 percent) but is marginally accurate for soil (-66.7 percent). Model performance for elemental carbon (185.7 percent), organic mass (124.2 percent), nitrate (+200 percent), and sulfate (+93.7 percent) are least accurate for the clearest days. Although the range of the percent error for these pollutants are unacceptable, these overpredictions in the model serve as a conservative estimate to visibility conditions for planning purposes.

FIGURE 4-9

RELATIVE ERROR OF CAMx MODEL PREDICTION VERSUS
IMPROVE DATA FOR JARB1 2014 CLEAREST DAYS



4.1.3 Weighted Emissions Potential Analysis

The WEP was developed as a screening tool for states to identify which source areas (e.g., states) have the potential to contribute to haze formation at specific Class I areas, based on both the 2014 and 2028 emissions inventories, as discussed in Chapter One. WEP was used to investigate the attribution of sources of nitrogen oxides (NO_x), sulfur oxides (SO_2), elemental carbon (EC), and organic aerosol (POA). The results of the WEP analyses are discussed below in section 4.4.

4.2 VISIBILITY MODELING RESULTS FOR 2028

Visibility modeling results indicate projected visibility conditions for the Jarbidge WA, based on the 2028OTBa2 emission inventory, will meet the URP required in 2028 (end of second implementation period) to achieve natural conditions by 2064.

4.2.1 2028 Visibility Projections for Jarbidge Wilderness Area

Table 4-1 lists the 2028 URP for the Jarbidge WA and the CAMx visibility modeling forecasts for baseline conditions in 2028. The results of this modeling will be used in establishing RPGs for the Jarbidge WA, discussed further in Chapter Six. The 2028 model forecasts indicate Jarbidge WA will meet the 2028 URP for the 20 percent most impaired days and will maintain visibility for the clearest days.

2028OTBa2 modeling results of 7.764 deciviews (dv) presented in Table 4-1 and Figure 4-10 (rounded to 7.76 dv and indicated by purple triangle in figure) show an improvement of 0.97 dv from the most impaired days baseline value of 8.73 dv for the Jarbidge WA using the USEPA default method. In order to remain below the URP glidepath in 2028, and meet natural visibility conditions by 2064, visibility conditions at Jarbidge WA must be below 8.2 dv. The 2028OTBa visibility projection of 7.764 dv is well below this, ensuring that visibility conditions at Jarbidge WA are on track to meet the national goal of natural visibility conditions.

During the 20 percent clearest days, 2028 visibility projections must not degrade beyond the baseline visibility conditions of 2.56. The 2028OTBa2 visibility projection for the clearest days satisfies this requirement at 1.724 dv (rounded to 1.72 and indicated by red triangle in figure), as shown in Table 4-1 and Figure 4-10.

TABLE 4-1

SUMMARY OF MODEL-PREDICTED VISIBILITY PROGRESS
IN 2028 AT JARBIDGE WILDERNESS AREA

Most Impaired Days (MID) Visibility Conditions (dv)				**Clearest Days** Visibility Conditions (dv)		
Baseline (2000-2004)	2028 URP Goal	2028 Model Projection	2028 Below Glidepath?	Baseline (2000-2004)	2028 Model Projection	2028 Below Baseline?
8.73	8.20	7.76	Yes	2.56	1.72	Yes

Figure 4-11 and Table 4-2 compare species-specific average annual light extinction between IMPROVE monitoring data observed from 2014 and 2018, or the representative baseline, and the modeled projection for 2028 (2028OTBa2).

All components show extinction reductions from the representative baseline conditions, except sea salt, which was held constant in emission inventories for the representative baseline period and the 2028 projection for the purposes of modeling.

FIGURE 4-10

MODEL PROJECTIONS IN HAZE INDEX
FOR JARB1 2028 MOST IMPAIRED DAYS

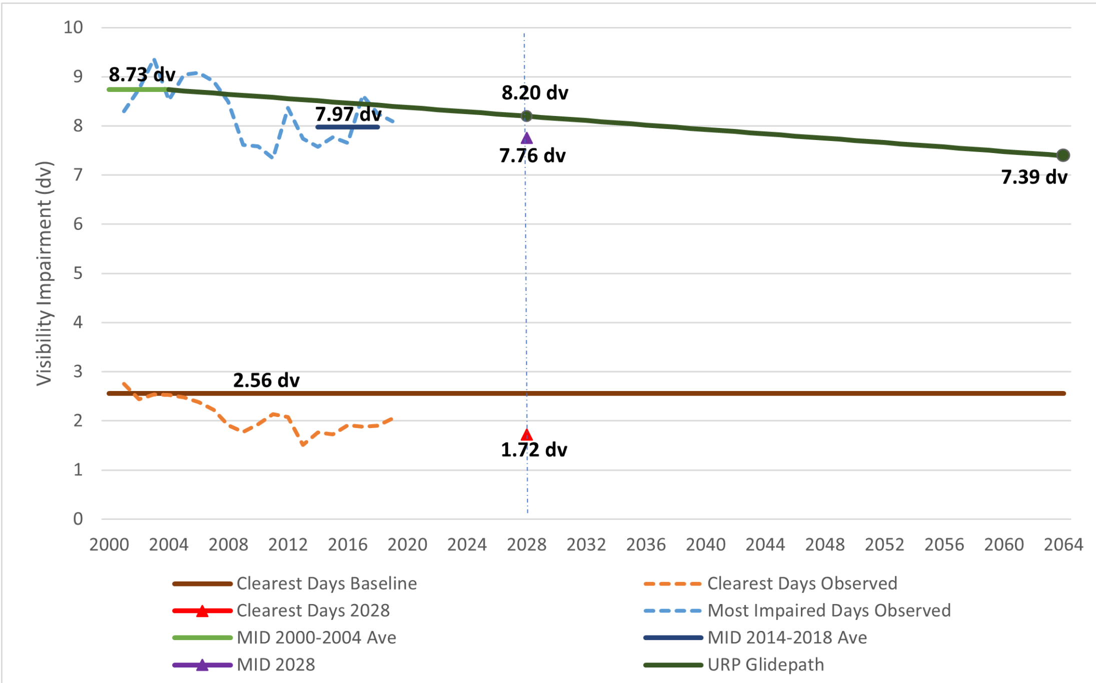


FIGURE 4-11

MODEL PROJECTIONS IN EXTINCTION
BY SPECIES FOR JARB1 MOST IMPAIRED DAYS

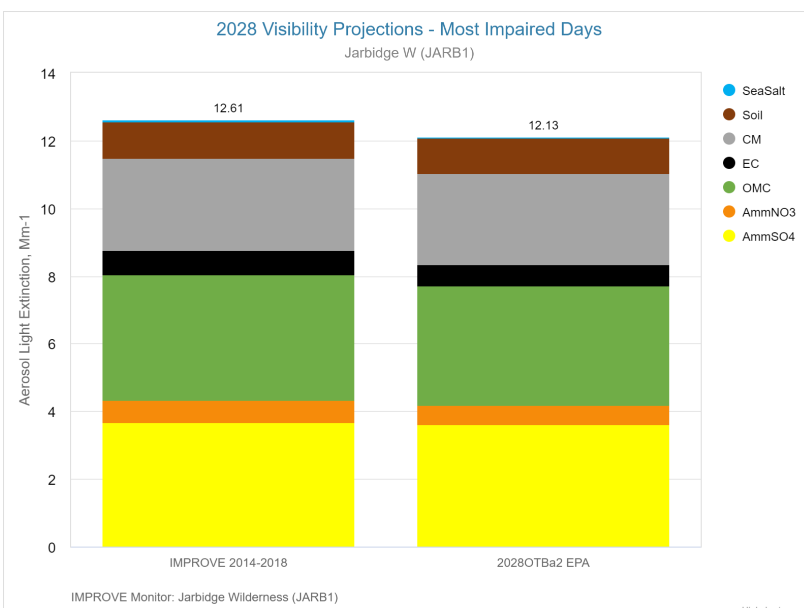


TABLE 4-2

SPECIES SUMMARY OF MODELED PROGRESS IN 2028 MID

	SeaSalt	Soil	CM	EC	OMC	Amm NO_3	Amm SO_4
IMPROVE 2014-2018	0.04	1.07	2.73	0.72	3.7	0.66	3.69
2028OTBa2	0.04	1.04	2.7	0.62	3.55	0.55	3.63
% Change from IMPROVE to 2028	0%	-2.8%	-1.1%	-13.9%	-4.1%	-16.7%	-1.6%

4.3 SOURCE APPORTIONMENT MODELING RESULTS

The CAMx photochemical model version 7.0 with the Particle Source Apportionment tool (PSAT) was applied at a regional level to separate U.S. anthropogenic contributions from those of fire, natural, and international anthropogenic contributions for a current period (2014-2018, RepBase2) and a future year, 2028OTBa2. CAMx with PSAT tracked gaseous and particle air emissions from sources through atmospheric dispersion, photochemical reactions, and transport to receptors (the 12-km modeling grid cell where the IMPROVE monitor is located). Aerosol concentrations at the receptor include the direct products of primary gaseous and particle emissions and secondary aerosol formation.

For the future year 2028OTBa2 model scenario, PSAT was applied to further define U.S. anthropogenic contributions to Ammonium NO_3 and Ammonium SO_4 aerosols at western Class I areas from each of 13 WESTAR-WRAP states and all other non-WRAP U.S. states combined. State contributions to Ammonium NO_3 and Ammonium SO_4 were subdivided into five anthropogenic source categories:

- electric generating units (EGU)
- oil and gas (area plus point sources) (OilGas)
- remaining point sources (non-EGU)
- Mobile onroad, nonroad, rail, and commercial marine vessels (CMV 1, 2, and 3) within 200 km of U.S. coast (Mobile)
- remaining anthropogenic sources (including Fugitive dust, Agriculture, Agricultural fire, residential wood combustion, and all remaining nonpoint sources)

For each Class I area, these results identify which source sectors and states are projected to have the greatest contributions in 2028OTBa2 to visibility impairment due Ammonium SO_4 and Ammonium NO_3. WRAP Source Apportionment methods are described in the run specification sheet for High-Level and Low-Level Source Apportionment Modeling using the RepBase2 and 2028OTBa2 modeling scenarios.[6]

---

6 https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/SourceApportionmentSpecifications_WRAP_RepBase2_and_2028OTBa2_High-LevelPMandO3_and_Low-Level_PM_andOptionalO3_Sept29_2020.pdf

4.3.1 Key Pollutants and Sources of Impairment

The analyses of the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitor data, as presented in Chapter Two, identify sulfates (SO4), organic matter carbon (OMC), and coarse mass (CM) as the three most significant components of annual average visibility impairment at the Jarbidge Wilderness Area for the most impaired days of the current 2014 through 2018 period, together accounting for approximately 80% of total light extinction.

For these days, NO_3 accounts for only five percent of the extinction, as shown on Table 4-3, modified from Table 2-7.

TABLE 4-3

MONITORED CONTRIBUTIONS TO AVERAGE ANNUAL
RECONSTRUCTED EXTINCTION FOR CURRENT PERIOD

	OMC Extinction	CM Extinction	SO_4 Extinction	Soil Extinction	EC Extinction	NO_3 Extinction	Sea Salt Extinction
20% Most Impaired Days							
Average	**29.3%**	**21.6%**	**29.3%**	**8.5%**	**5.7%**	**5.2%**	**0.3%**
20% Clearest Days							
Average	**11.1%**	**6.7%**	**22.5%**	**2.1%**	**3.2%**	**5.6%**	**1.2%**

Compilation and analyses of baseline (2014-2018) and 2028 emissions inventories, presented in Chapter Three, demonstrate that nearly three quarters of Nevada's total emissions originate from natural (i.e., non-anthropogenic) sources, see Table 3-2. Sulfur dioxide (SO_2), ammonia (NH_3), and particulate matter ($PM_{2.5}$ and PM_{10}) are the only pollutants whose 2028 emissions are dominated by anthropogenic sources, although nitrogen oxides (NO_x) and carbon monoxide (CO) 2028 emissions are sub-equally divided between natural and anthropogenic sources. Note that the existing 2028 emission inventories do not include reductions resulting from reasonable progress determinations made from the four-factor analyses.

Analyses of the *projected 2028* emissions data have led to the following conclusions:

- The vast majority of volatile organic compounds (VOC) emissions are from biogenic sources (92 percent).
- Emissions of PM_{10} are dominated by fugitive dust emissions at 79 percent.
- Nonpoint sources account for 42 percent and point sources (EGU and Non-EGU) account for 47 percent of emissions of SO_2, a component of monitored species SO_4.
- Emissions of $PM_{2.5}$ are predominantly fugitive dust (50 percent), however, wildfire emissions (23 percent) are also a significant contributor.
- Lightning NO_x accounts for the majority (53 percent) of NO_x emissions, a component of monitored species NO_3; although mobile sources (16 percent) and biogenic emissions (11 percent) are also a significant contributors.
- Emissions of ammonia (NH_3) are dominated by agricultural emissions (83 percent)

Visibility modeling projections, shown in Figure 4-12 and Figure 4-13, indicate the relative contribution to 2028 visibility impairment at the Jarbidge WA for each visibility impairing species in units of inverse megameters (Mm-1). This graph shows an extinction reduction for each species by the end of the second planning period, except Sea Salt, Soil, and CM. CM and Soil emissions were held constant from the baseline to 2028 and Sea Salt is not an important component of extinction at JARB1. As noted above, VOC, CO, and NO_x emissions are dominated by natural sources. Jarbidge's three most significant components of annual average visibility impairment are SO_4, OMC, and CM. In Figure 4-13, SO_4 (dark blue line) and OMC (light blue line) both show a downward trend in light extinction. CM does not, as emissions were held constant.

The SO_4 and NO_3 source apportionment modeling identifies the relative concentration due to SO_x and NO_x emissions by source area and source category, as shown in Figure 4-14. Figure 4-14 shows the dominating effect of uncontrollable emissions from international anthropogenic and natural sources for SO_4 concentrations at the Jarbidge WA, accounting for more than 90 percent of total light extinction.

Figure 4-14 shows contributions to NO_3 concentrations at the Jarbidge WA is NO_x emissions is split evenly among international anthropogenic, US anthropogenic, and natural sources. Total NO_3 concentration is much less than total SO_4 concentration

FIGURE 4-12

MODEL PROJECTED EXTINCTION
BY SPECIES FOR JARB1 2028 MOST IMPAIRED DAYS WITH HINDCAST

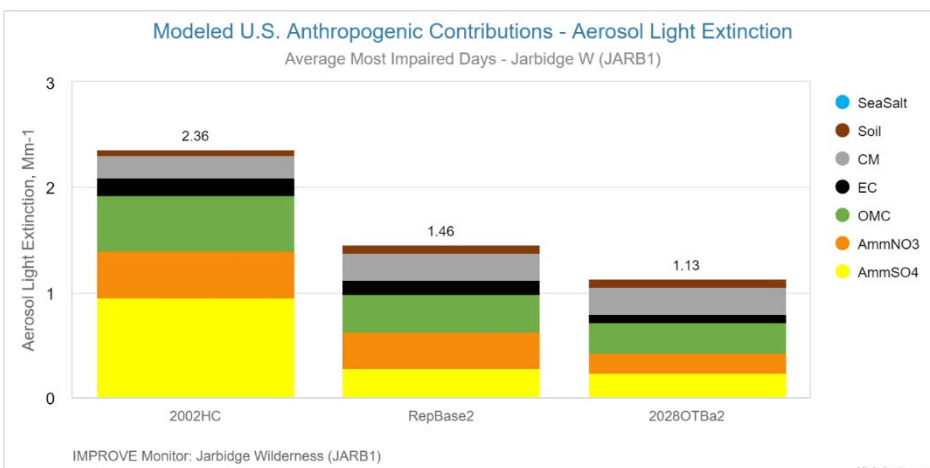


FIGURE 4-13

MODELED VISIBILITY EXTINCTION PROGRESS
BY SPECIES FOR JARB1 2028 MOST IMPAIRED DAYS

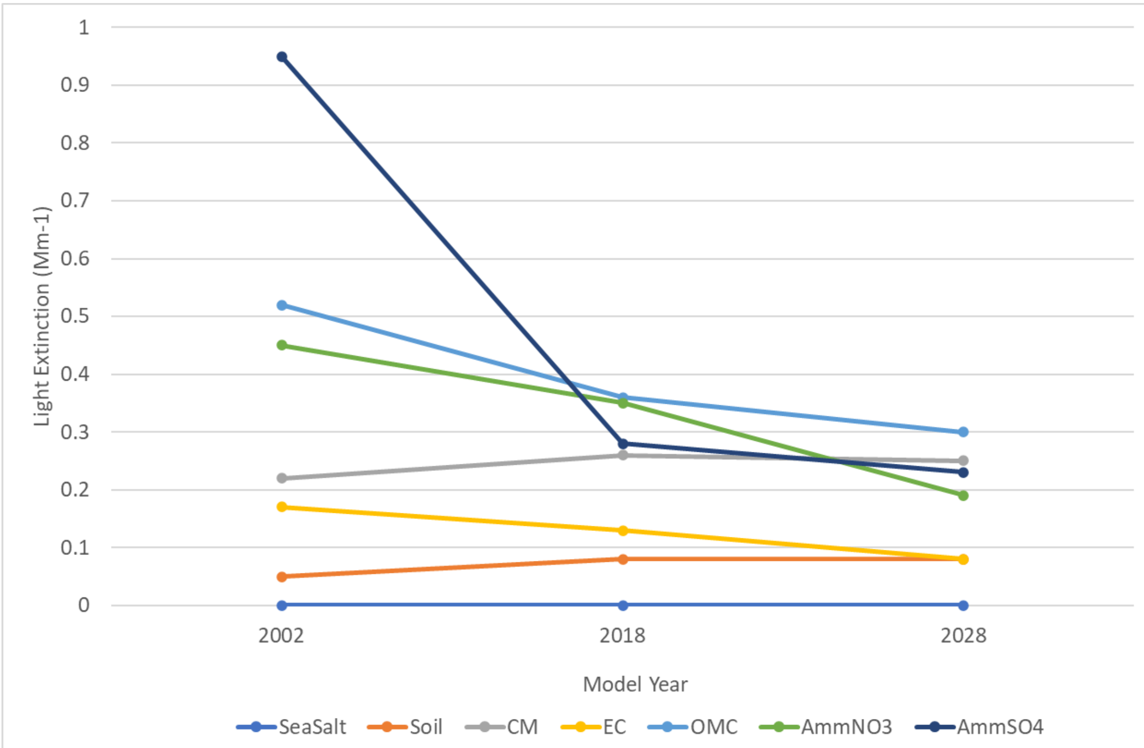
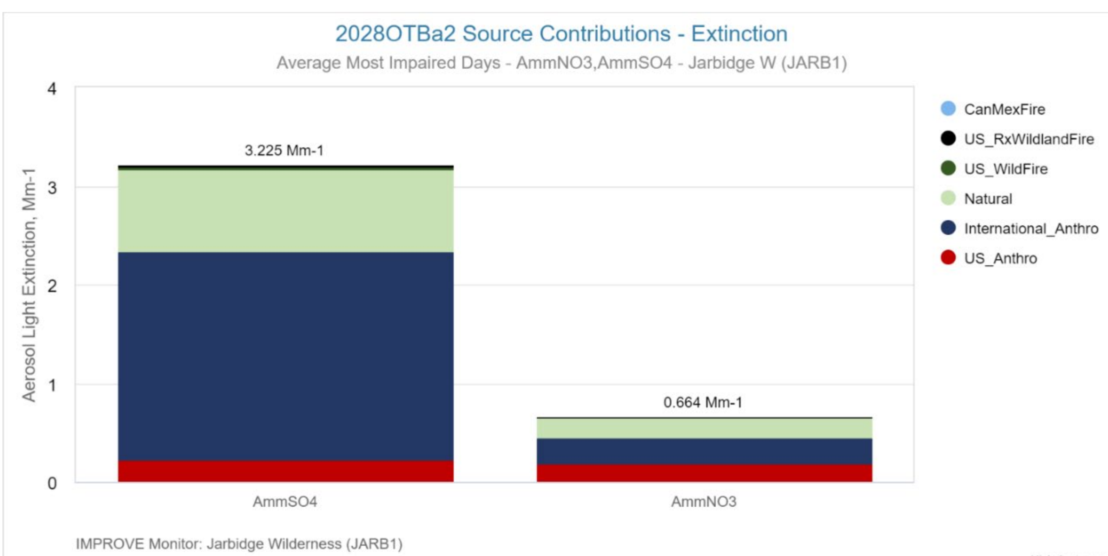


FIGURE 4-14

SULFATE AND NITRATE PSAT SOURCE REGION BAR
CHART FOR MOST IMPAIRED DAYS 2028



4.3.2 Sulfate Source Apportionment for Jarbidge Wilderness Area

Figure 4-15 displays the 2028 most impaired days particulate sulfate concentrations impacting the JARB1 monitor due to emissions from WRAP states. The chart provides details on the relative source contribution for each WRAP state in 2028. The data indicate the overall SO_2 emission sources for the most impaired days are primarily from the states of California, Idaho, Oregon and Washington. For all these states, contributions to sulfate are primarily from Non-EGU and industrial sources. Remaining anthropogenic source sectors outside of point and mobile sources is the next largest contributor among these states. Nevada's EGU sector is also one of the most significant contributors to ammonium sulfate extinction at Jarbidge Wilderness Area.

Figure 4-16 shows the contributions to sulfate concentration from all modeled source areas for the most impaired days of 2028 at the JARB1 monitor. This chart shows that emissions from international sources, including non-US fire, is the most significant contributor to light extinction at Jarbidge Wilderness area at about 89%.

FIGURE 4-15

SULFATE PSAT SOURCE REGION BAR
CHART FOR MOST IMPAIRED DAYS AT JARBIDGE IN 2028

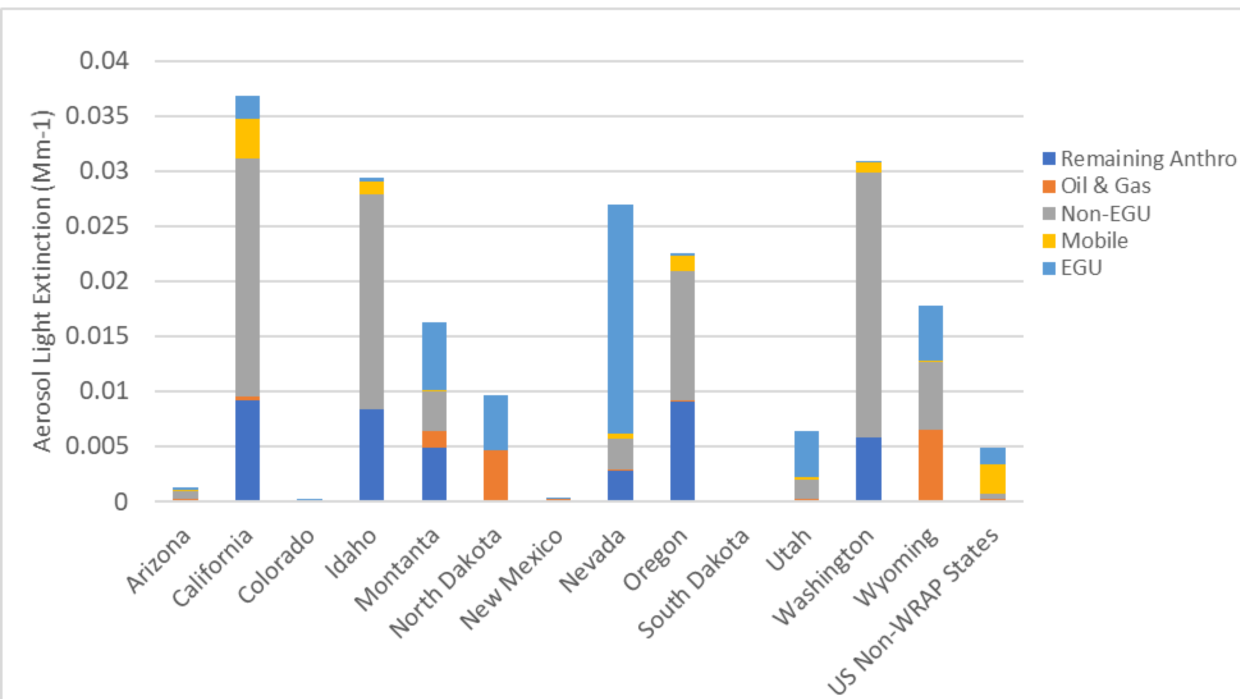
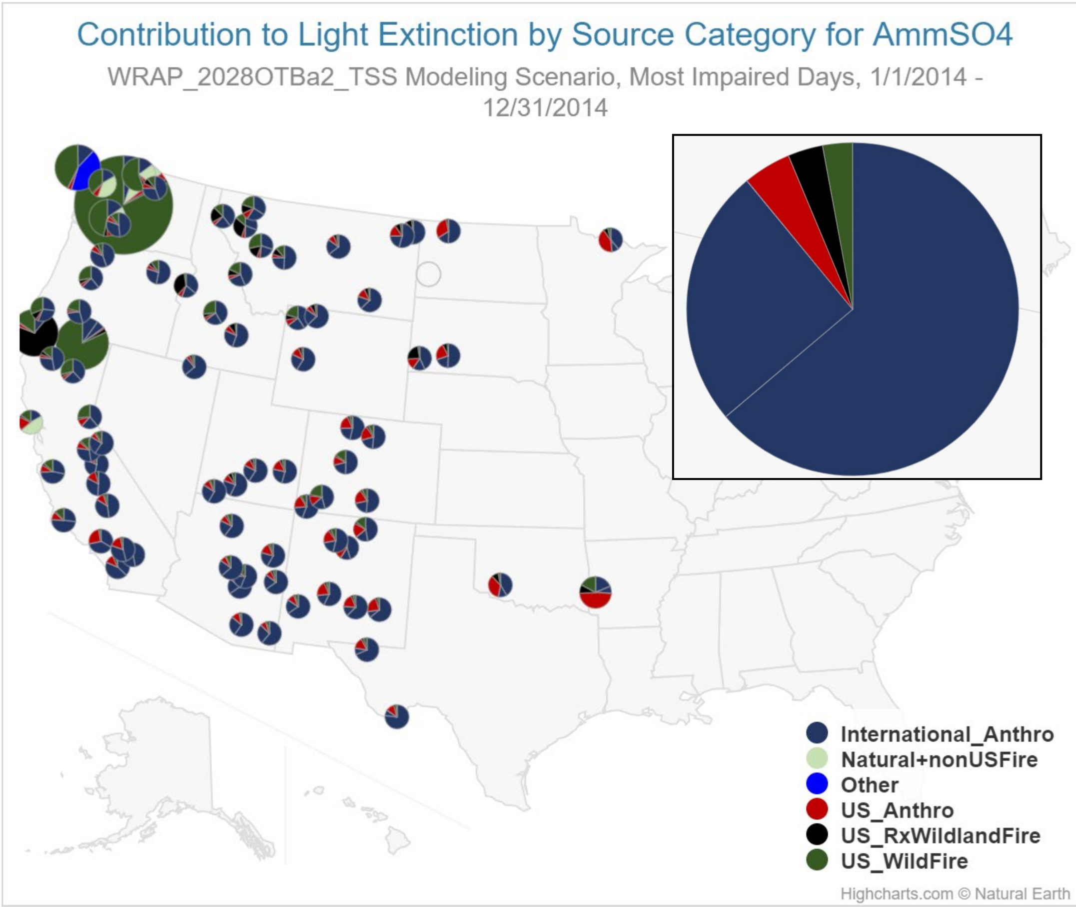


FIGURE 4-16

SULFATE PSAT REGIONAL PIE CHART FOR MOST IMPAIRED DAYS



* Dark blue includes international anthro and natural and non-US fire in pie chart
*Inset: Jarbidge WA $AmmSO_4$ pie chart

4.3.3 Nitrate Source Apportionment for Jarbidge Wilderness Area

Figure 4-17 displays the particulate nitrate concentrations for 2028 most impaired days for WRAP source areas at the JARB1 monitor. The chart provides details on the relative source contribution of each WRAP state during 2028. The data indicate the dominant WRAP source area contributions for the most impaired days are from California, Idaho, Oregon, and Washington. Mobile source emissions are the dominant source category for NO_x emissions, followed by Non-EGU and area sources.

FIGURE 4-17

NITRATE PSAT SOURCE REGION BAR
CHART FOR MOST IMPAIRED DAYS AT JARBIDGE IN 2028

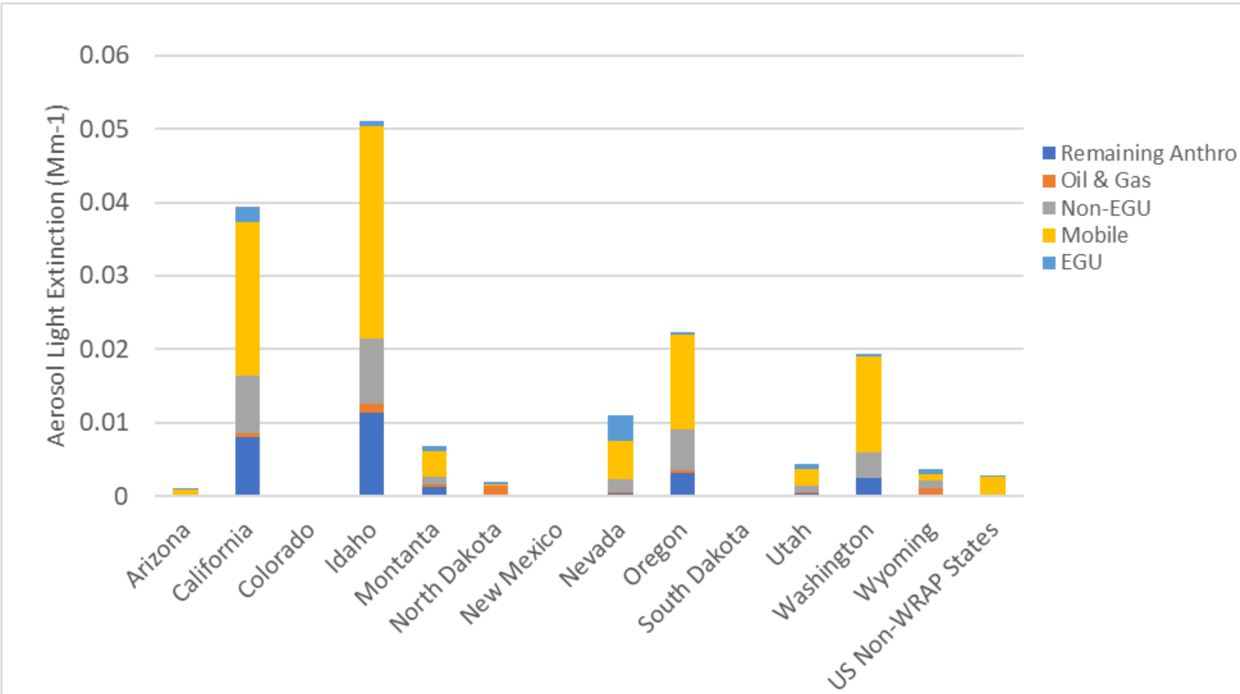
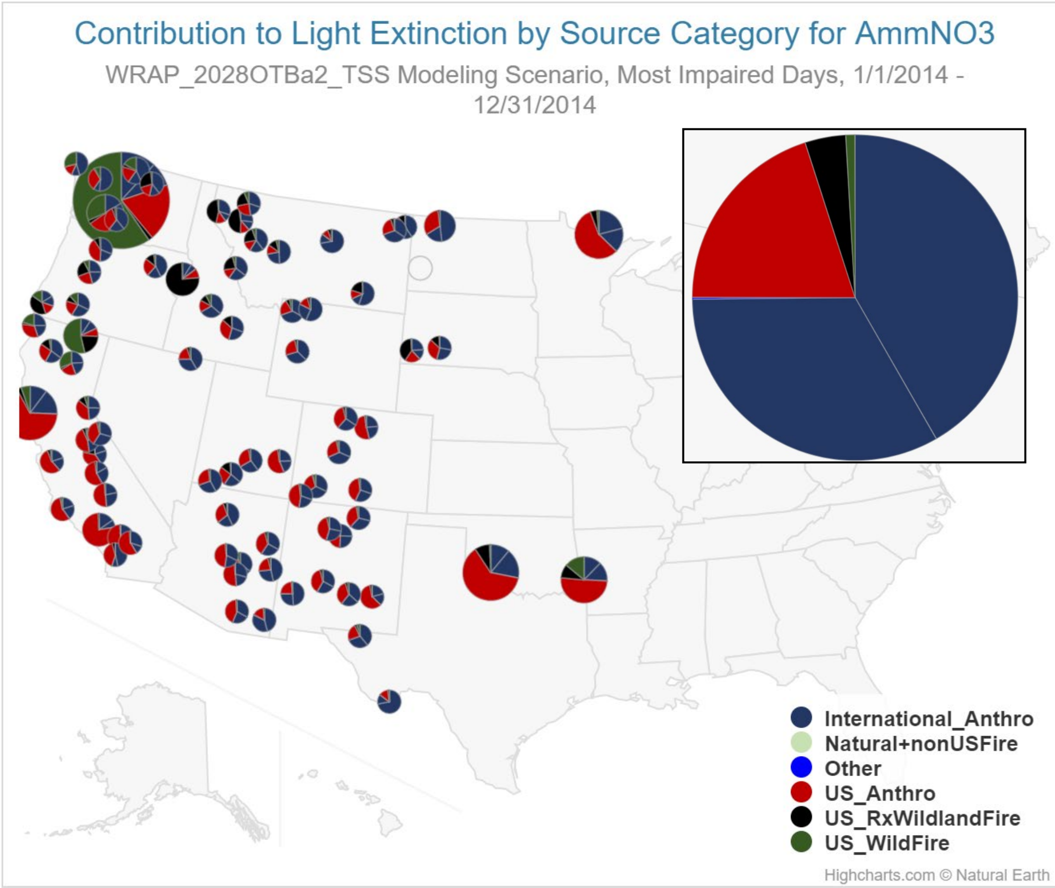


Figure 4-18 shows the contributions to nitrate concentration from all modeled source areas for the most impaired days of 2028 at the JARB1 monitor. This chart shows that emissions from international sources, including non-US fire, is the most significant contributor to light extinction at Jarbidge Wilderness area at about 75%.

FIGURE 4-18

NITRATE PSAT REGIONAL PIE CHART FOR MOST IMPAIRED DAYS



*Dark blue includes international anthro and natural and non-US fire in pie chart
*Inset: Jarbidge WA $AmmNO_3$ pie chart

4.3.4 Source Apportionment for Other Class I Areas

The PSAT source apportionment modeling results were evaluated to determine which Class I areas in adjacent states might be affected by emissions from Nevada sources. Table 4-4 presents the results of this evaluation for sulfate and nitrate extinction. The table identifies the rank and percentage of the total modeled concentration due to SO_2 and NOx emissions from sources within Nevada to the IMPROVE monitors representing all Class I areas in the five adjacent states. The rank and percentage contribution is based on contributions from all modeled source areas (13 continental western WRAP states and US Non-WRAP). The bolded values are the highest percentage contribution to visibility impairment at Class I areas in each of the five adjacent states due to emissions from Nevada sources for the most impaired days projected for 2028.

TABLE 4-4

NEVADA'S SULFATE AND NITRATE EXTINCTION CONTRIBUTION TO
CLASS I AREAS OUTSIDE OF NEVADA

IMPROVE Site Code	IMPROVE Site Name	Extinction Contribution due to Nevada Emissions			
		Ammonium Sulfate		Ammonium Nitrate	
		Impact	Rank	Impact	Rank
Arizona					
BALD1	Mount Baldy	0.69%	6	0.66%	5
CHIR1	Chiricahua	1.67%	6	0.99%	6
GRCA2	Grand Canyon	3.58%	5	**2.15%**	6
IKBA1	Ike's Backbone	**4.24%**	5	1.28%	5
PEFO1	Petrified Forest	0.88%	7	0.64%	7
SAGU1	Saguaro	2.35%	4	1.62%	3
SIAN1	Sierra Ancha	3.06%	5	0.83%	4
TONT1	Tonto	3.16%	5	1.53%	5
California					
AGTI1	Agua Tibia	1.53%	3	0.42%	4
BLIS1	Desolation	**6.17%**	2	**11.44%**	2
DOME1	Dome Land	1.60%	3	0.56%	3
HOOV1	Hoover	2.40%	2	1.65%	2
JOSH1	Joshua Tree	1.63%	3	0.43%	3
KAIS1	Kaiser	1.57%	3	0.94%	3
LABE1	Lava Beds	3.51%	4	0.94%	5
LAVO1	Lassen Volcanic	1.87%	5	0.65%	5
PINN1	Pinnacles	1.13%	5	0.93%	4
PORE1	Point Reyes	0.60%	5	0.63%	5
RAFA1	San Rafael	2.03%	4	0.88%	4
REDW1	Redwood	0.13%	5	0.08%	5
SAGA1	San Gabriel	0.82%	4	0.29%	4
SAGO1	San Gorgonio	1.46%	3	0.43%	4
SEQU1	Sequoia	2.05%	3	0.96%	2
TRIN1	Trinity	1.19%	5	0.48%	5
YOSE1	Yosemite	1.93%	4	0.82%	3
Idaho					
CRMO1	Craters of the Moon	**10.78%**	3	**4.91%**	4
SAWT1	Sawtooth	6.86%	5	2.52%	7
SULA1	Sula Peak	2.53%	6	1.51%	9
Oregon					
CRLA1	Crater Lake	0.94%	5	0.71%	5
HECA1	Hells Canyon	**5.13%**	5	**2.35%**	5
KALM1	Kalmiopsis	0.70%	5	0.56%	6
MOHO1	Mount Hood	0.20%	7	0.15%	7
STAR1	Starkey	2.47%	7	0.89%	7
THSI1	Three Sisters	0.91%	5	0.43%	5
Utah					
BRCA1	Bryce Canyon	5.11%	7	6.02%	5
CANY1	Canyonlands	3.06%	8	1.53%	7
CAPI1	Capitol Reef	5.09%	7	4.37%	8
ZICA1	Zion Canyon	**8.72%**	5	**11.46%**	3

Nevada source-sector contributions identified for ammonium sulfate and ammonium nitrate extinction at out-of-state CIAs (Grand Canyon, Ike's Backbone, Desolation Wilderness, Craters of the Moon, Hells Canyon, and Zion Canyon) were identified through source apportionment modeling during the most impaired days in 2028. These CIA's were analyzed since they were identified as the CIA in each neighboring state most impacted by sulfate or nitrate extinction contributions from Nevada (bold values in Table 4-4). The anthropogenic source sectors considered are mobile, EGU, non-EGU, oil and gas, and remaining anthropogenic sources in Nevada. Total contributions from Nevada are compared to total sulfate light extinction at each CIA to determine NV's anthropogenic contribution to total sulfate (Table 4-5) and nitrate extinction (Table 4-6) by percent.

The highest contribution from Nevada anthropogenic sources to an out-of-state CIA's sulfate extinction in 2028 is Crater's of the Moon at 1.15%. Among all evaluated CIA's, EGU, non-EGU, and remaining anthropogenic sources tend to be the largest contributors to sulfate extinction. The highest contribution to an out-of-state CIA's nitrate extinction in 2028 is Desolation Wilderness at 6.16%. Among all evaluated CIA's, the mobile source sector is generally the largest contributor to nitrate extinction.

TABLE 4-5

NEVADA'S SULFATE EXTINCTION CONTRIBUTION TO
CLASS I AREAS OUTSIDE OF NEVADA BY SOURCE SECTOR

		Nevada Source Sector Impacts on Out-of-State CIA Sulfate Extinction (Mm-1)							
State	**CIA**	**Mobile**	**EGU**	**Non-EGU**	**Oil & Gas**	**Remaining Anthro**	**Total NV**	**Total Sulfate Light Extinction at CIA**	**% Anthro NV**
AZ	**Ike's Backbone (IKBA1)**	0.00008	0.00037	0.00043	0.00000	0.00139	**0.00227**	5.03	**0.05%**
CA	**Desolation Wilderness (BLIS1)**	0.00740	0.00577	0.00725	0.00007	0.01410	**0.03459**	4.47	**0.77%**
ID	**Craters of the Moon (CRMO1)**	0.00055	0.02662	0.00460	0.00008	0.00656	**0.03841**	3.34	**1.15%**
OR	**Hells Canyon (HECA1)**	0.00041	0.01615	0.00317	0.00006	0.00366	**0.02345**	4.44	**0.53%**
UT	**Zion Canyon (ZICA1)**	0.00099	0.00414	0.00480	0.00006	0.01482	**0.02481**	4.18	**0.59%**

TABLE 4-6

NEVADA'S NITRATE EXTINCTION CONTRIBUTION TO
CLASS I AREAS OUTSIDE OF NEVADA BY SOURCE SECTOR

		Nevada Source Sector Impacts on Out-of-State CIA Nitrate Extinction (Mm-1)							
State	**CIA**	**Mobile**	**EGU**	**Non-EGU**	**Oil & Gas**	**Remaining Anthro**	**Total NV**	**Total Sulfate Light Extinction at CIA**	**% Anthro NV**
AZ	**Grand Canyon (GRCA1)**	0.00392	0.00053	0.0015	0.00003	0.00078	**0.00676**	0.83	**0.81%**
CA	**Desolation Wilderness (BLIS1)**	0.06265	0.00222	0.01155	0.00006	0.00794	**0.08442**	1.37	**6.16%**
ID	**Craters of the Moon (CRMO1)**	0.01967	0.00598	0.0069	0.00018	0.00258	**0.03531**	4	**0.88%**
OR	**Hells Canyon (HECA1)**	0.01233	0.00494	0.00411	0.0002	0.00139	**0.02297**	9.77	**0.24%**
UT	**Zion Canyon (ZICA1)**	0.01262	0.00166	0.00577	0.00011	0.00361	**0.02377**	0.88	**2.70%**

4.4 WEIGHTED EMISSIONS POTENTIAL ANALYSES RESULTS

The Weighted Emissions Potential (WEP) tool is an analysis technique that identifies the predominant emission source regions contributing haze-forming pollutants at each Class I area based on 5 years of historical meteorology during the most impaired days, as described in Chapter One.

The WEP analysis results in two graphical displays of the data: WEP maps of extinction-weighted residence times (EWRT) for visibility impairing pollutant species and normalized, weighted emissions potential (WEP). The maps show the location of the Jarbidge WA with a green star. Extinction weighted residence time shows different colors for different regions to indicate the contribution percentage of pollutant species observed at Jarbidge Wilderness area.

For WEP maps, the areas shaded in different colors identify those 36 km grid cells with the potential of contributing emissions to JARB1 for the most impaired days in 2028. Geographical regions and individual grid cells with greater potential to impact the Jarbidge WA are easily distinguished in the maps by referencing the color scale for the grid cells, while the white areas denote those grid cells with negligible emission potential.

4.4.1 Nitrogen Oxides – Regional WEP Analysis for 2028 Most impaired days

Examination of Figures 4-19 and 4-20 shows the point source contributions from the industrialized portions of northern Nevada and along the Snake River Plain of Idaho, as well as more distant areas in southern Nevada and portions of California, including the Bay Area, Central Valley and Los Angeles area, to 2028 NO_x concentrations at JARB1. These figures also show contributions from the main transportation corridors and population centers along I-80 in Nevada and Utah, I-84 in Utah, Idaho, and Oregon, and I-5 in California to NO_x emissions at JARB1.

The WEP illustrates that Idaho has point sources that yield up to five to ten percent (maroon grid cells) of total anthropogenic NOx emissions of the region that contribute to ammonium nitrate extinction at Jarbidge, while one Oregon source reaches up to three to five percent (orange grid cell), and the Bay Area of California and Northern Nevada have sources that reach up to one to three percent (lime green grid cells).

FIGURE 4-19

REGIONAL NITRATE EWRT FOR 2028 MOST IMPAIRED DAYS

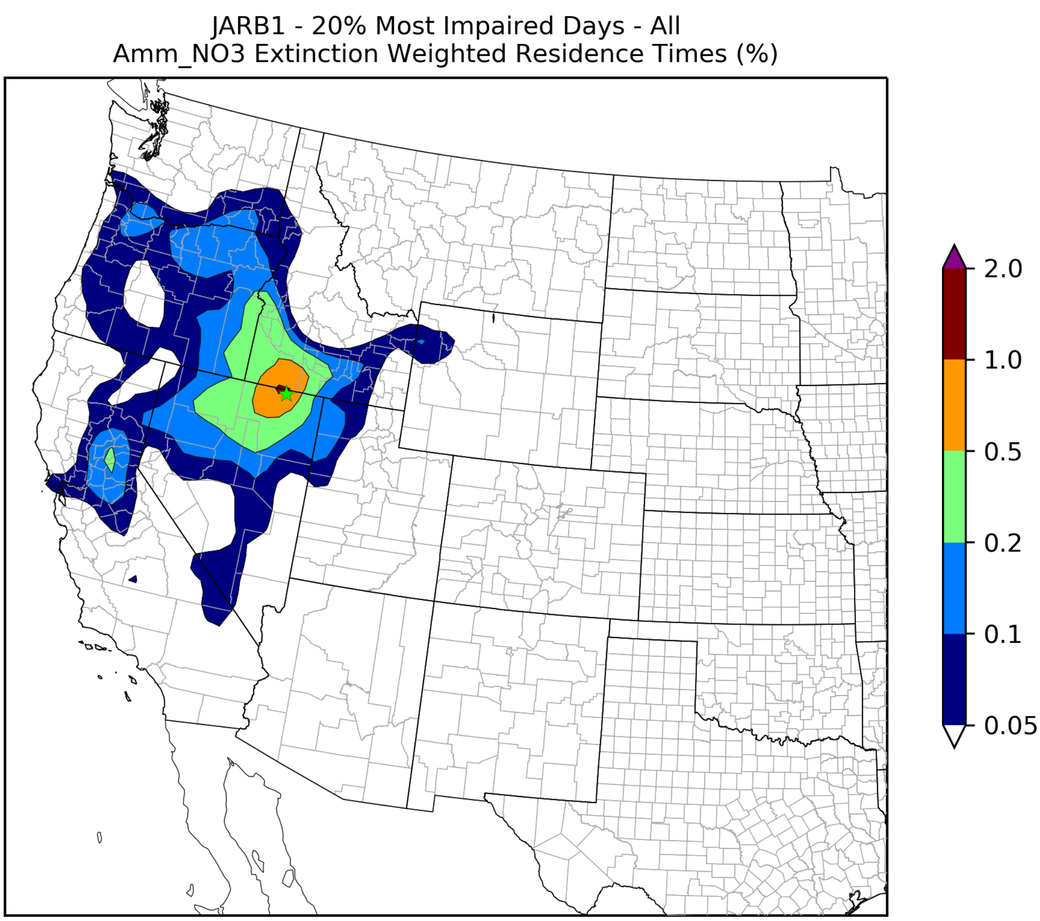
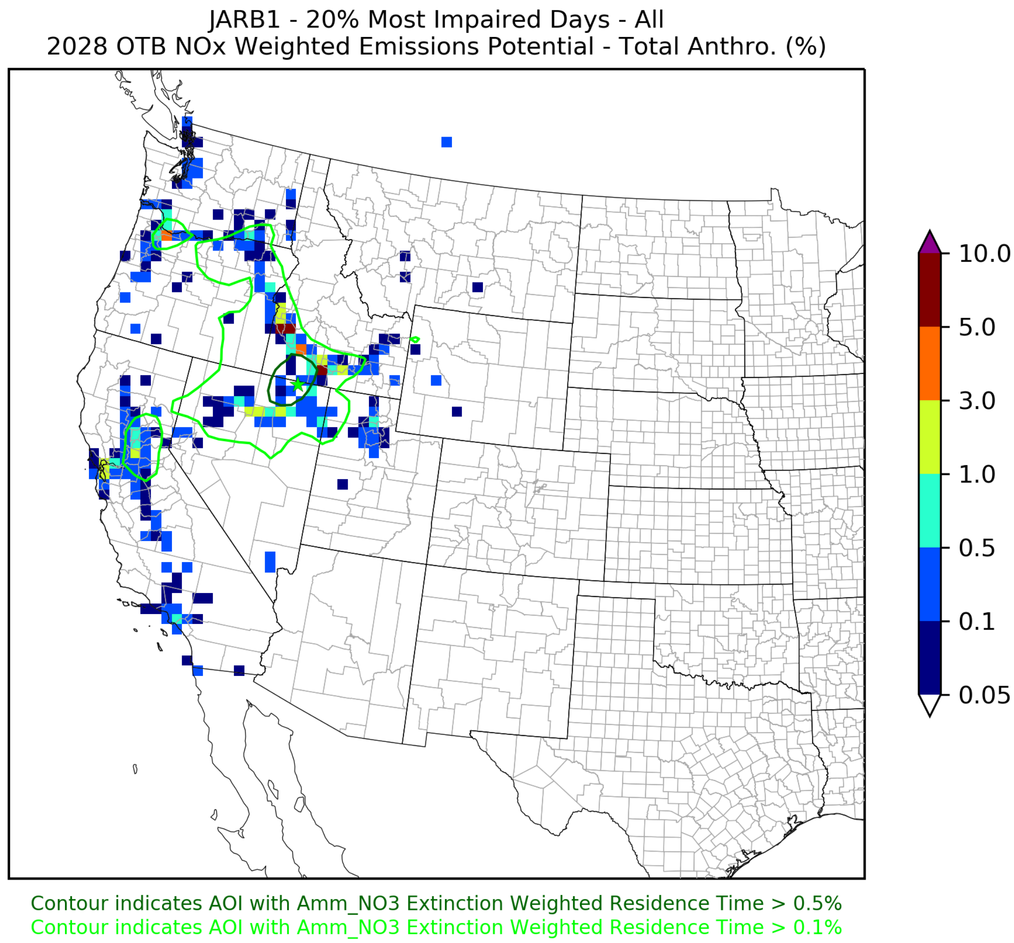


FIGURE 4-20

REGIONAL NO_x WEP FOR 2028 MOST IMPAIRED DAYS



4.4.2 Sulfur Oxides – Regional WEP Analysis for 2028 Most impaired days

Figure 4-21 shows the normalized regional contributions to residence time- and distance-weighted SO_2 emissions for JARB1. Examination of Figures 4-21 and 4-22 shows the large point source contributions from the industrialized portions of northeastern Nevada and along the Snake River Plain of Idaho, as well as more distant areas in the Bay Area of California and Northwest Oregon to 2028 SO_2 concentrations at JARB1.

The WEP illustrates that Idaho has two point sources that yield ten percent and above (purple grid cells) of total anthropogenic SOx emissions of the region that contribute to ammonium sulfate extinction at Jarbidge, while Nevada has one point source that yields ten percent and above, and California has one point source that yields three to five percent (orange grid cell) in the Bay Area. Washington, Oregon, and Utah have at least one point source that yields one to three percent (lime green grid cells).

FIGURE 4-21

REGIONAL SULFATE EWRT FOR 2028 MOST IMPAIRED DAYS

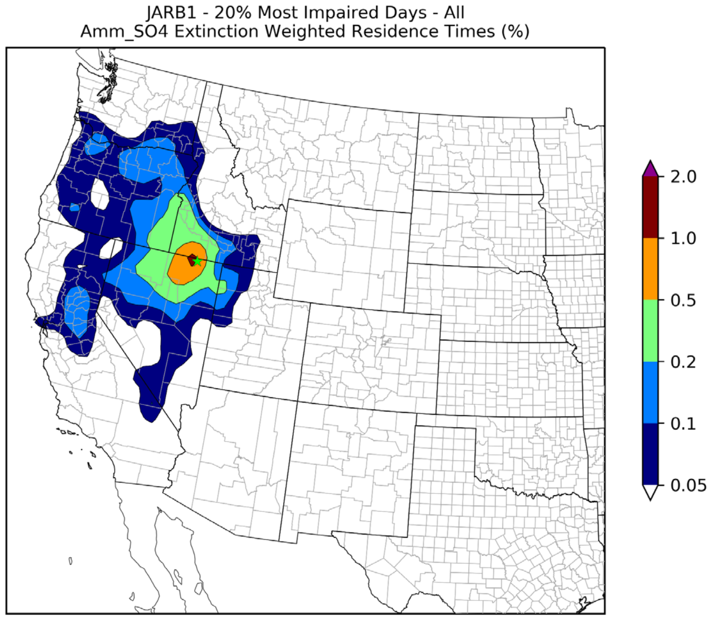
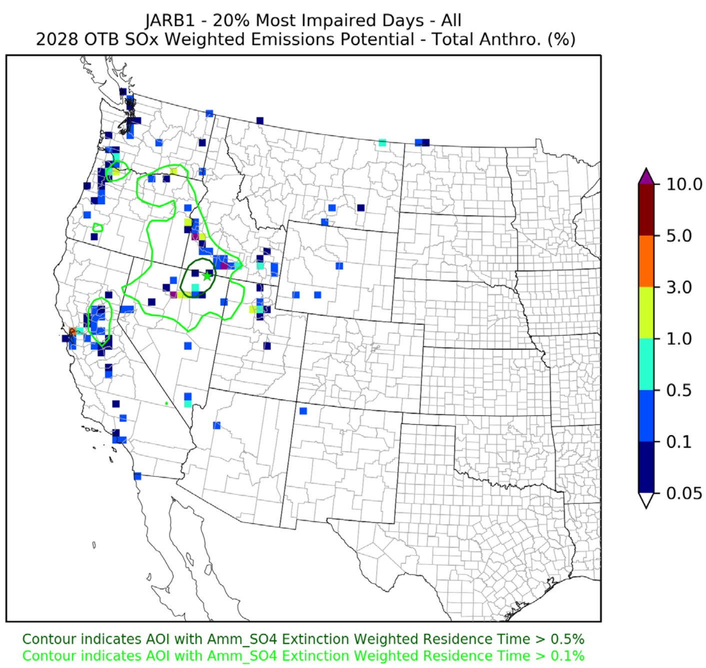


FIGURE 4-22

REGIONAL SO_X WEP FOR 2028 MOST IMPAIRED DAYS



4.4.3 Primary Organic Aerosol – Regional WEP Analysis for 2028 Most impaired days

Examination of Figures 4-23 and 4-24 shows the point source contributions from the industrialized portions of northern Nevada and along the Snake River Plain of Idaho, as well as more distant areas in southern Nevada and portions of California, including the Bay Area, Central Valley and Los Angeles area to 2028 NO_x concentration at JARB1. These figures also show contributions from the main transportation corridors and population centers along I-80 in Nevada and Utah, I-84 in Utah, Idaho, and Oregon, and I-5 in California to NO_x emissions at JARB1.

The WEP results indicate that Idaho sources are the largest contributors of organic aerosols impacting extinction at Jarbidge Wilderness Area, with several sources yielding between one percent and above ten percent. Oregon has one point source yielding three to five percent (orange) and California and Nevada both have one point source contributing one to three percent (lime green).

FIGURE 4-23

REGIONAL POA EWRT FOR 2028 MOST IMPAIRED DAYS

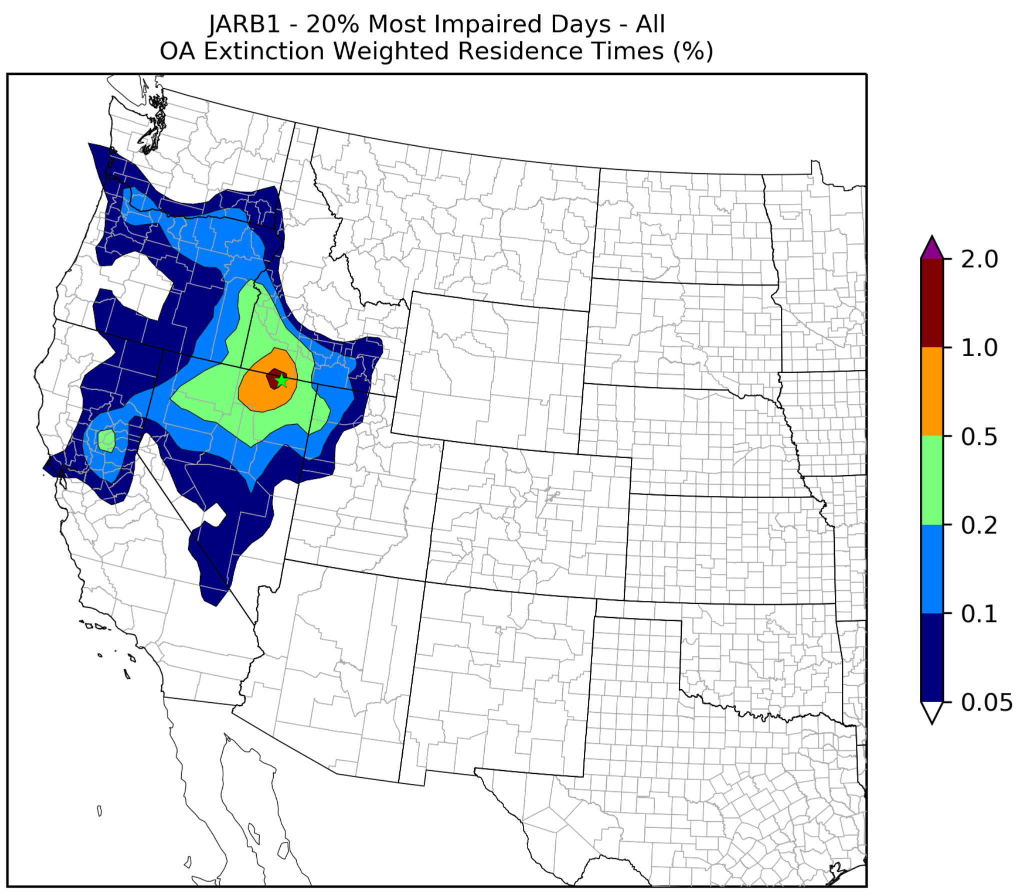
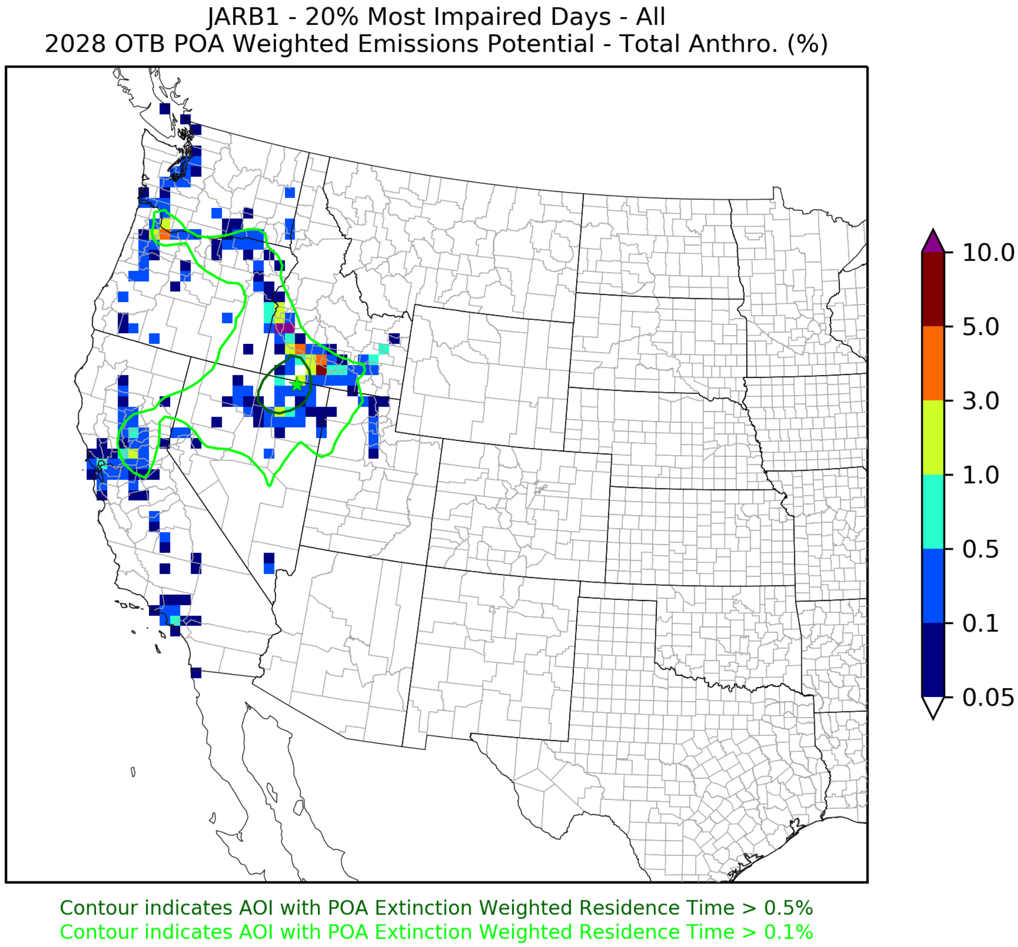


FIGURE 4-24

REGIONAL POA WEP FOR 2028 MOST IMPAIRED DAYS



4.4.4 Elemental Carbon – Regional WEP Analysis for 2028 Most impaired days

Figure 4-25 shows the normalized regional contributions to residence time- and distance-weighted primary EC emissions for JARB1. The WEP bar charts, shown as Figure 4-26, display normalized (unitless), residence time- and distance-weighted annual primary EC emissions values, by emissions source region. The contribution distribution shown by EC is very similar to that shown by OC. Examination of Figures 4-25 and 4-26 shows the large, natural fire-source contributions from diffuse areas of California, Idaho, northern Nevada, Oregon, Utah and Washington to 2028 EC concentrations at JARB1. These figures also show the contribution of area and off-road mobile sources from population centers along the Snake River Plain of Idaho, the Central Valley and Bay Area of California, the Portland area of Oregon and the Seattle area of Washington.

The WEP results indicate that Idaho sources are the largest contributors of organic aerosols impacting extinction at Jarbidge Wilderness Area, with several sources yielding between one percent and ten percent. Oregon has one point source yielding three to five percent (orange) and California and Nevada both have at least one point source contributing one to three percent (lime green).

FIGURE 4-25

REGIONAL EC EWRT FOR 2028 MOST IMPAIRED DAYS

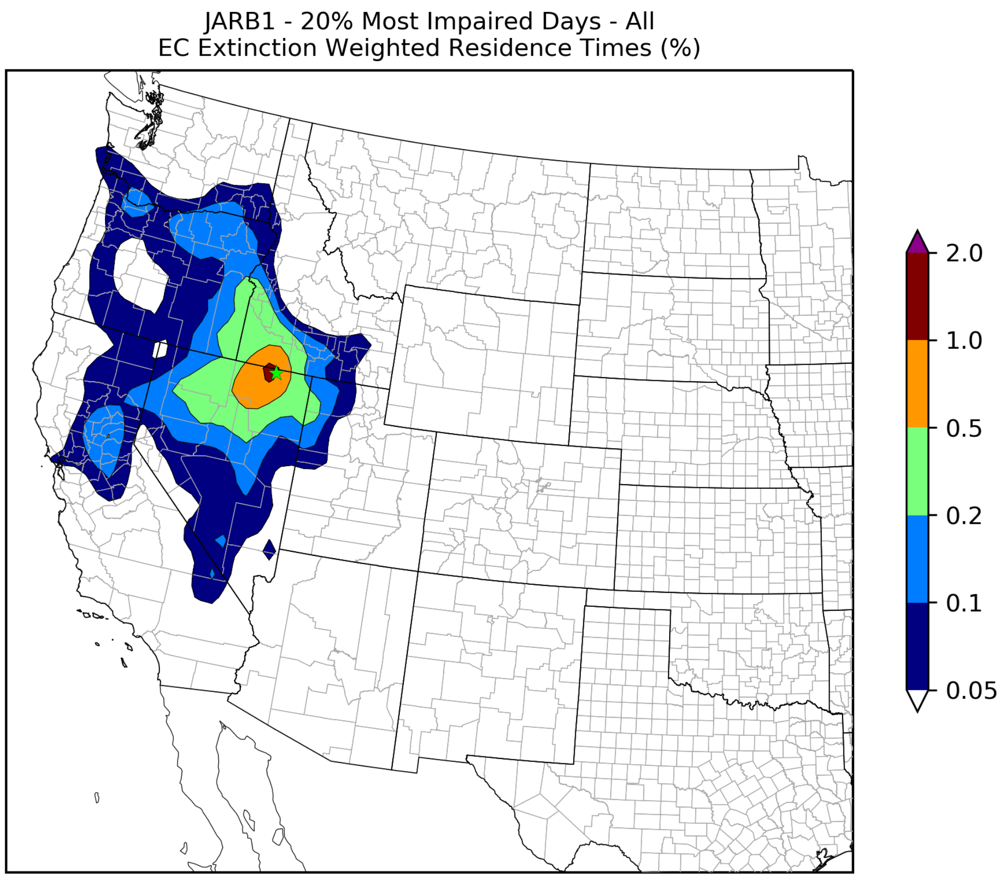
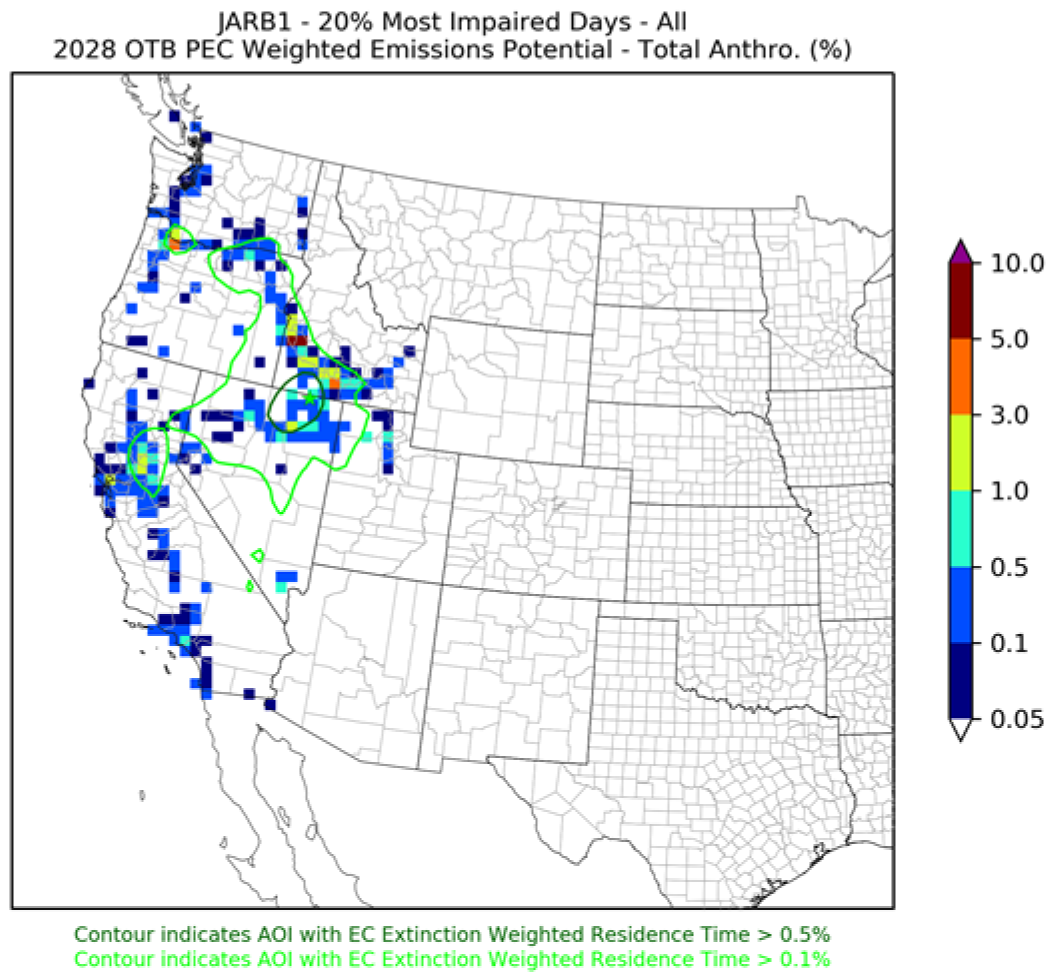


FIGURE 4-26

REGIONAL EC WEP FOR 2028 MOST IMPAIRED DAYS



4.5 VISIBILITY AND SOURCE APPORTIONMENT MODELING SUMMARY

Results of the CAMx visibility modeling forecasts indicate the Jarbidge WA will meet the URP for 2028 for the most impaired days with no degradation of clearest days.

Results of the PSAT source apportionment modeling identify the source areas contributing to sulfate and nitrate extinction at the JARB1 monitor. Figure 4-27 lists the six source areas and the corresponding contribution of SO_2 and NO_x to JARB1 based on the source apportionment modeling. The area with the greatest sulfate contribution is international anthropogenic emissions, followed by natural emissions. US anthropogenic emissions is not a significant contributor of sulfate at the Jarbidge WA.

For nitrate extinction at Jarbidge WA, contributions are similarly split among US anthropogenic, international anthropogenic, and natural emissions.

FIGURE 4-27

SUMMARY OF 2028 MODEL RESULTS FOR JARBIDGE WILDERNESS AREA

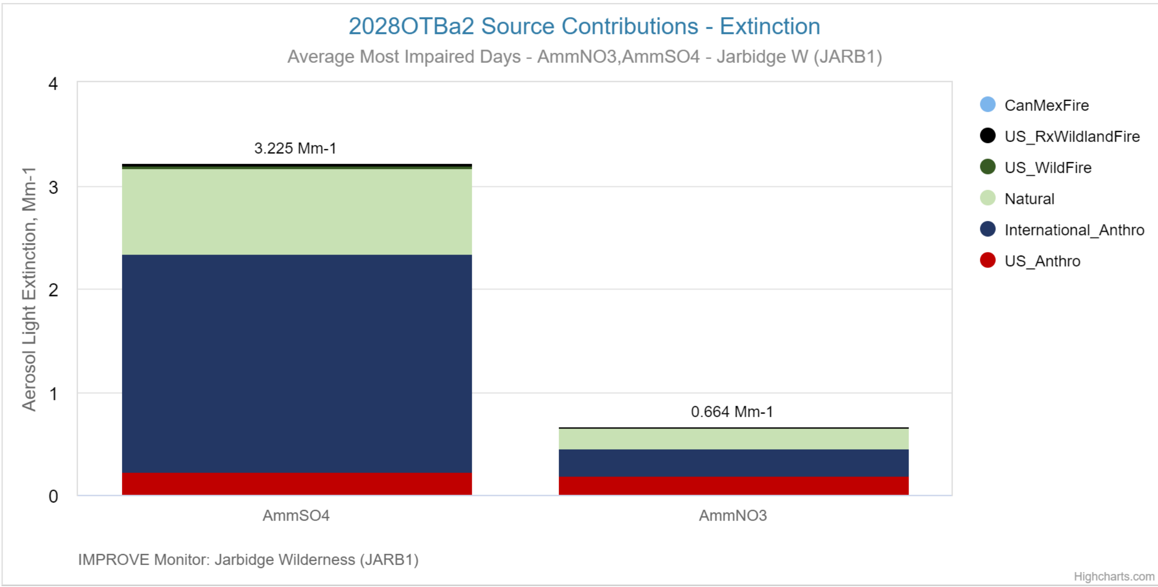


Table 4-7 lists the 2028 modeled particulate sulfate and nitrate concentrations at the Jarbidge WA for the most impaired days. The 2028 PSAT modeling forecasts that US anthropogenic emissions will only contribute 7.16% of total sulfate extinction at Jarbidge WA, and only 28.31% of total nitrate extinction.

TABLE 4-7

CHANGE IN MOST IMPAIRED DAYS MODELED CONCENTRATIONS OF SULFATE AND NITRATE

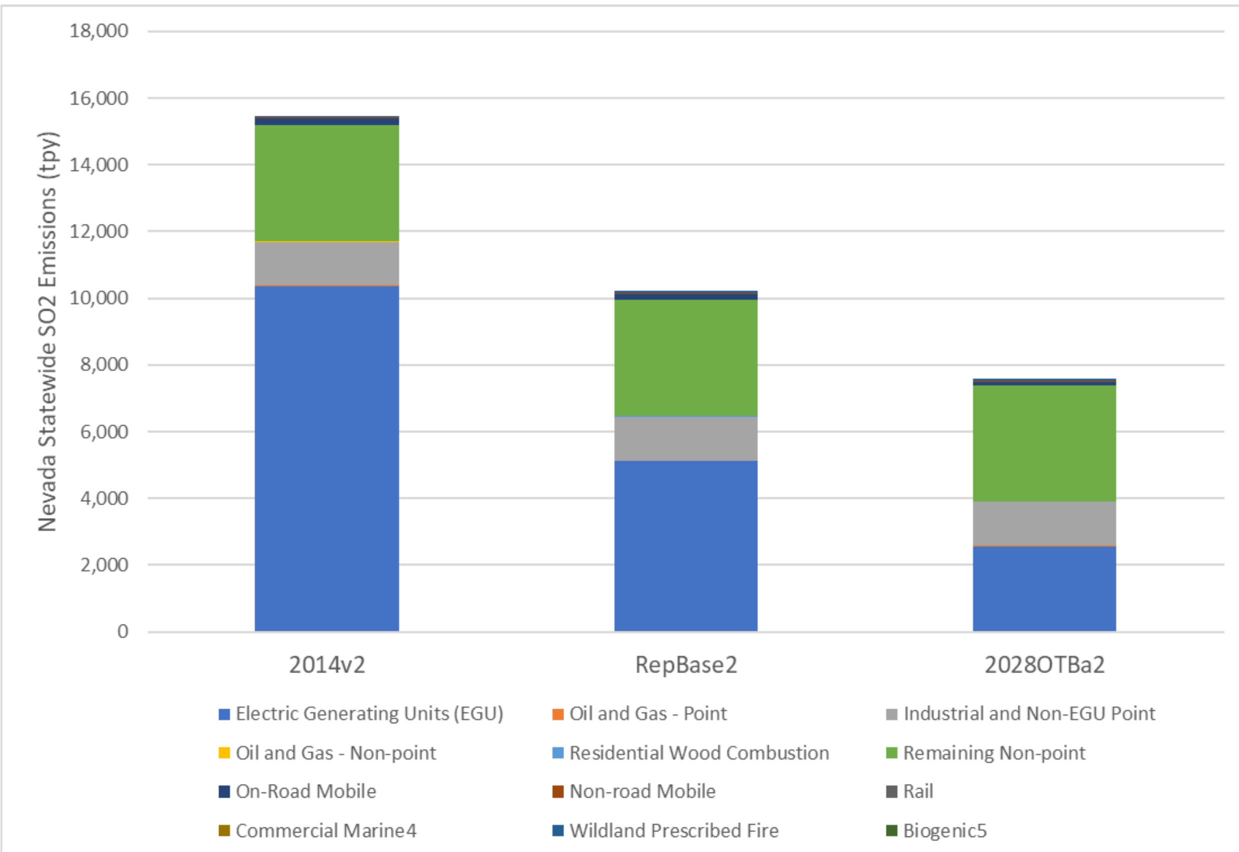
Class I Area	Year	Total SO_4 (Mm^{-1})	US Anthro SO_4 (Mm^{-1})	US Anthro Share SO_4	Total NO_3 (Mm^{-1})	US Anthro NO_3 (Mm^{-1})	US Anthro Share NO_3
Jarbidge Wilderness Area	2028	3.225	0.231	7.16%	0.664	0.188	28.31%

Figure 4-28 summarizes the Nevada SO_2 inventories, while Figure 4-29 summarizes the Nevada NO_x inventories. The projected 2028 emissions inventories for both SO_2 and NO_x show substantial overall reductions from the 2014 baseline inventories. The 2028OTBa2 SO_2 projected inventory shows great reductions from 2014 for EGU point sources. For NO_x emissions, the total projected reductions are very similar, with the largest reduction occurring between RepBase2 and 2028OTBa2.

Comparison of the RepBase2 and 2028OTBa2 emission inventories shows Nevada's total SO_2 emissions decreased by 24 percent from the representative baseline period to 2028, while SO_2 point source emissions decreased by 40 percent. Similarly, Nevada's total NO_x emissions decreased by 46 percent from the representative baseline to 2028, while NO_x point source emissions decreased by 3 percent.

FIGURE 4-28

NEVADA SO_2
EMISSION INVENTORY COMPARISON

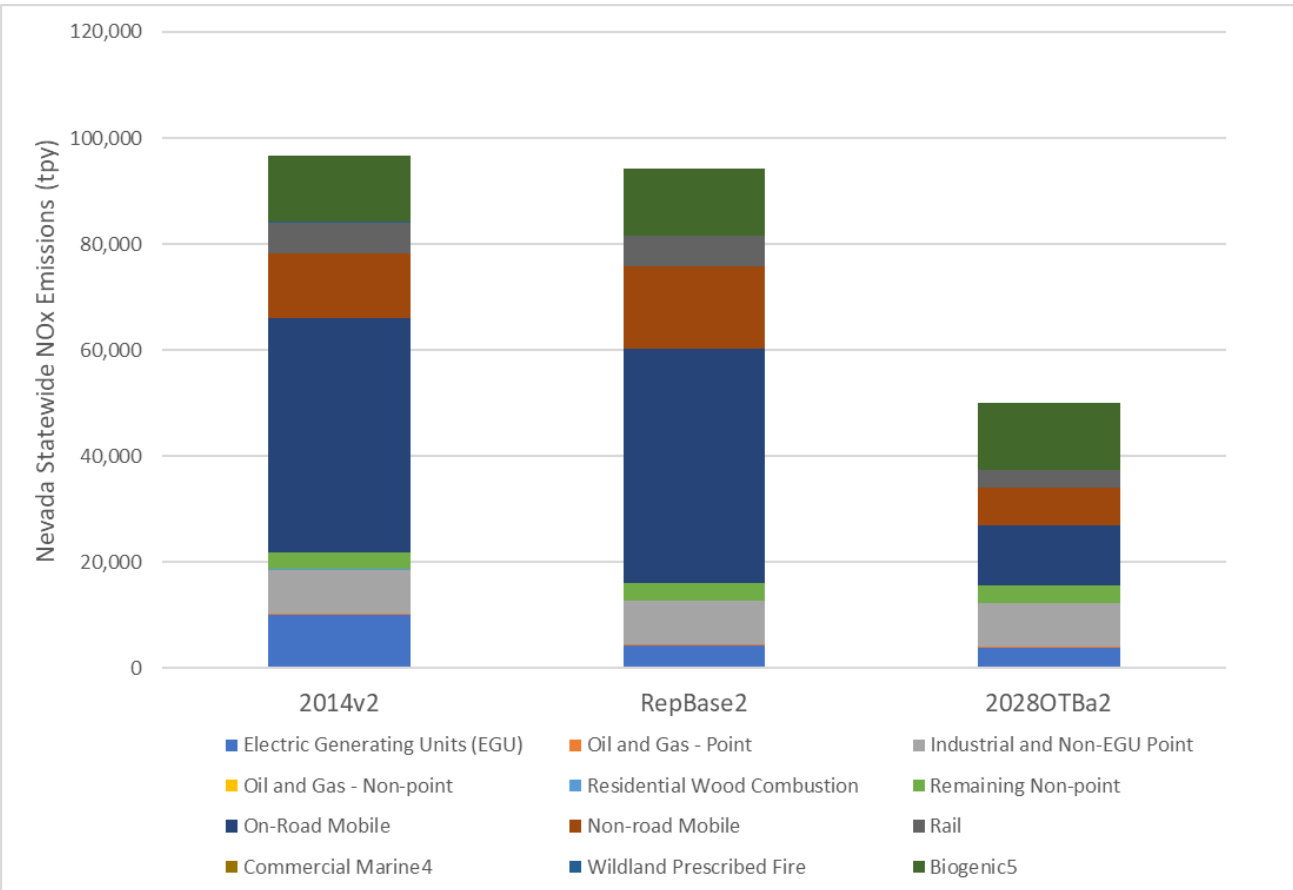


Note that these figures do not reflect all SO_2 and NO_x reductions achieved from point sources for the second implementation period, as the 2028OTBa2 model only serves as baseline 2028 conditions. Additional emission reductions achieved from reasonable progress controls are discussed in Chapter Five and corresponding visibility impacts at Jarbidge WA due to these controls are discussed in Chapter Six. The projected overall particulate sulfate and nitrate concentration reductions at JARB1 are due to Nevada's and regional reductions of SO_2 and NO_x emissions from on-the-books controls.

Regional PSAT and WEP analyses appear to confirm the important contributions of projected sulfate and nitrate emissions from point sources in Idaho and Nevada, as well as the influence of nitrate emissions from mobile sources in the states adjacent to Nevada, to visibility impairment at JARB1 in 2028.

FIGURE 4-29

NEVADA NO_x
EMISSION INVENTORY COMPARISON



4.6 REFERENCES

U.S. EPA 2018. Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. EPA-454/R-18-010. December 2018.

U.S. EPA 2019. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. EPA-457/B-19-003. August 2019.

U.S. EPA 2019. Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling. September 2019.

U.S. EPA 2020. Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. June 2020.

U.S. EPA 2021. Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period. July 2021.

Chapter Five – Four-Factor Control Determinations

5.1 OVERVIEW OF THE FOUR-FACTOR ANALYSIS PROCESS

40 CFR 51.308(f)(2)(i) focuses on the control analyses needed to determine what emission reduction measures will be necessary to make reasonable progress in each state's Long-Term Strategy. States are required to select sources for analysis of control measures, identify emission control measures to be considered for these sources, and evaluate potential controls based on the four statutory factors: costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life.

States are required to evaluate major and minor stationary sources or groups of sources, mobile sources, and area sources. NDEP considered evaluating all groups but determined that more reductions would be achieved from major stationary sources and that any control analyses on minor sources would reasonably determine no controls as cost-effective. Area sources that may be contributing to visibility impairment at Nevada's Class I area were evaluated and it was concluded that most area source emissions were due to fugitive dust, however, no potential controls that could reasonably be implemented and enforced under the agency's local authority were identified. NDEP is depending on current and future federal/state regulations applicable to mobile sources to achieve reductions in that sector.

40 CFR 51.308(f)(2)(iii) requires that states document the technical basis, including cost, engineering, and emissions information, on which the state is relying to determine the emission reduction measures that are necessary to make reasonable progress. This chapter describes the selection of sources to conduct a four-factor analysis, NDEP's coordination with sources and other agencies in developing the four-factor analyses, and the final control determination for each source, including control requirements needed for the Long-Term Strategy.

5.2 SOURCE SCREENING IN NEVADA

NDEP and the air quality agencies of the WRAP used the Q/d method in identifying sources that are reasonably contributing to visibility impairment at any Class I area. Although not as sophisticated as modeling, this surrogate for source visibility impacts is significantly less resource intensive, while still providing a reliable method in determining which in-state sources should conduct a four-factor analysis.

Q/d represents a source's annual emissions in tons (Q) divided by the distance in kilometers (d) between the source and the nearest Class I area. For regional haze purposes, only primary visibility-impairing pollutants were included in a source's total Q: NO_x, SO_2, and PM_{10}. Emissions used to calculate a source's total Q were taken from the 2014v2 NEI. All sources, and their respective total Q, were inventoried and ranked by largest total Q to least. A Q/d threshold of 5 was set, identifying 8 sources that contributed to approximately 77% of statewide total NO_x, SO_2, and PM_{10} emissions. Table 5-1 outlines the sources identified by the Q/d analysis listed in order of potential visibility impacts based on the Q/d value. Aside from the Reid Gardner Station and McCarran International Airport, additional Q/d values are provided in Table 5-1 for the second and third closest Class I areas. These sources provide geographic representation of the three primary industrial areas in the state: the greater Reno area, the Las Vegas area, and the Interstate 80 industrialized corridor. Having sources from a broad geographic cross section of the state provides confidence that the selected stationary sources include those most likely to impair visibility at Class I areas both in Nevada and in neighboring states.

TABLE 5-1

SOURCES IDENTIFIED BY Q/D ANALYSIS TO CONDUCT
A FOUR-FACTOR ANALYSIS

Nearest Class I areas	CIA State	Total Q (tpy)	Distance to CIA (km)	Q/d	Percent of Statewide Q	Running Total of Percent of Statewide Q
Reid Gardner Station Power Plant						
Grand Canyon NP	AZ	6,944	84	**82.56**	19.8%	19.8%
North Valmy Generating Station						
Jarbidge Wilderness Area	NV	12,173	162	**75.10**	34.6%	54.4%
South Warner Wilderness	CA		255	47.74		
Mokelumne Wilderness	CA		330	36.89		
McCarran International Airport						
Grand Canyon NP	AZ	2,770	107	**25.97**	7.9%	62.3%
Lhoist North America Apex Plant						
Grand Canyon NP	AZ	1,662	88	**18.84**	4.7%	67.0%
Zion NP	UT		195	8.52		
Bryce Canyon NP	UT		277	6.00		
Nevada Cement Fernley Plant						
Desolation Wilderness	CA	1,482	102	**14.55**	4.2%	71.2%
Mokelumne Wilderness	CA		136	10.90		
Emigrant Wilderness	CA		180	8.23		
Tracy Generating Station						
Desolation Wilderness	CA	683	82	**8.33**	1.9%	73.1%
Mokelumne Wilderness	CA		122	5.60		
Emigrant Wilderness	CA		167	4.09		
TS Power Plant						
Jarbidge Wilderness Area	NV	834	131	**6.39**	2.4%	75.5%
South Warner Wilderness	CA		309	2.70		
Craters of the Moon NM	ID		362	2.30		
Graymont Pilot Peak Plant						
Jarbidge Wilderness Area	NV	673	131	**5.13**	1.9%	77.4%
Craters of the Moon NM	ID		263	2.56		
Sawtooth Wilderness	ID		297	2.27		

Of the sources listed above, three were considered and later removed from the four-factor analysis requirement. Reid Gardner Station Power Plant was identified using emissions data from the 2014v2 NEI, however, the entire facility ceased operation and was decommissioned in 2017 and has now been completely dismantled.

McCarran International Airport, now named the Harry Reid International Airport, was removed from the four-factor requirement as the vast majority of emissions are due to aircraft takeoffs, landings and ground movement, falling outside of the local air agencies' scope of authority. Table 5-2 lists the facility-wide allowable emissions for NO_x, SO_2, and PM_{10} at McCarran Airport that are listed in the Clark County Department of Environment and Sustainability (CCDES) air quality operating permit. Isolating only the maximum allowable, or controllable, emissions within the permit, a new Q/d of 1.35 is calculated for McCarran Airport, well below NDEP's Q/d threshold of 5.

TABLE 5-2

MCCARRAN AIRPORT CONTROLLABLE EMISSIONS
AND NEW Q/D

Facility	Nearest CIA	Distance to CIA (km)	Facility-Wide Permitted Allowable Emissions (tpy)			New Total Q	New Q/d
			NO_x	SO_2	PM_{10}		
McCarran Int'l Airport	Grand Canyon NP	88	87.95	2.35	28.82	119.12	1.35

5.3 NEVADA FOUR-FACTOR APPROACH

Each source that was identified in the source selection step elected to submit their own four-factor analyses to evaluate existing controls and consider potential additional control measures that may be necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada. NDEP has reviewed, and in some cases revised, the information and data used in the facility's four-factor analyses to ensure the method of evaluating control measures necessary to achieve reasonable progress agrees with the Regional Haze Rule regulatory language, USEPA Final Guidance for the second implementation period of the Regional Haze Rule, USEPA Clarifications Memo, and USEPA Control Cost Manual. In the event that no additional control measures are necessary to make reasonable progress at a source, NDEP evaluated whether existing control measures implemented at the source are necessary to make reasonable progress.

For the majority of the sources, NDEP requested additional information that is supplemental to the initial four-factor analyses submitted by sources, resulting in multiple response letters from the sources to bolster the information and data assumed in the four-factor analysis. NDEP has conducted "Reasonable Progress Control Determinations" that outlines the information assumed in considering control measures necessary for reasonable progress (considering the four statutory factors), and specifies what information was manipulated by NDEP to ensure each source's four-factor analysis meets applicable requirements.

All documentation needed to evaluate the legality and reasonableness of Nevada's reasonable progress conclusions are provided in Appendix B. Each sub-appendix under Appendix B pertains to one source, beginning with NDEP's "Reasonable Progress Control Determination" for the source, followed by the four-factor analysis submitted by the source, and any subsequent response letters. Table 5-3 below outlines Appendix B and where four-factor analysis documents can be located.

TABLE 5-3

LOCATION OF FOUR-FACTOR ANALYSES

Facility	Appendix Location of Four-Factor Analysis Documents
Apex Plant, Lhoist North America	B.1
Pilot Peak Plant, Graymont Western	B.2
TS Power Plant, NNEI	B.3
Fernley Plant, Nevada Cement Company	B.4
Tracy Generating Station, NV Energy	B.5
Valmy Generating Station, NV Energy	B.6

An emissions baseline for each unit evaluated in a four-factor analysis consists of emissions reported in a recent and relevant historical period. An emissions baseline derived from the average emissions of a time frame within 2014 and 2019 was selected by sources to reflect normal operations that is expected to continue through the remainder of the implementation period. If recent emissions varied, years with higher reported emissions were incorporated into the baseline to support a conservative analysis, unless verifiable documentation was provided to confirm that lower emissions will continue and not increase in future years.

Sources required to conduct a four-factor analysis included two EGUs, two lime production plants, and one cement production plant. Typically, these types of facilities, or units, evaluated similar suites of feasible control measures. Although source screening considered emissions reported for NO_x, SO_2, and PM_{10}, most analyses primarily focus on control measures for NO_x and SO_2 emissions, as all sources currently operate PM_{10} controls achieving at least 90% removal efficiency. Table 5-4 outlines the feasible add-on control measures considered. Operational and maintenance improvements were also considered.

TABLE 5-4

ADD-ON NO_x AND SO_2 CONTROLS CONSIDERED IN
FOUR-FACTOR ANALYSES

NO_x Control Measures	SO_2 Control Measures
Selective Non-Catalytic Reduction (SNCR)	Limestone/Lime-Based Flue Gas Desulfurization (FGD)
Selective Catalytic Reduction (SCR)	Dry Sorbent Injection (DSI)
Low NO_x Burners (LNB)	Alternative Low Sulfur Fuels
Dry Low NO_x Combustor	Wet Scrubbing
Over Fired Air (OFA)	Semi-Wet/Dry Scrubbing

All four statutory factors were evaluated and considered in control decisions for reasonable progress. Energy and non-air quality impacts and remaining useful life were considered as separate factors, but typically contributed to adjustments to the cost of compliance. Adverse energy and non-air quality impacts and a short remaining useful life were not used to preclude selection of an otherwise cost-effective control, rather these were considerations that inflated costs. Time necessary for compliance was used to determine a compliance date for controls selected for reasonable progress.

NDEP is relying on a cost-effectiveness ($/ton reduced) threshold of $10,000/ton when considering potential new control measures during the second implementation period. Compared to the BART threshold used during the first implementation period of $5,000/ton, the new threshold for reasonable progress controls is double. This is to ensure that the entire fleet of potential new control measures throughout Nevada are thoroughly considered, as well as, to ensure that enough controls are implemented during the second period to continue achieving reasonable progress at Jarbidge WA and other out-of-state CIAs.

As a result of the four-factor analyses, NDEP has determined the following control measures, listed in Table 5-5, as necessary to make reasonable progress during the second implementation period. Further discussion of the facilities, units, controls, and characterizations of the four statutory factors is provided in the following sections.

TABLE 5-5

CONTROL MEASURES NECESSARY TO MAKE REASONABLE PROGRESS

Facility	Unit	Control	Controlled Pollutant	Existing/New	Compliance Deadline
North Valmy Generating Station	Unit 1	Baghouse and Air Atomized Ignitors	PM_{10}	Existing	Upon SIP approval
		LNB+OFA	NO_x	Existing	Upon SIP approval
		Permanent Closure	-	New	December 31, 2028
	Unit 2	Baghouse and Air Atomized Ignitors	PM_{10}	Existing	Upon SIP approval
		Spray Dryer with Lime Slurry	SO_2	Existing	Upon SIP approval
		LNB+OFA	NO_x	Existing	Upon SIP approval
		Permanent Closure	-	New	December 31, 2028
Tracy Generating Station	Unit 5	Dry Low NO_x Combustor	NO_x	Existing	Upon SIP approval
	Unit 6	Dry Low NO_x Combustor	NO_x	Existing	Upon SIP approval
	Unit 7	Steam Injection	NO_x	Existing	Upon SIP approval
		Permanent Closure	-	New	December 31, 2031
	Unit 32	Dry Low NO_x Combustor and SCR	NO_x	Existing	Upon SIP approval

	Unit 33	Dry Low NO_x Combustor and SCR	NO_x	Existing	Upon SIP approval
Apex Plant	Kiln 1	LNB	NO_x	New	No later than two years after SIP approval
		SNCR	NO_x	New	
	Kiln 3	LNB	NO_x	Existing	
		SNCR	NO_x	New	
	Kiln 4	LNB	NO_x	Existing	
		SNCR	NO_x	New	
Pilot Peak Plant	Kiln 1	LNB	NO_x	Existing	240 days
	Kiln 2	LNB	NO_x	Existing	240 days
	Kiln 3	LNB	NO_x	Existing	240 days

5.4 SUMMARY OF FOUR-FACTOR CONTROL ANALYSES

A full control determination was completed for North Valmy and Tracy Generating Stations, Lhoist Apex and Graymont Pilot Peak lime production plants, and Nevada Cement Fernley cement production plant. A Reasonable Progress Determination was conducted for the TS Power Plant to evaluate potential controls. Emission limitations for reasonable progress were established on a case-by-case basis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, and the remaining useful life of the unit.

The control measures identified by Nevada as necessary to achieve reasonable progress will be installed and operating by a compliance deadline established through the consideration of the "time needed for compliance" statutory factor. Compliance schedules are determined on a case-by-case basis dependent on the type of control, planned outages at the facility, vendor availability, and other factors.

Facilities identified by Nevada's source screening procedure conducted their four-factor analyses internally, while coordinating with NDEP. In some cases, NDEP's review of the submitted four-factor analyses resulted in revisions to the original draft or requests were sent from NDEP to the facility to provide additional information. If the analysis and proposed control technologies were acceptable, NDEP relied on the submitted four-factor analyses to determine which controls are necessary to achieve reasonable progress. Where facility reasonable progress determinations were not accepted, the state made its own determinations using the facility reports as a foundation.

Each four-factor analysis established baseline emissions representative of actual emissions using acid rain data or actual annual emissions reported by each facility. Typically, sources used an annual average baseline comprised of emissions reported to NDEP during the 2016 through 2018 reporting years. All technically feasible controls that were considered for each unit at each facility assume achievable control efficiencies that were confirmed by NDEP. If a control was determined necessary to achieve reasonable progress, the assumed control efficiency was used to derive a new emission limit specific to the controlled pollutant on a case-by-case basis, along with corresponding averaging periods, and monitoring, record keeping, and reporting requirements.

A comparison of the baseline and post-control annual emissions resulting from the outcomes of the four-factor analyses and WRAP emissions inventories are presented for each facility below. The WRAP 2028 On-The-Books (2028OTBa2) emission inventory utilized 2014 NEIv2 emissions, with some adjustments made by states and on-the-books controls set to operate by the end of the period in 2028. Since the 2028OTBa2 modeling output does not include all new controls proposed in this SIP, new RPGs reflecting final reductions achieved through reasonable progress controls are derived in the next chapter.

5.5 NORTH VALMY GENERATING STATION FOUR-FACTOR OVERVIEW

For the purpose of determining whether controls at North Valmy Generating Station are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for North Valmy found in Appendix B.6.a. North Valmy's air quality operating permit is incorporated by reference into this SIP in Appendix A.6.

Note, that NV Energy submitted a four-factor analysis, and subsequent response letters to requests for additional information, for North Valmy and Tracy Generating Stations within the same files. Therefore, NDEP's "Reasonable Progress Control Determination" for North Valmy Generating Station is found in Appendix B.6, but references documents located in Appendix B.5 (sub-appendix for Tracy Generating Station). Table 5-6 outlines the files referenced in making reasonable progress determinations for North Valmy Generating Station, and where they can be found in Appendix B.

TABLE 5-6

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR VALMY

Full Document Title	**Shortened Document Title**	**Date**	**Appendix Location**
North Valmy Generating Station Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Determination*	May 2022	B.6.a
Regional Haze Reasonable Further Progress Four Factor Analysis	*NVE Analysis*	March 13, 2020	B.5.b
RE: Response to Request for Additional Information	*Response Letter 1*	July 8, 2020	B.5.c
RE: Response to a Second Follow-up Request for Additional Information	*Response Letter 2*	January 15, 2021	B.5.d
RE: Response to a Third Follow-up Request for Additional Information	*Response Letter 3*	April 16, 2021	B.5.e
RE: Response to a Fourth Follow-up Request for Additional Information	*Response Letter 4*	May 7, 2021	B.5.f
RE: Response to a Fifth Follow-up Request for Additional Information (Valmy specific)	*Response Letter 5.1*	August 27, 2021	B.5.g
RE: Response to a Fifth Follow-up Request for Additional Information (Tracy specific)	*Response Letter 5.2*	October 11, 2021	B.5.h
RE: Response to a Sixth Follow-up Request for Additional Information	*Response Letter 6*	April 29, 2022	B.5.i
RE: Response to a Seventh Follow-up Request for Additional Information	*Response Letter 7*	May 27, 2022	B.5.j
RE: NV Energy Response to an Eighth Follow-Up Request for Additional Information	*Response Letter 8*	August 5, 2022	B.5.k
Class I Air Quality Operating Permit	Permit		A.6

5.5.1 Baseline Emissions

For the purpose of NV Energy's four-factor analysis for the North Valmy Generating Station, baseline emissions were dervied from the annual average of emissions observed from 2016 through 2018. Table 5-7 shows the baseline emissions assumed for SO_2, NO_x, and PM_{10} emissions at Unit 1 and 2.

TABLE 5-7

VALMY FOUR-FACTOR ANALYSIS BASELINE EMISSIONS

	SO_2	NO_x	PM
Baseline Emission Rates for Unit 1			
2016	1,848 ton/yr	797 ton/yr	22.01 ton/yr
2017	1,232 ton/yr	587 ton/yr	16.27 ton/yr
2018	2,357 ton/yr	1,027 ton/yr	27.76 ton/yr
2016-2018 Annual Average	**1,812 ton/yr** **0.760 lb/MMBtu**	**804 ton/yr** **0.337 lb/MMBtu**	**22.01 ton/yr** **0.0092 lb/MMBtu**
Baseline Emission Rates for Unit 2			
2016	431 ton/yr	839 ton/yr	54.84 ton/yr
2017	356 ton/yr	674 ton/yr	20.97 ton/yr
2018	716 ton/yr	1,493 ton/yr	37.19 ton/yr
2016-2018 Annual Average	**501 ton/yr** **0.158 lb/MMBtu**	**1,002 ton/yr** **0.317 lb/MMBtu**	**37.67 ton/yr** **0.0119 lb/MMBtu**

5.5.2 Identification of Technically Feasible Controls

For Unit 1 at the North Valmy Generating Station, NV Energy identified SCR and SNCR as technically feasible control measures in controlling NO_x emissions, and identified FGD and DSI using Milled Trona as technically feasible control measures in controlling SO_2 emissions. Additional PM_{10} control measures were not evaluated as Unit 1 already implements baghouses and air atomized ignitors to control particulate emissions, representing an existing effective control.

For Unit 2 at the North Valmy Generating Station, NV Energy identified SCR and SNCR as technically feasible control measures in controlling NO_x emissions, and identified upgrades to an existing lime slurry-based spray dryer as a technically feasible control measure in controlling SO_2 emissions. Additional PM_{10} control measures were not evaluated as Unit 2 already implements baghouses and air atomized ignitors to control particulate emissions, representing an existing effective control.

5.5.3 Characterization of Cost of Compliance

All potential new control measures outlined below assume a capital recovery factor of 0.2936, based on a 4-year equipment life (assuming controls go live beginning of 2025 and plant closes at the end of 2028) and an interest rate of 6.75%. A summary of the cost-effectiveness values for each technically feasible control technology considered at North Valmy Generating Station is provided in Table 5-8.

Utilizing the Control Cost Manual spreadsheet in evaluating SNCR as a potential control measure at both Valmy units, a cost-effectiveness value of $16,195/ton and $14,131/ton is estimated for Unit 1 and 2, respectively. Cost calculations assume a retrofit factor of 1. A total annual cost of implementing SNCR on Unit 1 is estimated at $3.2M and is projected to reduce

NO_x emissions by 200 tons per year. For Unit 2, the cost of implementing SNCR is estimated at \$3.5M and is projected to reduce NO_x emissions by 250 tons per year.

Utilizing the Control Cost Manual spreadsheet in evaluating SCR as a potential control measure at both Valmy units, a cost-effectiveness value of \$57,583/ton and \$54,178/ton is estimated for Unit 1 and 2, respectively. Cost calculations assume a retrofit factor of 1.3 due to necessary modifications to the auxiliary power system, space constraints, new ductwork, and new steel and reinforcements. A total annual cost of implementing SCR on Unit 1 is estimated at \$39M and is projected to reduce NO_x emissions by 681 tons per year. For Unit 2, the cost of implementing SCR is estimated at \$45.5M and is projected to reduce NO_x emissions by 841 tons per year.

TABLE 5-8

VALMY FOUR-FACTOR ANALYSIS COST-EFFECTIVENESS SUMMARY

Control	Unit	Baseline Emissions	Tons Reduced	Total Annualized Costs	Cost – Effectiveness
SNCR	1	804 tpy NO_x	200 tpy NO_x	\$3,235,852	\$16,195 /ton
	2	1,002 tpy NO_x	250 tpy NO_x	\$3,527,944	\$14,100 /ton
SCR	1	804 tpy NO_x	681 tpy NO_x	\$39.19 Million	\$57,583 /ton
	2	1,002 tpy NO_x	841 tpy NO_x	\$45.56 Million	\$54,178 /ton
DSI w/ Milled Trona	1	1,812 tpy SO_2	1,338 tpy SO_2	\$15.26 Million	\$11,409 /ton
Limestone-Based FGD	1	1,812 tpy SO_2	1,751 tpy SO_2	\$76.51 Million	\$43,704 /ton
Lime-based FGD	1	1,812 tpy SO_2	1,751 tpy SO_2	\$73.77 Million	\$42,315 /ton
FGD Upgrade	2	2,278 tpy SO_2	365 tpy SO_2	\$17.00 Million	\$46,500 /ton

In evaluating the cost of compliance of replacing the existing DSI system using hydrated lime (designed to control HCl emissions) with a Trona-based Dry Sorbent Injection (Trona DSI) on Valmy Unit 1, the total annual cost of replacing the existing DSI system with a Trona-based DSI system is estimated at \$15.26 million. This system is estimated to reduce annual SO2 emissions by 1,338 tons, or \$11,409 per ton reduced.

The total annual cost of implementing a limestone-based flue gas desulfurization system is \$76.51 million, based on an estimated capital cost of \$247.8M. This system is estimated to reduce annual SO_2 emissions by 1,751 tons, or \$43,704 per ton reduced. The total annual cost of implementing a limestone-based flue gas desulfurization system is \$73.77 million, based on an estimated cost of \$238.2M. This system is estimated to reduce annual SO2 emissions by 1,751 tons, or \$42,135 per ton reduced.

5.5.4 Characterization of Time Necessary for Compliance

For NO_x controls, it is estimated that a minimum of 35 months would be needed to implement SNCR at both Valmy units. A minimum of six years is estimated to be needed to retrofit both Valmy units to implement SCR controls.

For SO_2 controls, it is estimated that a minimum of 34 months would d be needed to implement a DSI system using Milled Trona at Valmy Unit 1. Both FGD systems (limestone-based and lime-based) would require approximately six to eight years. At Valmy Unit 2, upgrading the existing FGD system by replacing the spray nozzles would require a minimum of 46 months before reaching compliance.

5.5.5 Characterization of Energy and Non-Air Quality Environmental Impacts

Both SCR and SNCR have the potential for ammonia slip if too much reagent is emitted unreacted. SCR will increase the parasitic load of the station and cause backpressure in the exhaust flow path.

All potential SO_2 controls would produce solid waste that would trigger EPA's CCR disposal rules. NVE estimates water losses over 61,000 gallons per day via evaporative losses that will occur when the hot boiler flue gas contacts the FGD reagent slurry. Electricity use would also increase in order to operate the system. All of these factors have been accounted for in the cost analysis. DSI systems have the potential to emit a yellow/brownish plume due to excess NO_x. Activated carbon injection is included in the cost analysis to mitigate this.

5.5.6 Characterization of Remaining Useful Life of the Source

As stated above, NVE has committed to shutting down and permanently ceasing operations at both units at North Valmy by December 31, 2028. This is reflected in annualized capital costs for SNCR and SCR.

Although NVE estimates various compliance schedules for each considered control ranging from 34 months up to eight years, NVE has conservatively estimated that all considered controls could be implemented by the end of 2024 when calculating the cost of compliance for both controls. Assuming all controls go on-line at the beginning of 2025 and both units permanently close at the end of 2028, a remaining useful life of 4 years is estimated.

5.5.7 Decisions on what Control Measures are Necessary to Make Reasonable Progress

Based on the four statutory factors, NDEP concludes that no new control measures evaluated for the North Valmy Generating Station are necessary to make reasonable progress.

NDEP is relying on a federally enforceable and permanent closure date of December 31, 2028 for both units (used to reduce the remaining useful life of each unit and inflate cost-effectiveness values for all new control measures considered in the four-factor analysis) as necessary to achieve reasonable progress. During the time both units are in operation prior to closure, NDEP is also relying on the continued use of existing controls at Unit 1 (baghouse to control PM_{10} emissions and Low NO_x burners and over fired air to control NO_x emissions) and Unit 2 (baghouse to control PM_{10} emissions, Low NO_x burners and over fired air to control NO_x emissions, and spray dryer using a lime slurry to control SO_2 emissions) to make reasonable progress.

NDEP is submitting the following controls, emission limits, and associated requirements, for approval into the SIP as measures necessary to make reasonable progress during second implementation period of Nevada's Regional Haze SIP (Table 5-9). These emission limits and associated requirements, listed in the source's air quality operating permit, are incorporated into the SIP by reference. The North Valmy Generating Station's permit, Permit No. AP4911-0457.03, can be found in Appendix A.6 of Nevada's second Regional Haze SIP.

TABLE 5-9

NORTH VALMY PERMIT CONDITIONS INCORPORATED BY REFERENCE

North Valmy Generating Station, Permit No. AP4911-0457.03		
	Citation	Permit Condition
Unit 1 (System 01 – Unit #1 Boiler)		
NO_x	VI.A.1.a.(3)	Multi-stage combustion to control nitrogen oxides emissions through the use of Low NO_x Burners and Over Fired Air.
	VI.A.2.e	The discharge of NOx (nitrogen oxides) to the atmosphere will not exceed **0.70** pound per million Btu, based on a 3-hour rolling average.
PM_{10}	VI.A.1.a.(1)-(2)	(1) Baghouse to control particulate matter emissions. (2) Air atomized ignitors to control particulate matter and opacity during startup and for flame stabilization
	VI.A.2.b	The discharge of PM (total particulate matter) to the atmosphere will not exceed **0.10** pound per million Btu.
	VI.A.4.a.1-3 VI.A.4.a.14	Compliance/Performance Testing
	VI.A.4.b.3 VI.A.4.b.7 VI.A.4.b.10	Monitoring
	VI.A.4.d.4-5 VI.A.4.d.7	Recordkeeping
	VI.A.4.e	Reporting
Unit 2 (System 02 – Unit #2 Boiler)		
NO_x	VI.B.1.a.(4)	Multi-stage combustion to control nitrogen oxides emissions through the use of Low NO_x Burners and Over Fired Air.
	VI.B.2.e	(1) 210 ng/J (**0.50 lb/million Btu**) heat input derived from combustion of Sub-bituminous coal; (2) 260 ng/J (**0.60 lb/million Btu**) heat input derived from the combustion of Bituminous coal;

		(3) 65 percent reduction of potential combustion concentration when combusting solid fuel
SO_2	VI.B.1.a.(2)	Spray dryer using a lime slurry with a rated **70%** minimum sulfur dioxide removal efficiency.
	VI.B.2.i	(1) 520 ng/J (**1.20 lb/million Btu**) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or (2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (**0.60 lb/million Btu**) heat input.
PM_{10}	VI.B.1.a.(1) VI.B.1.a.(3)	(1) Baghouse to control particulate matter emissions. (3) Air atomized ignitors to control particulates and opacity during startup and for flame stabilization
	VI.B.2.b	(1) 13 ng/J (**0.03 lb/million Btu**) heat input derived from the combustion of solid, liquid, or gaseous fuel; (2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; (3) and 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.
	VI.B.4.a.1-3 VI.B.4.a.14	Compliance/Performance Testing
	VI.B.4.b.3-4 VI.B.4.b.7 VI.B.4.b.9-10	Monitoring
	VI.B.4.d.4-7	Recordkeeping
	VI.B.4.e	Reporting
All Units Monitoring, Recordkeeping, and Reporting Requirements		
Section V.A - V.G		General Monitoring, Recordkeeping, and Reporting Requirements
Closure Date		
Section XI.C		As part of Nevada's Regional Haze State Implementation Plan's (SIP) Long-Term Strategy to achieve reasonable progress, the Permittee shall shutdown and permanently cease operation of **System 01 (S2.001)** and **System 02 (S2.002)** no later than December 31, 2028.

5.5.8 Discussion of North Valmy Generating Station Four-Factor Outcome

NV Energy has committed to cease operations and shutdown both electrical generating units at North Valmy Generating Station by December 31, 2028. With this closure date, no additional controls on either unit are cost-effective or necessary to achieve reasonable progress.

NV Energy's four-factor analysis relies on an emissions baseline derived from the annual average of emissions reported in 2016 through 2018. The emission reductions resulting from closure of both units are shown below in Table 5-10. By the end of 2028, or the end of the second implementation period, 1,746 tons per year of NO_x reductions, 2,313 tons per year SO_2 reductions, and 60 tons per year of PM_{10} reductions are expected from the closure of both Valmy units, amounting to a total of 4,119 tons per year reductions of visibility impairing pollutants.

WRAP emissions inventories underestimated the final reductions expected to be achieved at North Valmy Generating Station. Emissions reported by the Valmy Generating Station in 2016 were used to forecast Valmy's emissions in the 2028OTBa2 modeling emission inventory, or 2028 baseline before the implementation of potential controls. Beyond the 2028OTBa2 model, Valmy will reduce NO_x emissions by an additional 1,583 tpy and SO_2 emissions by an additional

2,281 tpy by the end of the second implementation period. New reasonable progress goals for 2028 are derived in Chapter 6 to account for these additional reductions.

TABLE 5-10

VALMY MODELING VS. FINAL EMISSION REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		**Baseline Emissions**	**Emissions after Controls**	**Emission Reductions**
Unit 1					
NOx	785		796	0	796
SO2	1,850		1,812	0	1812
PM10	22		22	0	22
Unit 2					
NOx	798		950	0	950
SO2	431		501	0	501
PM10	55		38	0	38
Total NOx	1,583		1746	0	1746
Total SO2	2,281		2313	0	2313
Total PM10	77		60	0	60

Note: Negative values reflect annual emissions increases.

5.6 TRACY GENERATING STATION FOUR-FACTOR OVERVIEW

For the purpose of determining whether controls at the Tracy Generating Station are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for Tracy found in Appendix B.5.a. Tracy's air quality operating permit is incorporated by reference into this SIP in Appendix A.5. Table 5-11 outlines the files referenced in making reasonable progress determinations for the Tracy Generating Station, and where they can be found in Appendix B.

TABLE 5-11

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR TRACY

Full Document Title	**Shortened Document Title (used in this document)**	**Date**	**Appendix Location**
Tracy Generating Station Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Determination*	May 2022	B.5.a
Regional Haze Reasonable Further Progress Four Factor Analysis	*NVE Analysis*	March 13, 2020	B.5.b
RE: Response to Request for Additional Information	*Response Letter 1*	July 8, 2020	B.5.c
RE: Response to a Second Follow-up Request for Additional Information	*Response Letter 2*	January 15, 2021	B.5.d
RE: Response to a Third Follow-up Request for Additional Information	*Response Letter 3*	April 16, 2021	B.5.e
RE: Response to a Fourth Follow-up Request for Additional Information	*Response Letter 4*	May 7, 2021	B.5.f
RE: Response to a Fifth Follow-up Request for Additional Information (Valmy specific)	*Response Letter 5.1*	August 27, 2021	B.5.g
RE: Response to a Fifth Follow-up Request for Additional Information (Tracy specific)	*Response Letter 5.2*	October 11, 2021	B.5.h
RE: Response to a Sixth Follow-up Request for Additional Information	*Response Letter 6*	April 29, 2022	B.5.i
RE: Response to a Seventh Follow-up Request for Additional Information	*Response Letter 7*	May 27, 2022	B.5.j
RE: NV Energy Response to an Eighth Follow-Up Request for Additional Information	*Response Letter 8*	August 5, 2022	B.5.k
Class I Air Quality Operating Permit	Permit		A.5

All major emission units currently in operation at the Tracy Generating Station that were considered in the facility's four-factor analysis are summarized in Table 5-12.

TABLE 5-12

LIST OF UNITS AT TRACY

NDEP Unit ID	NVE Unit ID	Description (and Nominal Rating)
Unit 3	Unit 3	Steam Boiler (MG) 113 MW
Unit 5	Clark Mountain 3	GE EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)
Unit 6	Clark Mountain 4	GE 7EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)
Unit 7	Piñon Pine 4	GE 6FA NG Combined Cycle Combustion Turbine 107 MW (+23 MW Duct Burners)
Unit 32	Unit 8	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners
Unit 33	Unit 9	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners

Not all units at the Tracy Generating Station were required to be considered for potential new control measures. This was due to either low utilization, low emissions, or existing effective controls. Units 5 and 6 were screened out from further consideration of potential new control measures based on low utilization and low emissions. Units 32 and 33 were screened out from further consideration of potential new control measures based on existing effective controls and low emissions. Baseline emissions for Units 5, 6, 32, and 33 are provided in the following section.

Units 5 and 6 currently use Dry Low NO_x combustors to control NO_x emissions, and units 32 and 33 currently use Dry Low NO_x combustors and SCR to control NO_x emissions. NDEP considers the continued use of these existing controls as necessary to achieve reasonable progress.

Units 3 and 7 were evaluated for potential new control measures for NO_x emissions considering the four statutory factors. Potential new control measures for SO_2 and PM_{10} were not considered for any units at the Tracy Generating Station, as all units burn natural gas, resulting in low annual emissions for SO_2 and PM_{10}.

To comply with BART during the first round of Regional Haze in Nevada, Unit 3 discontinued the occasional use of distillate fuel and was retrofitted with the best available Low-NO_x Burners. NDEP does not consider these control measures to reduce NO_x, SO_2, and PM_{10} emissions as necessary to achieve reasonable progress as they are already incorporated into Nevada's Regional Haze SIP to satisfy BART.

Currently, the Unit 7 turbine uses steam injection to partially quench the heat of combustion to control NO_x emissions to approximately 41 ppm at 15% O_2 (2016-2018 average). NDEP considers the continued use of this control measure to control NO_x emissions as necessary to achieve reasonable progress.

5.6.1 Baseline Emissions

In NV Energy's initial four-factor analysis (*NVE Analysis* found in Appendix B.5.b) baseline emissions were derived from the annual average of emissions from 2016 through 2018. NDEP is relying on the 2016 through 2018 baseline emissions in evaluating Units 5, 6, 32, and 33, as annual emissions in 2018 were the most recent emissions data available at the time these units were screened out from a four-factor requirement. Table 5-13 outlines the baseline emission for units 5, 6, 32, and 33.

TABLE 5-13

TRACY FOUR-FACTOR ANALYSIS BASELINE EMISSIONS FOR UNITS 5, 6, 32, AND 33

Unit ID	**Average NO_x Emissions (tpy)**	**Average SO_2 Emissions (tpy)**	**Average PM_{10} Emissions (tpy)**
Unit 5	12.0	0.3	1.0
Unit 6	10.6	0.2	0.8
Unit 32	38.5	4.0	24.3
Unit 33	37.5	4.0	23.8

For the purpose of NV Energy's four-factor analysis for the Tracy Generating Station, baseline emissions were adjusted to reflect the annual average of emissions observed from 2016 through 2020. Emissions data for 2019 and 2020 were incorporated into the baseline emissions for Units 3 and 7 as they became available and were included in later Response Letters submitted by NV Energy. Tables 5-14 and 5-15 show the baseline emissions assumed for SO_2, NO_x, and PM_{10} emissions at Units 3 and 7.

TABLE 5-14

TRACY FOUR-FACTOR ANALYSIS BASELINE EMISSIONS FOR UNIT 3

	Unit 3 Emissions (tpy)				
Year	**2016**	**2017**	**2018**	**2019**	**2020**
Total Annual NO_x	77	61	114	230	210
2016-2018 Average	84				
2016-2020 Average	138				

TABLE 5-15

TRACY FOUR-FACTOR ANALYSIS BASELINE EMISSIONS FOR UNIT 7

	Unit 7 Emissions (tpy)				
Year	**2016**	**2017**	**2018**	**2019**	**2020**
Total Annual NO_x	190	182	269	315	293
2016-2018 Average	213				
2016-2020 Average	250				

5.6.2 Identification of Technically Feasible Controls

As described in NDEP's Reasonable Progress Determination for the Tracy Generating Station (*NDEP Tracy Determination)*, Units 5, 6, 32, and 33 were screened out from further consideration of additional control measures, since these units all have existing effective controls and low annual emissions, indicating that a four-factor analysis would not result in any cost-effective additional controls that would be necessary to achieve reasonable progress for the second implementation period.

For Unit 3 at the Tracy Generating Station, NV Energy identified SCR and SCNR as technically feasible control measures in controlling NO_x emissions.

For Unit 7 at the Tracy Generating Station, NV Energy identified SCR and Dry Low NO_x Combustors as technically feasible control measures in controlling NO_x emissions.

Since all units at the Tracy Generating Station are natural gas fired, potential additional SO_2 and PM_{10} control measures were not evaluated as the use of natural gas is considered as an existing effective control in controlling SO_2 and PM_{10} emissions. As seen in the above table for baseline emissions, SO_2 and PM_{10} emissions at all units are low, and would likely not result in a cost-effective add-on control for SO_2 and PM_{10} emissions that would be necessary to achieve reasonable progress if a four-factor analysis were conducted.

5.6.3 Characterization of Cost of Compliance

As shown in Table 5-16, all potential control measures evaluated for Units 3 and 7 yield a cost-effectiveness value above NDEP's threshold of $10,000 per ton of NO_x reduced. Cost information used to determine the total annualized costs of each control that NDEP is relying on can be found in the *NDEP Tracy Determination* and other supporting documentation found in Appendix B.5.

TABLE 5-16

TRACY FOUR-FACTOR ANALYSIS COST-EFFECTIVENESS SUMMARY

Control	Unit	Baseline Emissions	Tons Reduced	Total Annualized Costs	Cost – Effectiveness
Dry Low NO_x Combustor	7	250 tpy NO_x	157 tpy NO_x	$2,724,697	$17,355 /ton
SNCR	3	138 tpy NO_x	35 tpy NO_x	$474,641	$13,561 /ton
SCR	7	250 tpy NO_x	225 tpy NO_x	$2,259,408	$10,064 /ton
	3	138 tpy NO_x	124 tpy NO_x	$1,387,040	$11,186 /ton

5.6.4 Characterization of Time Necessary for Compliance

For controls considered for Unit 3, an estimated two to three years would be needed to fully implement SCR or SNCR. For Unit 7, 47 months would be needed to fully implement SCR and two years for implementation of Dry Low NO_x combustors. These timeframes include design, permitting, procurement, installation, startup, and schedules that support regional electrical needs during each unit's outage.

5.6.5 Characterization of Energy and Non-Air Quality Environmental Impacts

Both SNCR and SCR have the potential to produce "ammonia slip." Installation of SCR in the exhaust flow path of the boiler causes a backpressure which must be offset by increased electrical demand. This increased energy use is reflected in the economic analysis as one of the operating costs for SCR. An annual electricity cost of $48,551 in 2019 dollars is estimated in Appendix B of the "Tracy Generating Station Four Factor Analysis" within the *NVE Analysis*.

For the installation of a Dry Low NO_x Combustor, NVE states in the *NVE Analysis* that this control would have a negative impact on the plant's water balance and result in a wastewater stream that would require treatment or disposal. A DLN conversion would also decrease the electrical generation of the turbine because of the decreased mass flow. This would add an annual cost of $870,000 in energy purchases.

5.6.6 Characterization of Remaining Useful Life of the Source

There is currently no federally enforceable closure date of Unit 3 that would restrict the remaining useful life of the unit when considering annualized capital costs. Because of this, NDEP is relying on the recommended life of SNCR and SCR listed in the EPA Control Cost Manual of 20 years and 30 years, respectively.

NDEP is relying on a service life of at most only 6 years before permanent shutdown of the unit for SCR implementation. NDEP is relying on a 9-year life for a Dry Low NO_x Combustor on Unit 7 given that the control go online by the end of 2022 and the unit permanently ceases operation at the end of 2031.

5.6.7 Decisions on what Control Measures are Necessary to Make Reasonable Progress

Based on the four statutory factors, NDEP concludes that no new control measures evaluated for the Tracy Generating Station are necessary to make reasonable progress.

NDEP is relying on a federally enforceable and permanent closure date of December 31, 2031 for Unit 7 (used to reduce the remaining useful life of the unit and inflate cost-effectiveness values for all new control measures considered for Unit 7 in the four-factor analysis) as necessary to achieve reasonable progress. During the time Unit 7 remains in operation prior to closure, NDEP is also relying on the continued use of existing controls (steam injection to control NO_x emissions) to make reasonable progress.

As stated above, NDEP is relying on the continued use of existing NO_x controls at Units 3, 5, 6, 32, and 33 to make reasonable progress.

NDEP is submitting the following controls, emission limits, and associated requirements, for approval into the SIP as measures necessary to make reasonable progress during second implementation period of Nevada's Regional Haze SIP (Table 5-17). These emission limits and associated requirements, listed in the source's air quality operating permit, are incorporated into the SIP by reference. The Tracy Generating Station's permit, Permit No. AP4911-0194.04, can be found in Appendix A.5 of Nevada's second Regional Haze SIP.

TABLE 5-17

TRACY PERMIT CONDITIONS INCORPORATED BY REFERENCE

Tracy Generating Station, Permit No. AP4911-0194.04		
	Citation	Permit Condition
Unit 5 (System 05A – Clark Mountain Combustion Turbine #3)		
NO_x	IV.B.1.a	Emissions from **S2.006** shall be controlled by **Dry Low NO_X Burners** while combusting natural gas only. Emissions from **S2.006** shall be controlled with **Water Injection** while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defined in **B.2.c.** of this section. Note, these are not add-on controls.
	IV.B.3.f	The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed: (1) **9** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling period; (2) **42.0 pounds** per hour, based on a 720-hour rolling period; (3) **122.64** tons per year, based on a 12-month rolling period.
Unit 6 (System 06A – Clark Mountain Combustion Turbine #4)		
NO_x	IV.D.1.a	Emissions from **S2.007** shall be controlled by **Dry Low NO_X Burners** while combusting Pipeline Natural Gas only. Emissions from **S2.006** shall be controlled with **Water Injection** while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defied in **D.2.c.** of this section. Note, these are not add-on controls.
	IV.D.3.f	The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed: (1) **9** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling period; (2) **42.0 pounds** per hour, based on a 720-hour rolling period; (3) **122.64** tons per year, based on a 12-month rolling period.
Unit 7 (System 07C – Tracy Unit #4 Piñon Pine Combustion Turbine)		
NO_x	IV.F.1	a. Emissions from **S2.009** shall be controlled by a **Steam Injection** for control of NO_X. b. Emissions from **S2.009.1** shall be controlled by **Dry Low NO_X Burners**. Note, these are not add-on controls.
	IV.F.3.f	The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed **141.0 pounds** per hour, nor more than **533.1 tons** per 12-month rolling period.
Unit 32 (System 32 – Combined Cycle Combustion Turbine Circuit No. 8)		
NO_x	IV.L.1.a	NO_X emissions from **S2.064 and S2.065** shall be controlled by a **Selective Catalytic Reduction (SCR)**. The SCR shall utilize Ammonia Injection into the SCR at a volume specified by the manufacturer.
	IV.L.3.g	The discharge of **NO_X** to the atmosphere shall not exceed **2.0** parts per million by volume (ppmv) at 15 percent oxygen on a dry basis, based on a 3-hour rolling period.
Unit 33 (System 33 – Combined Cycle Combustion Turbine Circuit No. 9)		
NO_x	IV.M.1.a	NO_X emissions from **S2.066 and S2.067** shall be controlled by a **Selective Catalytic Reduction (SCR)**. The SCR shall utilize Ammonia Injection into the SCR at a

		volume specified by the manufacturer.
	IV.M.3.g	The discharge of **NO_X** to the atmosphere shall not exceed **2.00** parts per million (ppmv) by volume at 15 percent oxygen and on a dry basis, per 3-hour rolling period.
All Units – Monitoring, Recordkeeping, Reporting		
	V.A & V.C	Oxides of Nitrogen (NO_x) Continuous Emissions Monitoring System (CEMS) Conditions
Closure Date		
VIII.A.		As part of Nevada's Regional Haze State Implementation Plan's (SIP) Long-Term Strategy to achieve reasonable progress, the Permittee shall shutdown and permanently cease operation of **System 07C (S2.009, S2.009.1)** no later than December 31, 2031.

5.6.8 Discussion of Tracy Generating Station Four-Factor Outcome

Upon conclusion of the initial four-factor analysis and after discussions with NDEP, NV Energy has since committed to NDEP to cease operations at Unit 7 Piñon Pine by December 31, 2031. This new closure date lowered the remaining useful life of the unit from 30 years to approximately 6 years, inflating the cost effectiveness value to $10,064/ton for SCR and $17,355/ton for Dry Low NO_x combustors. NDEP does not consider controls above $10,000/ton as cost-effective for the second implementation period of the Regional Haze Rule. Reductions from the closure of this unit will not be observed during the second implementation period, ending in 2028, but will be observed in Nevada's third implementation period of the Regional Haze Rule. Because of this, expected reductions cannot be quantified or assumed in Nevada's reasonable progress goals for the second implementation period.

In the 2028OTBa2 emission inventory, facility emissions for Tracy are taken from annual emissions reported in 2018. By the end of the second implementation period in 2028, final reductions achieved from the unit's closure will not be observed yet. To reflect this, NDEP expects no emission reductions at the Tracy Generating Station as a result of this round's four-factor analyses by the end of the planning period. An emissions summary is outlined in Table 5-15.

Although there is a slight difference in NO_x emissions between 2028OTBa2 and the Emissions After Controls inventories, as shown in Table 5-18, this is a result of different baseline emissions used and not because of reductions achieved from add-on controls considered in the four-factor analysis. Because of this, there will be no adjustments made to the reasonable progress goals provided by the WRAP to reflect additional reductions at Tracy.

TABLE 5-18

TRACY MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		**Baseline Emissions**	**Emissions after Controls**	**Emission Reductions**
Unit 3 Steam Boiler					
NOx	114		84	84	0
SO2	1		1	1	0
PM10	2		2	2	0
Unit 4 Clark Mountain 3					
NOx	22		12	12	0
SO2	1		1	1	0
PM10	1		1	1	0
Unit 5 Clark Mountain 4					
NOx	20		11	11	0
SO2	1		1	1	0
PM10	1		1	1	0
Unit 6 Pinon Pine 4					
NOx	267		250	250	0
SO2	1		1	1	0
PM10	7		7	7	0
Unit 8					
NOx	40		39	39	0
SO2	4		4	4	0
PM10	24		24	24	0
Unit 9					
NOx	40		38	38	0
SO2	4		4	4	0
PM10	24		24	24	0
Total NOx	503		434	434	0
Total SO2	12		12	12	0
Total PM10	59		59	59	0

Aside from the closure of the Piñon Pine unit by December 31, 2031, Nevada is also relying on existing controls, listed in Table 5-19, that effectively control visibility impairing pollutants. The continued use of these existing controls will be included in Nevada's Long Term Strategy for the second implementation period, along with the current corresponding NO_x emission limits for each unit listed in the facility's current operating permit. These listed controls target NO_x emissions as the Tracy facility primarily burns pipeline natural gas.

TABLE 5-19

TRACY EXISTING CONTROLS FOR NO_x

Permit ID	NVE ID	Description and Nominal Rating	Current Control	Permitted NO_x Emission Limit
System 3	3	Steam Boiler (NG) 113 MW	Low-NO_x Burner	0.19 lb/MMBtu based on a 12-month rolling average
System 5	Clark Mountain 3	GE EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)	Dry Low NO_x combustors w/ NG (water injection if distillate)	9 ppmv based on a 24-hour rolling average
				42 lb/hr based on a 720-hour rolling average
				122.64 tpy based on a 12-month rolling average
System 6	Clark Mountain 4	GE 7EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)	Dry Low NO_x combustors w/ NG (water injection if distillate)	9 ppmv based on a 24-hour rolling average
				42 lb/hr based on a 720-hour rolling average
				122.64 tpy based on a 12-month rolling average
System 7	Piñon Pine 4	GE 6FA NG Combined Cycle Combustion Turbine 107 MW (+23 MW Duct Burners)	steam injection	141.0 lb/hr, nor more than 533.10 tpy based on a 12 month rolling average
System 32	Unit 8	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners	Low NO_x combustors, SCR, & Ox. catalyst	87.6 tons per year
				2 ppmv based on a 3-hour average
System 33	Unit 9	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners	Low NO_x combustors, SCR, & Ox. catalyst	87.6 tons per year
				2 ppmv based on a 3-hour average

5.7 APEX PLANT FOUR-FACTOR OVERVIEW

For the purpose of determining whether controls at the Apex Plant are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for the Apex Plant found in Appendix B.1.a. The Apex Plant's air quality operating permit is incorporated by reference into this SIP in Appendix A.1. Table 5-20 outlines the files referenced in making reasonable progress determinations for the Apex Plant, and where they can be found in Appendix B.

TABLE 5-20

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR APEX PLANT

Full Document Title	**Shortened Document Title (used in this document)**	**Date**	**Appendix Location**
Apex Plant Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Determination*	March 2022	B.1.a
Regional Haze Second Planning Period Four-Factor Analysis	*LNA Analysis*	March 24, 2021	B.1.b
RE: RHR Apex Plant Update	*LNA Email*	September 13, 2021	B.1.c
RE: Lhoist North America of Arizona, Inc. - Apex Plant Comments on Draft 2021 Regional Haze Four Factor Review and Initial Control Determination	*LNA Comments*	October 13, 2021	B.1.d
Class I Air Quality Operating Permit	Permit		A.1

5.7.1 Baseline Emissions

The Apex Plant is a lime production facility that operates four horizontal rotary preheater lime kilns. Baseline emissions assumed for each kiln for the purpose of conducting a four-factor analysis are provided in Table 5-21. The baseline emissions are derived from the annual average of emissions reported from 2016 to 2018.

TABLE 5-21

APEX PLANT FOUR-FACTOR ANALYSIS BASELINE EMISSIONS

Process Level	**SO_2 Emissions (tpy)**	**NO_x Emissions (tpy)**	**PM_{10} Emissions (tpy)**
Kiln 1	107.30	304	18.46
Kiln 2	5.32	19	1.12
Kiln 3	14.42	154	15.81
Kiln 4	8.21	687	23.04
Facility-Wide (Total)	135	1,164	58.43

5.7.2 Identification of Technically Feasible Control Measures

For all kilns at the Apex Plant, Lhoist North America identified LNB and SNCR as technically feasible control measures in controlling NO_x emissions. LNB is only considered for Kilns 1 and 2, as Kilns 3 and 4 already implement the control. SNCR is evaluated for all four kilns.

For Kilns 2 and 4 at the Apex Plant, Lhoist North America identified a fuel switch to use of natural gas only as a technically feasible control measure in controlling SO2 emissions. This was not considered for Kilns 1 and 3 since these kilns are intended to produce dolomitic lime, which cannot be produced using 100% natural gas. Kilns 2 and 4 are intended to produce HiCal lime, which can be produced using 100% natural gas.

Additional PM_{10} controls are not evaluated for the Apex Plant kilns, as PM_{10} emissions at all four kilns are already controlled by baghouses that meet the definition of best available control technology (BACT). Low annual baseline PM_{10} emissions confirm that all four kilns are effectively controlled by the existing baghouses.

5.7.3 Characterization of Cost of Compliance

Table 5-22 summarizes how the cost of compliance was characterized for each control measure considered in the facility's four-factor analysis using baseline emissions, assumed control efficiencies, total tons reduced, total annualized costs, and cost-effectiveness values (annual dollars per ton of pollutant reduced).

Cost-effectiveness values for the implementation of LNB and SNCR are focused on achievable NO_x reductions based on the baseline NO_x emissions and assumed control efficiency of each control. A 10% NO_x reduction is assumed for the implementation of LNBs. A 20% NO_x reduction at Kilns 1, 2, and 3, and a 50% NO_x reduction at Kiln 4, are assumed for the implementation of SNCR. The control efficiency of SNCR differs between Kiln 4 and the rest of the Apex Plant kilns due to differences in age and configuration (discussed further in Lhoist's four-factor analysis).

Although switching to 100% natural gas at Kilns 2 and 4 have the potential to reduce SO_2 and PM_{10} emissions, increased use of natural gas increases NO_x emissions. To ensure the change in all visibility impairing pollutants are considered, baseline emissions and tons reduced are calculated from the sum of NO_x, SO_2, and PM_{10} emissions. The assumed control efficiency is only applied to SO_2 emissions. For Kiln 4's case, the increase in NO_x emissions surpasses the reduced SO_2 and PM_{10} emissions, resulting in an overall increase in emissions (negative tons reduced value) that produces a negative cost-effectiveness value (marked N/A in table).

TABLE 5-22

APEX PLANT FOUR-FACTOR ANALYSIS COST-EFFECTIVENESS SUMMARY

Control	Kiln	Baseline Emissions (tpy)	Assumed Control Efficiency	Tons Reduced (tpy)	Total Annualized Costs	Cost – Effectiveness
LNB	1	304 tpy NO_x	10%	30.35 tpy NO_x	$25,792	$850 /ton
	2	19 tpy NO_x	10%	1.91 tpy NO_x	$25,792	$13,494 /ton
SNCR	1	304 tpy NO_x	20%	60.70 tpy NO_x	$164,394	$2,708 /ton
	2	19 tpy NO_x	20%	3.82 tpy NO_x	$144,681	$37,847 /ton
	3	154 tpy NO_x	20%	30.84 tpy NO_x	$154,044	$4,995 /ton
	4	687 tpy NO_x	50%	343.34 tpy NO_x	$262,344	$764 /ton
Fuel Switch to 100% NG	2	23.66 tpy NO_x, SO_2, and PM_{10}	99.92%	1.02 tpy NO_x, SO_2, and PM_{10}	$8,708,565	$8,666,204 /ton
	4	724.46 tpy NO_x, SO_2, and PM_{10}	99.62%	-147.92 tpy NO_x, SO_2, and PM_{10}.	$1,589,821	N/A

5.7.4 Characterization of Time Necessary for Compliance

Lhoist North America indicates that the time necessary for compliance of LNB and SNCR across all kilns would require two years, while a fuel-switch to 100% natural gas could be implemented at Kilns 2 and 4 by 2028, or approximately six years.

5.7.5 Characterization of Energy and Non-Air Quality Environmental Impacts

An expected decrease in efficiency throughout the facility as significant energy and water use is increased to support the SNCR technology is represented as additional power costs in the evaluation of cost of compliance. An additional annual power cost of $16,272 per kiln is estimated based on LNA’s previous experience in implementing SNCR on Lhoist’s Nelson facility. It is also acknowledged that the use of SNCR, and urea as a reagent, may introduce ammonia slip to the kilns. This is not accounted for in the cost calculations.

No energy and non-air quality impacts were identified when considering the implementation of Low-NO_x Burners or a fuel switch to 100% natural gas.

5.7.6 Characterization of Remaining Useful Life of the Source

Currently, there is no federally enforceable closure date for the Apex Plant. Because of this, the typical life of LNB and SNCR specified in the USEPA Control Cost Manual of 20 years is assumed. A 20-year life is also assumed for switching to 100% natural gas.

5.7.7 Decisions on what Control Measures are Necessary to Make Reasonable Progress

Based on the four statutory factors, NDEP considers the implementation of LNBs at Kiln 1, and implementation of SNCR at Kilns 1, 3, and 4 as necessary to achieve reasonable progress during the second implementation period of Nevada's Regional Haze SIP. As previously stated, LNBs have recently been installed on Kilns 3 and 4 that have not yet been incorporated into the Apex Plant's current air quality operating permit. NDEP considers the continued use of LNB on Kiln 3 and 4 as necessary to make reasonable progress as well. New NO_x emission limits (and other requirements) that reflect the use LNB and SNCR at Kilns 1, 3, and 4, are derived in the *NDEP Reasonable Progress Determination* for the Apex Plant, found in Appendix B.1.a. These new limits, and other associated requirements, were revised into the Apex Plant's air quality operating permit.

The following requirements are established in the Apex Plant's Authority to Construct Permit issued and enforced by the Clark County Department of Environment and Sustainability as enforceable permit conditions (Table 5-23). The referenced permit conditions below are incorporated by reference into Nevada's Regional Haze SIP Long-Term Strategy for the second implementation period as a source-specific SIP revision for approval. Pages with referenced conditions in the Apex Plant's Authority to Construct permit that NDEP is relying on to achieve reasonable progress for the second implementation period can be found in Appendix A.1.

TABLE 5-23

APEX PLANT ATC PERMIT CONDITIONS INCORPORATED BY REFERENCE

Apex Plant, Authority to Construct Permit for a Major Part 70 Source, Source ID: 3, Clark County DES		
	Citation	Permit Condition
Control Requirements (Facility-Wide)		
NO_x	2.2.1	The control requirements and the NO_X emission reductions proposed in the ATC are permanent and shall not be removed, changed, revised, or modified without the approval of the Nevada Division of Environmental Protection and EPA upon becoming effective.
	2.2.2	Effective no later than two years after the EPA's approval of the controls determination associated with the SIP, the permittee shall install and maintain **low-NO_X burners (LNB) on Kilns 1, 3 and 4** in order to achieve a reduction of **NO_X emissions** (EU: K102, K302, and K402).
	2.2.3	Effective no later than two years after the EPA's approval of the controls determination associated with the SIP, the permittee shall install, operate, and maintain **selective non-catalytic reduction (SNCR) on Kilns 1, 3, and 4 (EUs: K102, K302, and K402) to achieve reduction of NO_X emissions**
Emission Limits (Facility-Wide)		
NO_x	3.2.1	Effective no later than two years after the EPA's approval of the controls determination associated with the SIP, the permittee shall **limit total NO_X emissions from all operating kilns to 3.75 tons per day based on a consecutive 30-day average** (EUs: K102, K202, K302, and K402).
	3.2.2	Effective no later than two years after the EPA's approval of the controls determination associated with the SIP, the permittee **shall limit the combined total NO_X emissions from all operating kilns to 3.59 lb/tlp based on a consecutive 12-month average** (EUs: K102, K202, K302, and K402)
Monitoring, Recordkeeping, and Reporting Requirements		
NO_x	4.1	Monitoring
	4.3.6 4.3.7	Recordkeeping
	4.4.7 4.4.8	Reporting and Notifications

5.7.8 Discussion of Apex Plant Four-Factor Outcome

For Kilns 1, 3, and 4, Low-NO_x Burners and Selective Non-Catalytic Reduction for NO_x control are necessary to achieve reasonable progress. Low NO_x Burners control fuel and air mixing at each burner to reduce peak flame temperature and reduce NO_x formation. Selective Non-Catalytic Reduction injects a reagent, typically urea or anhydrous gaseous ammonia, into the flue gas stream of a system to scrub NO_x emissions.

In the WRAP emission inventories, 2028OTBa2 used reported facility emissions from 2014 to forecast 2028 baseline emissions. Final reductions achieved from the four-factor analysis are greater than what was assumed in the WRAP emission inventories. A comparison of the

2028OTBa2 and final reductions resulting from reasonable progress controls is shown in Table 5-24.

Nevada expects additional NO_x reductions as a result of the four-factor analysis beyond what was assumed in the 2028OTBa2 modeling. The Apex Plant will reduce NO_x emissions by an additional 493 tpy by the end of the second implementation period. New reasonable progress goals for 2028 are derived in Chapter 6 to account for these additional reductions.

TABLE 5-24

APEX MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		**Four-Factor Analysis**		
	2028OTBa2 Emissions		**Baseline Emissions**	**Emissions after Controls**	**Emission Reductions**
Kiln 1					
NOx	294		304	219	85
SO2	107		107	107	0
PM10	2		19	19	0
Kiln 2					
NOx	137		19	19	0
SO2	9		5	5	0
PM10	1		1	1	0
Kiln 3					
NOx	274		154	124	30
SO2	16		18	18	0
PM10	4		16	16	0
Kiln 4					
NOx	647		687	309	378
SO2	18		8	8	0
PM10	1		23	23	0
Total NOx	1,352		1,164	671	493
Total SO2	150		138	138	0
Total PM10	8		59	59	0

5.8 PILOT PEAK PLANT REASONABLE PROGRESS OVERVIEW

For the purpose of determining whether controls at the Pilot Peak Plant are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for the Pilot Peak Plant found in Appendix B.2.a. Pilot Peak's air quality operating permit is incorporated by reference into this SIP in Appendix A.2. Table 5-25 outlines the files referenced in making reasonable progress determinations for the Pilot Peak Plant, and where they can be found in Appendix B.

TABLE 5-25

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR PILOT PEAK

Full Document Title	**Shortened Document Title (used in this document)**	**Date**	**Appendix Location**
Pilot Peak Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Determination*	May 2022	B.2.a
Reasonable Progress Four-Factor Analysis	*GW Analysis*	October 2020	B.2.b
RE: Graymont Pilot Peak Response to Federal Land Managers Comments on Four-Factor Analysis for Regional Haze	*Response Letter 1*	November 13, 2020	B.2.c
RE: Pilot Peak Response to NDEP Request for Additional Information Graymont Western US, Inc.	*Response Letter 2*	April 16, 2021	B.2.d
RE: Graymont Pilot Peak Response to the Initial Control Determination Letter	*Response Letter 3*	October 15, 2021	B.2.e
Class I Air Quality Operating Permit	Permit		A.2

5.8.1 Removing the Pilot Peak Plant from Consideration of Potential New Control Measures

NDEP relied on the Q/d method for source selection by quantifying total facility-wide NO_x, SO_2, and PM_{10} emissions, represented as "Q", reported in the 2014 NEIv2. The Q value was then divided by the distance, in kilometers, between the facility and the nearest Class I area (CIA), represented as "d". The nearest CIA to the Pilot Peak Plant is Jarbidge Wilderness Area at 131 kilometers away. NDEP elected to set a Q/d threshold of 5. As displayed in Table 5-26, using 2014 NEIv2 emissions, the Pilot Peak Plant yielded a Q/d value of 5.15, effectively screening the facility into a four-factor analysis requirement for the second round of Regional Haze in Nevada.

TABLE 5-26

ORIGINAL Q/D DERIVATION FOR PILOT PEAK

NO_x Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	Total Q (NO_x+SO_2 +PM_{10}) [tpy]	Distance from Nearest CIA (Jarbidge WA) [km]	Q/d
523	23	127	673	131	**5.15**

These emissions were pulled from the 2014 NEIv2, based on NO_x emission rates presented in Table 5-27, however, in *Response Letter 2*, Graymont indicated that the emissions reported in the 2014 NEIv2, particularly the NO_x emissions, did not agree with what was submitted by Graymont for Pilot Peak's 2014 Annual Emission Inventory (AEI). Graymont's AEI for Pilot Peak in 2014 resulted in a Total Q of 604 tons per year (tpy), rather than 673, resulting in a Q/d of 4.61 (see Table 5-28). The change in resulting Total Q is primarily due to different NO_x emission rates used to calculate total NO_x emissions. Table 5-29 shows Graymont's calculated NO_x emissions for 2014 to be compared to Table 5-27 that outlines NO_x emissions reported into the 2014 NEIv2.

As seen in Table 5-27, the 2014 NEIv2 emissions calculated NO_x emissions for the Pilot Peak Plant kilns in 2014 using a NO_x emission rate in pound per hour, multiplied by the annual hours of operation for each kiln. This produced facility-wide NO_x emissions at 523 tons per year, resulting in a Q/d of 5.15. Alternatively, as seen in Table 5-29, Graymont calculated NO_x emissions for the Pilot Peak kilns in 2014 using a NO_x emission rate in pounds of NO_x per ton of lime produced, multiplied by the annual lime production rate for each kiln in tons per year. This produced facility-wide NO_x emissions at 459 tons per year, resulting in a Q/d of 4.61.

TABLE 5-27

NDEP-CALCULATED NO_x EMISSIONS FOR PILOT PEAK IN 2014

Unit	NO_x Emission Rate (lb/hr)	Hours of Operation (hr/yr)	NO_x Emissions (tpy)
Kiln 1	47.5	7033	167
Kiln 2	40.1	7033	141
Kiln 3	60.2	7153	215
		Total NO_x Emissions	**523**

TABLE 5-28

UPDATED Q/D DERIVATION FOR PILOT PEAK

NO_x Emissions (tpy)	**SO_2 Emissions (tpy)**	**PM_{10} Emissions (tpy)**	**Total Q (NO_x+SO_2 +PM_{10}) [tpy]**	**Distance from Nearest CIA (Jarbidge WA) [km]**	**Q/d**
459	23	122	604	131	**4.61**

TABLE 5-29

GRAYMONT-CALCULATED 2014 NO_x EMISSIONS FOR UPDATED Q/D

Unit	**NO_x Emission Rate (lb NO_x/ton lime)**	**Lime Production Rate (tons/yr)**	**NO_x Emissions (tpy)**
Kiln 1	2.102	125,313	131.69
Kiln 2	1.302	199,362	129.78
Kiln 3	1.374	287,132	197.32
		Total NO_x Emissions	**459**

NDEP has reviewed the reporting requirements for NO_x emissions in the Pilot Peak Plant's air quality operating permit and confirms that the permitted procedure is to calculate NO_x emissions for each kiln using NO_x emission rates in pounds of NO_x per ton of lime produced, and annual lime production rates in tons per year. Because of this, Graymont no longer places above the set Q/d threshold of 5 and, therefore, is formally screened out of a four-factor analysis requirement and is not considered further for potential new control measures.

A comparison to other reporting years, and their resulting Q/d values, were conducted for years 2015 through 2020. As shown in Table 5-30, the following four operating years (2015-2018) also yield Q/d values below 5, while 2019 and 2020 yield a Q/d value above 5.

TABLE 5-30

Q/D COMPARISON AMONG OPERATING YEARS AT PILOT PEAK

	Facility Emissions (tpy)						
Pollutant	**2014***	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
NO_x	459	406	451	395	418	562	700
SO_2	23	25	15	15	18	19	18
PM_{10}	122	66	75	70	68	77	80
Total	**604**	**497**	**541**	**480**	**504**	**658**	**798**
Q/d	**4.61**	**3.79**	**4.13**	**3.66**	**3.85**	**5.02**	**6.09**

*Updated 2014 emissions submitted in Graymont's AEI

Although emissions reported in 2019 and 2020 yield Q/d values above 5, NDEP does not find that it is reasonable to screen the source back into a four-factor analysis requirement for consideration of potential new measures for the following reasons:

1. Arbitrary Action – NDEP is reluctant to hold the Pilot Peak Plant to a different reporting year than other sources for source selection, as this can be seen as an arbitrary action. All other sources in the state of Nevada were considered for source selection using 2014 emissions, Pilot Peak would be the sole facility that was held to a different reporting year.
2. Emission Inventories – the WRAP states uniformly agreed to conduct source selection through the Q/d analysis using emissions from the NEI so emissions for all Western States could be easily accessed and reviewed by the Western Regional Air Partnership (WRAP) States and members. WRAP agreed to rely on the 2014 NEIv2 for source selection. This was done so that the Representative Baseline emission inventory (based on years 2014-2018) used in the SIP would agree with emissions used for source selection. At the time source selection was conducted, in August of 2019, 2017 and 2020 NEI were not yet available. Even if NDEP elected to rely on 2017 NEI emissions for source selection when it was released, Graymont would have had a Q/d of 3.66. The 2020 NEI is still not yet available.
3. Overall Q/d - considering Q/d values for 2014 through 2020, five of the seven years, or clear majority, show a Q/d value below NDEP's set threshold. The average Q/d across all seven years is 4.45, also falling below the threshold of 5.

Graymont did not provide updated 2014 emissions, subsequently screening them out of the four-factor requirement, until after they had already provided source information for a four-factor analysis (*GW Analysis*). Graymont has volunteered to include all information submitted for a four-factor analysis to demonstrate their efforts in remaining compliant with the requirements of the Regional Haze Rule, but do not intend for the submitted information to be used to consider new potential control measures for the second implementation period of the Regional Haze Rule in Nevada.

Although no new measures were formally considered to achieve reasonable progress at the Pilot Peak kilns, NDEP still evaluated whether any existing measures at the facility were necessary to achieve reasonable progress, outlined in the following sections.

5.8.2 Decisions on What Control Measures are Necessary to Make Reasonable Progress

NDEP evaluated whether existing SO_2, PM_{10}, and NO_x control measures at the Pilot Peak are necessary to make reasonable progress in NDEP's "Reasonable Progress Control Determination" for the Pilot Peak Plant found in Appendix B.2.a.

In this document, a robust weight-of-evidence demonstration is provided for existing SO_2 and PM_{10} control measures at the Pilot Peak Plant to determine that these controls are not necessary to make reasonable progress. Historical and projected emission rates for PM_{10} and SO_2 remain low and consistent, making it reasonable to assume that the source will continue to implement its existing measures and will not increase its emission rate.

For the control of NO_x emissions, Graymont Western has implemented LNBs at all three of the Pilot Peak kilns in recent years. NDEP identifies the continued use of existing LNBs at all three kilns as necessary to make reasonable progress. The determination of the new NOx limits, and other associated requirements, that reflect the use of Low-NO_x Burners at all Pilot Peak kilns is provided in NDEP's "Reasonable Progress Control Determination" for Pilot Peak.

The following requirements are established in the Pilot Peak Plant's air quality operating permit (Permit No. AP3274-1329.03) as enforceable permit conditions (Table 5-31). The referenced permit conditions below are incorporated by reference into Nevada's Regional Haze SIP Long-Term Strategy for the second implementation period as a source-specific SIP revision for approval. Pages with referenced conditions in the Pilot Peak Plant's current air quality permit that NDEP is relying on to achieve reasonable progress for the second implementation period can be found in Appendix A.2.

TABLE 5-31

PILOT PEAK PLANT PERMIT CONDITIONS INCORPORATED BY REFERENCE

Pilot Peak Plant, Permit No. AP3274-1329.03		
	Citation	Permit Condition
Kiln 1 (System 10 – Kiln #1 Circuit)		
NO_x	IV.I.1.a	Emissions from **S2.031 through S2.033** shall be controlled by a baghouse (D-85) and **Low-NOx Burners.**
	IV.I.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from **the exhaust stack of baghouse (D-85)** the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of **NOx** to the atmosphere shall not exceed 101.4 pounds per hour, based on a 30-day rolling average period.
	V.B-C	**NOx (CEMS) Requirements for System 10** (S2.031, S2.032, and S2.033), **System 13** (S2.036, S2.037, S2.038), and **System 17** (S2.042, S2.043, S2.044)
	IV.I.4.q IV.I.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements
Kiln 2 (System 13 – Kiln #2 Circuit)		
NO_x	IV.L.1.a	Emissions from **S2.036 through S2.038** shall be controlled by a baghouse (D-285) and **Low-NOx Burners.**
	IV.L.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from **the exhaust stack of baghouse (D-285)** the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of **NOx** to the atmosphere shall not exceed 107.4 pounds per hour, based on a 30-day rolling average period.
	V.B-C	**NOx (CEMS) Requirements for System 10** (S2.031, S2.032, and S2.033), **System 13** (S2.036, S2.037, S2.038), and **System 17** (S2.042, S2.043, S2.044)
	IV.L.4.q IV.L.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements
Kiln 3 (System 17 – Kiln #3 Circuit)		
NO_x	IV.Q.1.a	Emissions from **S2.042 through S2.044** shall be controlled by a baghouse (D-385) and **Low-NOx Burners.**
	IV.Q.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from **the exhaust stack of baghouse (D-385)** the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of **NOx** to the atmosphere

		shall not exceed 143.7 pounds per hour, based on a 30-day rolling average period.
	V.B-C	**NOx (CEMS) Requirements for System 10** (S2.031, S2.032, and S2.033), **System 13** (S2.036, S2.037, S2.038), and **System 17** (S2.042, S2.043, S2.044)
	IV.Q.4.q IV.Q.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements

5.4.4 Discussion of Pilot Peak Plant Four-Factor Outcome

Although NO_x emission limits will be reduced within the source's air quality operating permit, these levels have already been achieved in practice over the past several years, and beyond the scope of the second implementation period of the Regional Haze Rule for Nevada. Because of this, there are no expected emission reductions within the WRAP emission inventories, or as a result of the final four-factor analysis. An emissions summary is provided in Table 5-32.

Although there is a slight difference in emissions between 2028OTBa2 and the Emissions After Controls inventories, this is a result of different baseline emissions used and not because of reductions achieved from add-on controls considered in the four-factor analysis. Because of this, there will be no adjustments made to the reasonable progress goals provided by the WRAP to reflect additional reductions at the Pilot Peak Plant.

TABLE 5-32

PILOT PEAK MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		**Baseline Emissions**	**Emissions after Controls**	**Emission Reductions**
Kiln 1					
NOx	167		135	135	0
SO2	3		1	1	0
PM10	18		17	17	0
Kiln 2					
NOx	141		173	173	0
SO2	6		1	1	0
PM10	31		25	25	0
Kiln 3					
NOx	215		207	207	0
SO2	14		4	4	0
PM10	5		51	51	0
Total NOx	523		515	515	0
Total SO2	23		6	6	0
Total PM10	54		93	93	0

5.9 FERNLEY PLANT FOUR FACTOR ANALYSIS

For the purpose of determining whether controls at the Fernley Plant are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for the Fernley Plant found in Appendix B.4.a. Table 5-33 outlines the files referenced in making reasonable progress determinations for the Pilot Peak Plant, and where they can be found in Appendix B.

TABLE 5-33

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR FERNLEY

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Fernley Plant Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Control Determination*	March 2022	B.4.a
Regional Haze – Four Factor Analysis	*NCC Analysis*	October 2020	B.4.b
RE: Regional Haze Four Factor Analysis SO_2 Response to NDEP Comments	*Response Letter 1*	November 3, 2020	B.4.c
RE: Regional Haze Four Factor Analysis SO_2 Response to NDEP Comments	*Response Letter 2*	January 7, 2021	B.4.d
Regional Haze Email	*NCC Email*	September 20, 2019	B.4.e

Nevada Cement Company's (NCC) Fernley Plant is a Portland cement manufacturing plant located in Fernley, Nevada, consisting of two coal-fired and/or natural gas-fired long-dry process kilns. Portland cement produced by NCC is a cementitious, crystalline compound composed primarily of calcium, aluminum, and iron silicates. Both kilns are rated at 30.55 tons per hour of clinker, translating to about 267,500 tons per year clinker for each kiln, or 535,000 tons per year plantwide.

Both kilns at the Fernley Plant currently operate baghouses for the control of particulate matter. NDEP considers the existing baghouses for both kilns as existing effective controls, therefore, additional PM_{10} control measures were not considered for the Fernley Plant kilns. However, NDEP considers the continued use of the existing baghouses at both kilns as necessary to achieve reasonable progress.

When considering existing and potential new SO_2 and NO_x control measures, it is important to note that the Fernley Plant is currently bound to the requirements of a USEPA Consent Decree to control NO_x and SO_2 emissions, which can be found via the following links:

United States of America v. Nevada Cement Company, Civil Action No. 3:17-cv-00302-MMD-WGC

https://www.justice.gov/enrd/consent-decree/file/1089586/download

https://www.justice.gov/enrd/consent-decree/file/1089596/download

To control SO_2 emissions, the Consent Decree requires that both kilns at the Fernley Plant emit no more than 1.1 pound of SO_2 per ton of clinker. The facility relies on inherent scrubbing of SO_2 emissions within the cement kilns and has since installed a Dry Sorbent Injection system to assist in achieving the relevant emission limits for both kilns. The Consent Decree ultimately requires that the 1.1 pound of SO_2 per ton of clinker emission rate be incorporated into the facility's Title V operating permit.

To control NO_x emissions, the facility is required to install Selective Non-Catalytic Reduction (SNCR), followed by Low-NO_x Burners. Currently, the facility has installed SNCR on both kilns and is in the demonstration period. As stated in Appendix A of the Consent Decree, after the demonstration period, the source is to submit a demonstration report for each kiln's SNCR performance. A final 30-day rolling average emission limit for NO_x for both kilns is then derived from the findings of the demonstration report. Once approved by EPA, or an alternative 30-day rolling average emission limit is provided by EPA, the new NO_x limit associated with the SNCR systems for both kilns is permanently incorporated into the Fernley Plant's NDEP air quality operating permit. The same procedure is required for the implementation of Low-NO_x Burners for each kiln.

NDEP does not consider the installation and continued use of SNCR and Low-NO_x Burners at both Fernley Plant kilns as necessary to achieve reasonable progress, as NDEP is incapable of determining emissions limits, associated requirements, and compliance schedules for the NO_x controls in a manner that would satisfy the applicable SIP requirements.

The Consent Decree also required the installation and continued use of Continuous Emission Monitoring Systems (CEMS) for both kilns to measure and monitor SO_2 and NO_x emissions. The facility has since implemented CEMS for both kilns successfully and relies on CEMS for SO_2 and NO_x emissions reporting.

NDEP is relying on the referenced Consent Decree to screen the facility out of further consideration of potential new control measures, as the outcome of the Consent Decree will inherently make both kilns BACT for NO_x, SO_2, and PM_{10} emissions. Once NCC has developed and finalized all associated limits to the consent decree controls, it is required that these new limits be incorporated into the facility's Title V permit, making the controls federally enforceable and permanent.

NDEP concludes that the consent decree controls for NO_x and SO_2 are not necessary to achieve reasonable progress as these new consent decree controls, and associated limits, will become federally enforceable and permanent through the source's Title V operating permit, as required by the USEPA Consent Decree, regardless of whether they are included in Nevada's Long-Term Strategy for the second implementation period of Regional Haze as necessary to achieve reasonable progress. Furthermore, anticipated reductions from the implementation of NO_x controls and achievement of new SO_2 limits required by the consent decree were not included in the 2028 RPGs developed in Chapter 6 for Jarbidge WA.

Although the Fernley Plant was not required to conduct a four-factor analysis for potential new control measures, the facility was asked to evaluate the continuous use of the facility's existing DSI system, as opposed to occasional use, considering the four statutory factors to achieve additional SO_2 emission reductions.

5.9.1 Baseline Emissions

The SO_2 emissions baseline used in the considering continuous operation of the existing DSI system is summarized in Table 5-34. These baseline emissions represent available SO_2 emissions that could be reduced after DSI has already been used to meet the SO_2 emission limit requirements listed in the consent decree.

TABLE 5-34

FERNLEY FOUR-FACTOR ANALYSIS BASELINE SO_2 EMISSIONS

Kiln	Baseline SO_2 Emissions (tpy)
1	114.6
2	106.8

5.9.2 Characterization of Cost of Compliance

Cost-effectiveness values for operating the existing DSI system at full capacity, provided in Table 5-35, are focused on achievable SO_2 reductions based on the baseline SO_2 emissions and assumed control efficiency of the control. A 30% SO_2 reduction is assumed, resulting in a cost-effectiveness value of $30,066 per ton of SO_2 reduced for Kiln 1 and $30,140 per ton of SO_2 reduced for Kiln 2.

TABLE 5-35

FERNLEY FOUR-FACTOR ANALYSIS COST-EFFECTIVENESS SUMMARY

Control	Kiln	Baseline SO_2 Emissions (tpy)	Assumed Control Efficiency	Tons SO_2 Reduced (tpy)	Total Annualized Cost	Cost-Effectiveness
Continuous use of DSI	1	114.6	30%	34.4	$1,034,274	$30,066 /ton
	2	106.8	30%	32.0	$964,491	$30,140 /ton

5.9.3 Characterization of Time Necessary for Compliance

Approximately 4 months is required to procure, build, install, and shakedown the new equipment for proper engineering.

5.9.4 Characterization of Energy and Non-Air Quality Environmental Impacts

In determining energy and non-air quality environmental impacts, NDEP is relying on NCC's statement provided in Section 5.6 of the NCC Analysis that states:

"The use of DSI full time (8,760 hr/yr) will have an energy penalty in terms of electricity needed to operate the larger blower (50 hp). The electricity requirement for the DSI system is approximately 39kW per hour (343,889 kW/yr) which equates to $19,051 per year... Kiln 1 and Kiln 2 are currently equipped with an as needed DSI system for SO_2 control. The lime reagent used in a DSI system reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing fabric filter particulate control systems and either returned to the systems for reuse or removed from the systems as nonhazardous solid waste. Collateral environmental impacts associated with the DSI system include increased solid waste generation. Additionally, the operation of the DSI storage vessel's baghouse will emit an additional 0.2 tpy of PM (lime emissions)."

The additional electricity cost outlined above is included in the source's analysis for the cost of compliance. Although the control would require additional electricity to operate at full capacity, NDEP does not find this to be sufficient to warrant a no control determination. The calcium sulfate and calcium sulfite solids are either recycled back into the system or properly disposed of. This does not pose a threat to the surrounding non-air environment. Although there is a 0.2 tpy increase in PM emissions as a result of this control, adding this increase to the total reductions achieved by the control would not be impactful in the analysis.

5.9.5 Characterization of Remaining Useful Life of the Source

The cost analysis assumes a 20-year life for the DSI system on both kilns when calculating the annualized capital costs of the upgraded DSI system.

5.9.6 Decisions on what Control Measures are Necessary to Make Reasonable Progress

Considering the four statutory factors outlined above, NDEP does not consider the upgrade of the existing DSI system to operate at full capacity for both kilns as necessary to achieve reasonable progress. No other potential new control measures are considered for the Fernley Plant.

As stated above, NDEP does not consider the anticipated NO_x and SO_2 emission reductions resulting from the ongoing USEPA consent decree as necessary to achieve reasonable progress during the second implementation period.

NDEP also does not consider the existing baghouses used to achieve current PM_{10} emission limits listed in the facility's air quality operating permit as necessary to achieve reasonable progress. NDEP is relying on consistent historical emissions and referencing PM_{10} emissions limits (Table 5-36) listed in the Fernley Plant's permit, Permit No. AP3241-0387.02. A robust demonstration with supporting documentation is included in the source's Control Determination in Appendix B.

TABLE 5-36

FERNLEY PLANT PERMIT LIMITS FOR PM_{10}

Kiln	Pollutant	Limit (lb/hr)	Limit (tpy)
1	PM_{10}	14.83	64.96
2	PM_{10}	14.83	64.96

5.9.7 Discussion of Fernley Plant Four-Factor Outcome

Although there is a slight difference in emissions between 2028OTBa2 and the Emissions After Controls inventories, as shown in Table 5-37, this is a result of different baseline emissions used and not because of reductions achieved from add-on controls considered in the four-factor analysis. Both 2028OTBa2 and the Emissions After Controls inventories use the same emission factors, however, 2028OTBa2 assumed actual operating hours reported in 2014 and Emissions After Controls assumed 8760 operating hours. Because of this, there will be no adjustments made to the reasonable progress goals provided by the WRAP to reflect additional reductions at the Fernley Plant.

TABLE 5-37

FERNLEY MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		Baseline Emissions	Emissions after Controls	Emission Reductions
Kiln 1					
NOx	544		1307	1307	0
SO2	62		167	167	0
PM10	58		125	125	0
Kiln 2					
NOx	554		1261	1261	0
SO2	64		167	167	0
PM10	57		125	125	0
Total NOx	1,098		2568	2568	0
Total SO2	126		334	334	0
Total PM10	115		250	250	0

5.10 TS POWER PLANT REASONABLE PROGRESS ANALYSIS

For the purpose of determining whether controls at the TS Power Plant are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for the TS Power Plant found in Appendix B.3.a. Table 5-38 outlines the files referenced in making reasonable progress determinations for the TS Power Plant, and where they can be found in Appendix B.

TABLE 5-38

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR TS POWER

Full Document Title	**Shortened Document Title (used in this document)**	**Date**	**Appendix Location**
TS Power Plant Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Control Determination*	March 2022	B.3.a
Reasonable Progress Analysis	*NNEI Analysis*	December 10, 2019	B.3.b

TS Power, built in 2008, was also removed from the four-factor requirement as the facility has state of the art Best Available Control Technology (BACT) that was included in the original design. It was confirmed that a four-factor analysis would not result in any cost-effective additional controls in the facility's Reasonable Progress Report submitted to NDEP (located in Appendix B.3.b) during the second implementation of the Regional Haze Rule. The TS Power Plant has one pulverized coal, dry bottom boiler with a gross capacity of 220 MW. Table 5-39 lists the existing controls that reduce visibility impairing pollutants at the facility, along with the corresponding BACT emission limits that can be found in the facility's air quality operating permit (Permit No. AP4911-2502).

Note that there are two BACT emission limits for SO_2, depending on the sulfur content of the coal burned. As seen in the below table, an SO_2 emission limit of 0.065 pounds per million british thermal units and minimum SO_2 control efficiency of 91% is enforced when the unit burns coal with a sulfur content less than 0.45%. When the unit is combusting coal with a sulfur content equal to or greater than 0.45%, the emission limit is raised to 0.09 pounds per million british thermal units, however, the increase in emissions is offset by an increased minimum SO_2 control efficiency of 95%.

TABLE 5-39

TS POWER PLANT BACT CONTROLS AND EMISSION LIMITS

Pollutant	Control	BACT Emission Limit (lb/MMBtu)
NO_x	Low-NO_x Burners Over Fired Air Selective Catalytic Reduction	0.067
SO_2	Lime Spray Dryer While combusting coal with a sulfur content equal to or greater than 0.45%	0.09 (95% minimum SO_2 removal efficiency required)
	Lime Spray Dryer While combusting coal with a sulfur content less than 0.45%	0.065 (91% minimum SO_2 removal efficiency required)
PM_{10}	Pulse Jet Fabric Filter Dust Collector	0.176

As stated above, the TS Power Plant has been determined as already operating BACT (best available control technology) controls for NO_x, SO_2, and PM_{10} emissions. In NDEP's "Reasonable Progress Control Determination" for TS Power, a robust weight-of-evidence demonstration is provided for existing NO_x, SO_2, and PM_{10} control measures at the TS Power Plant to determine that these controls are not necessary to make reasonable progress. Historical and projected emission rates for NO_x, SO_2, and PM_{10} remain low and consistent, making it reasonable to assume that the source will continue to implement its existing measures and will not increase its emission rates.

5.4.7 Cumulative Emissions Reductions

Significant emission reductions are expected to achieve reasonable progress for the second implementation period of Nevada's Regional Haze SIP. Emission reductions for all facilities conducting a four-factor analysis were estimated by both WRAP and NDEP. WRAP estimates were developed for modeling inventories, with 2028OTBa2 data using updated 2014 emissions. In NDEP's four-factor analyses calculations, baseline emissions were typically derived from more recent reporting years (e.g. average annual emissions from 2016 to 2018) and controlled emissions derived from the assumed control efficiency of any control that is cost-effective and necessary to achieve reasonable progress.

Emission reductions calculated from NDEP's four-factor analyses are more accurate than what was estimated for WRAP modeling, and provide a better image of achieved emission reductions as a result of Nevada's efforts during the second implementation period. WRAP modeling inventories used less recent emissions data for the baseline and only estimates of controlled emissions. Table 5-40 compares the total emission reductions between baseline and controlled emissions for WRAP modeling and NDEP's four-factor analyses. Total emissions across the four-factor sources were estimated at 7,964 tpy in WRAP 2028OTBa2 modeling, while NDEP's four-factor data indicates total emissions across four-factor sources at 5,139 tpy. This translates to a difference of nearly 3,000 tpy.

Figure 5-1 compares NDEP's calculation of baseline and controlled emissions among the sources in Nevada considered for reasonable progress controls. SO_2 emissions show a total reduction of 2,313 tons per year, NO_x emissions show a total reduction of 2,239 tons per year, and PM_{10} emissions show a total reduction of 60 tons per year. Referring to more current and accurate baseline emissions used in the four-factor analyses, Nevada expects a total reduction in primary visibility impairing pollutants (SO_2, NO_x, and PM_{10}) of 4,612 tons per year as a result of the four-factor analyses conducted to achieve reasonable progress for the second round.

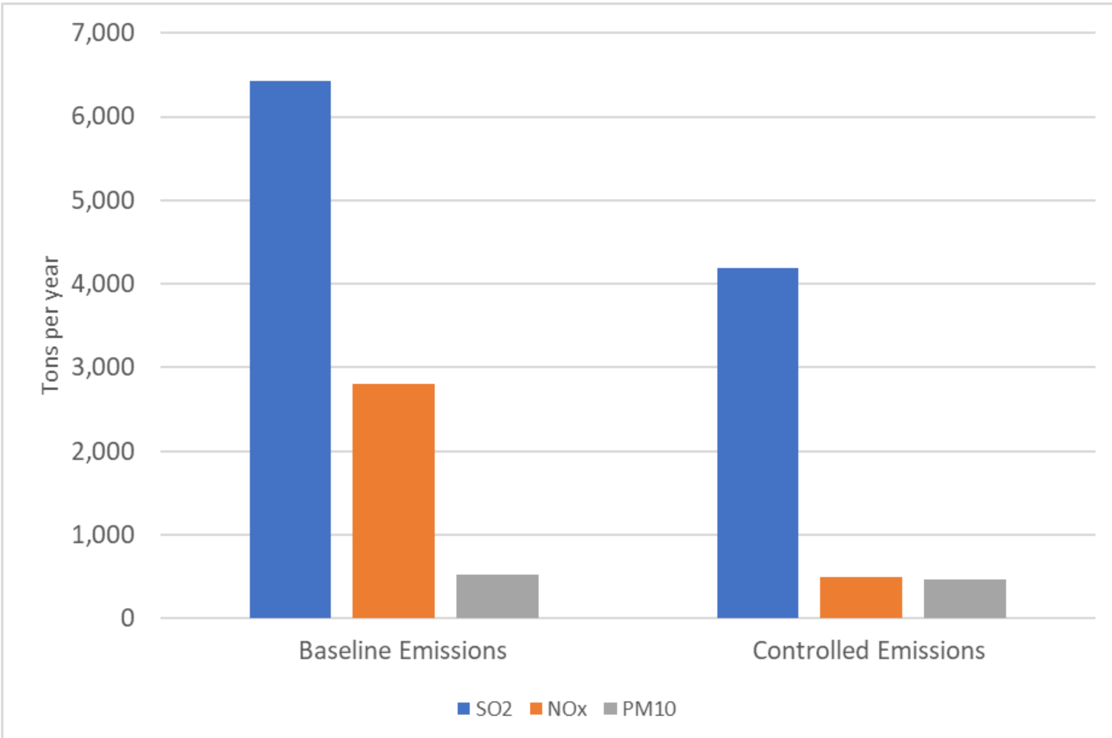
TABLE 5-40

TOTAL MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		**Baseline Emissions**	**Emissions after Controls**	**Emission Reductions**
Valmy					
NOx	1583		1746	0	1746
SO2	2,281		2,313	0	2313
PM10	77		60	0	60
Tracy					
NOx	503		434	434	0
SO2	11.5		12	12	0
PM10	59		59	59	0
Apex					
NOx	1,352		1164	671	493
SO2	150		138	138	0
PM10	8		59	59	0
Pilot Peak					
NOx	523		515	515	0
SO2	23		6	6	0
PM10	54		93	93	0
Fernley					
NOx	1,098		2568	2568	0
SO2	126		334	334	0
PM10	115		250	250	0
Total					
NOx	5,059		6427	4188	2239
SO2	2,592		2803	490	2313
PM10	313		521	461	60
Grand Total	7,964		9,751	5,139	**4,612**

FIGURE 5-1

BASELINE AND CONTROLLED EMISSIONS COMPARISON FOR REASONABLE PROGRESS DURING THE SECOND IMPLEMENTATION PERIOD



5.11 ENVIRONMENTAL JUSTICE IMPACT ANALYSIS OF FOUR-FACTOR SOURCES

The Regional Haze Rule requires that states consider non-air quality environmental impacts as one of the four statutory factors when evaluating potential additional controls. Consideration of Environmental Justice (EJ) and the impact control decisions may have on potentially vulnerable communities falls within this category. NDEP has modeled its EJ analysis after the EJ analysis found in Oregon's Regional Haze Plan Support Document[1]. In NDEP's Regional Haze EJ analysis, communities within a 3-mile and 10-mile radius of each source identified by NDEP's Q/d source screening method were examined for any patterns of disproportionate burden of environmental pollution on vulnerable communities using the 2020 version of EPA's EJSCREEN tool.

This version of EJSCREEN uses the 2014-2018 five-year American Community Survey data for demographic indicators:

- People of Color Population (%)
- Low Income Population (%)
- Linguistically Isolated Population (%)
- Population With Less Than High School Education (%)
- Population Under 5 Years of Age (%)
- Population Over 64 Years of Age (%)

These indicators are standard demographic indicators commonly used by EPA and other state agencies when considering Environmental Justice impacts. Each indicator is represented in percentage of the total recorded population within the designated radius around each facility.

For each facility, NDEP tallied a “1” if the value of that indicator was above the statewide average, or a “0” if the value was below the statewide average. Figures 5-2 and 5-3 below show the number of indicators for which the community within a facility was above the statewide average, achieving a maximum of 6 and minimum of 0. If a census block was only partially contained within the radius of the facility, then the value for that census block group was scaled to the proportion of the block group within the circle. An outline of the demographic indicator values recorded within the radius of each facility is included in the Tables 5-41 and 5-42 below and compared to the statewide average. Indicators that are above the statewide average are highlighted and represent a tally of “1.” An “N/A” value indicates a census population of 0 in that facility’s radius. A facility with a vulnerability score of 4 or more would indicate a significant impact on vulnerable communities and would require further consideration in deciding what controls at the facility may be necessary for reasonable progress in Nevada’s second implementation period of the Regional Haze Rule.

FIGURE 5-2

NUMBER OF SOCIOECONOMIC INDICATORS FOR COMMUNITIES WITHIN 3 MILES OF A FOUR-FACTOR FACILITY

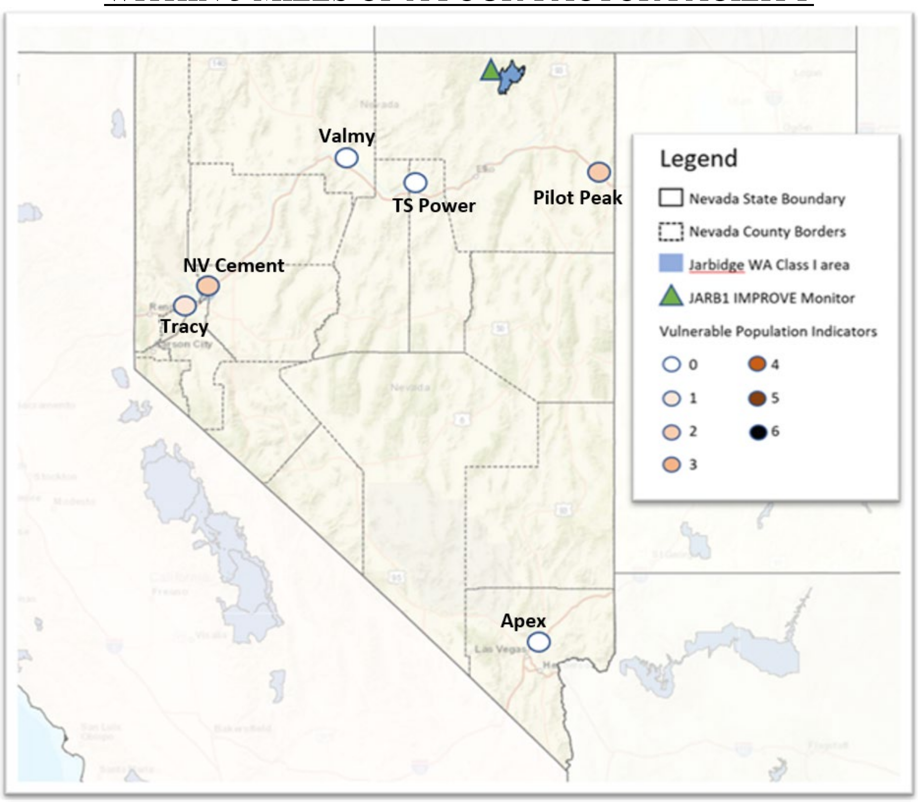


TABLE 5-41

DEMOGRAPHIC INDICATORS FOR EACH FACILITY
COMPARED TO STATEWIDE AVERAGES USING A 3-MILE RADIUS

Demographic Indicator	North Valmy GS	Tracy GS	TS Power Plant	Statewide Ave.
Population Count	0	16	2	3,100,00
People of Color	N/A	14%	20%	50%
Low Income	N/A	16%	7%	34%
Linguistically Isolated	N/A	0%	0%	6%
< High School Education	N/A	4%	8%	14%
< 5 Years of Age	N/A	2%	5%	6%
> 64 Years of Age	N/A	39%	12%	15%
Demographic Indicator	Fernley Plant	Apex Plant	Pilot Peak Plant	Statewide Ave.
Population Count	12,316	0	2	3,100,00
People of Color	32%	N/A	44%	50%
Low Income	33%	N/A	51%	34%
Linguistically Isolated	0%	N/A	0%	6%
< High School Education	13%	N/A	25%	14%
< 5 Years of Age	7%	N/A	4%	6%
> 64 Years of Age	17%	N/A	11%	15%

FIGURE 5-3

NUMBER OF SOCIOECONOMIC INDICATORS FOR COMMUNITIES
WITHIN 10 MILES OF A FOUR-FACTOR FACILITY

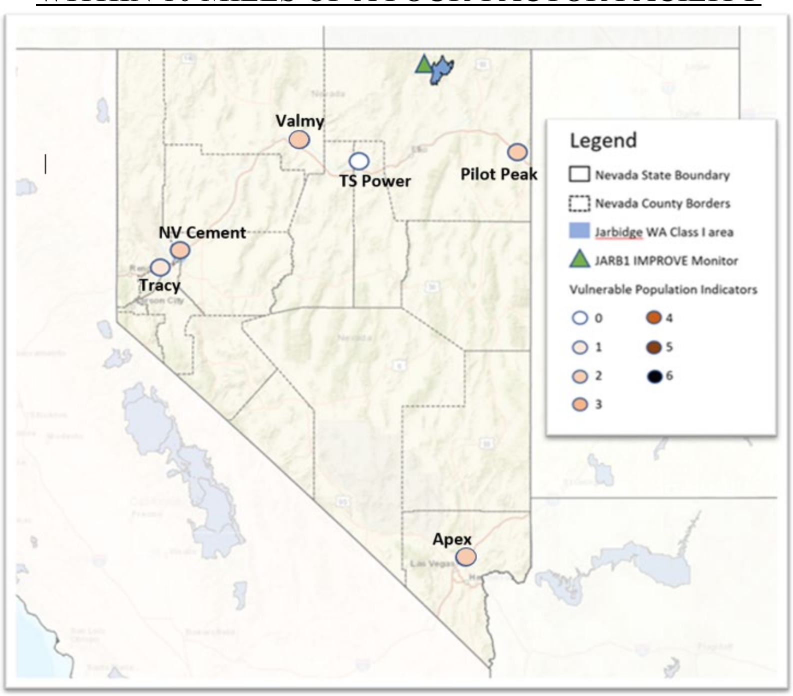


TABLE 5-42

DEMOGRAPHIC INDICATORS FOR EACH FACILITY
COMPARED TO STATEWIDE AVERAGES USING A 10-MILE RADIUS

Demographic Indicator	North Valmy GS	Tracy GS	TS Power Plant	Statewide Ave.
Population Count	83	30,047	21	3,100,00
People of Color	35%	26%	20%	50%
Low Income	44%	13%	7%	34%
Linguistically Isolated	4%	2%	0%	6%
< High School Education	27%	5%	8%	14%
< 5 Years of Age	4%	5%	5%	6%
> 64 Years of Age	12%	20%	12%	15%
Demographic Indicator	Fernley Plant	Apex Plant	Pilot Peak Plant	Statewide Ave.
Population Count	20,956	78	11	3,100,00
People of Color	28%	57%	44%	50%
Low Income	29%	35%	51%	34%
Linguistically Isolated	1%	5%	0%	6%
< High School Education	11%	3%	25%	14%
< 5 Years of Age	7%	0%	4%	6%
> 64 Years of Age	17%	0%	11%	15%

The six facilities that underwent the four-factor review are generally located in sparsely populated rural areas. Among the six sources, only the Nevada Cement Fernley Plant has a significantly large population within a 3-mile radius. Two sources, North Valmy and TS Power, have no population. The Lhoist Apex facility located just outside the Las Vegas metropolitan area, has very few residents living nearby. Similarly, the Tracy plant near the Reno/Sparks area is situated where there are few residents. Of the four sources that have a reported population, a maximum of two indicators were recorded above the statewide average.

When evaluating the same facilities at a 10-mile radius, the conclusion remains relatively the same, with a few changes. North Valmy Generating Station and the Apex Plant now have a population value with corresponding EJSCREEN Tool data. With this, both North Valmy and Apex Plant show two indicators that are above the statewide average. Fernley Plant's population nearly doubles with the larger radius; however, the two indicators of concern remain the same. Tracy Generating Station's population increased by nearly 30,000 people and demonstrates the benefit of evaluating larger distances around facilities, however, the sole indicator of concern remains the same. Of all six sources, it remains true that a maximum of two indicators were recorded above the statewide average for each source.

In considering the communities within a 3-mile and 10-mile radius of Nevada's Regional Haze sources, NDEP concludes that there is no significant impact on vulnerable communities that would further provide evidence that a control currently not being considered as "necessary for reasonable progress" should be installed.

Exhibit 4

Regional Haze
Stakeholder Outreach Webinar #2

Mark Jones, Michael Baca, Neal Butt, Rhett Zyla - New Mexico Environment Department Air Quality Bureau

Ed Merta, Andrew Daffern - City of Albuquerque Environmental Health Department

Photo credit Rhett Zyla #IamNMED

What we will cover today

- Overview of Western regional planning ("Storyboard")
- Show examples of Class I Area monitor data
- Update on planning progress of NMED/COA
- Discuss four-factor analyses of control measures
- Modeling impacts
- Solicit feedback from stakeholders

WRAP Regional Planning

- The West is different: distinctive regional concerns
- Western Regional Air Partnership:
  - Provides data/technical services for Western states
  - Forum for consultation to develop consensus
    - States, Tribes, EPA, & Federal Land Managers
- WRAP "Storyboard"
  - Overview of Western perspective on Regional Haze
  - Accessible content, abundant visuals
  - https://views.cira.colostate.edu/wrap_rhpwg_Storyboard_draftNov20_2019/
  - Let's take a (brief) look!

WRAP Regional Planning Area

WRAP Stages of Planning Process

- Red highlight = SIP work currently underway

Step 1	**Ambient data analysis**
Step 2	**Determination of affected Class I Areas in other states**
Step 3	**Selection of emission sources for control measure analysis**
Step 4	**Characterization of four factors for control measures analysis**
Step 5	**Decisions on control measures necessary for reasonable progress**
Step 6	**Regional modeling to project 2028 reasonable progress goals (RPGs)**
Step 7	**Compare RPGs to baseline conditions and uniform rate of progress**
Step 8	**Additional requirements: emissions, monitoring, reporting, etc.**

Regional Haze Info and Resources

- NMED website: https://www.env.nm.gov/air-quality/reg-haze/
  - Regional Haze background information
  - View fall 2019 webinar/sign up for listserv
  - List of sources subject to four factor analysis
  - Drafts of four factor analyses submitted by facilities
  - Regional Haze planning schedule
- WRAP Regional Haze website: https://www.wrapair2.org/RHPWG.aspx
- WRAP Technical Support System: https://views.cira.colostate.edu/tssv2/

ONE ALBUQUERQUE environmental health

Ambient Monitor Data

- IMPROVE network data: Visibility at NM C1As

Visibility Progress Summary: New Mexico

New Mexico - Class I Area Visibility Trends Summary Most Impaired Days *(defined by EPA guidance*[1]*)*					
Class I Area	**Representative IMPROVE Monitor**	**IMPROVE 2000-2004**	**IMPROVE 2008-2012**	**IMPROVE 2014-2018**	**Estimated Natural Conditions 2064**
Bandelier National Monument	BAND1	9.7 *dv*	9.3 *dv*	8.4 *dv*	4.6 *dv*
Bosque del Apache National Wildlife Refuge Wilderness	BOAP1	11.6 *dv*	11.2 *dv*	10.5 *dv*	5.4 *dv*
Carlsbad Caverns National Park	GUMO1	14.6 *dv*	12.9 *dv*	12.6 *dv*	4.8 *dv*
Gila Wilderness Area	GICL1	9 *dv*	8.3 *dv*	7.6 *dv*	4.2 *dv*
Pecos Wilderness Area	WHPE1	7.3 *dv*	6.7 *dv*	6 *dv*	3.5 *dv*
Salt Creek National Wildlife Refuge Wilderness	SACR1	16.5 *dv*	15.3 *dv*	15 *dv*	5.5 *dv*
San Pedro Parks Wilderness Area	SAPE1	7.7 *dv*	7 *dv*	6.4 *dv*	3.3 *dv*
Wheeler Peak Wilderness Area	WHPE1	7.3 *dv*	6.7 *dv*	6 *dv*	3.5 *dv*
White Mountain Wilderness Area	WHIT1	11.3 *dv*	10.5 *dv*	10 *dv*	4.9 *dv*

1) U.S. EPA. December 2018. Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. EPA-454/R-18-010

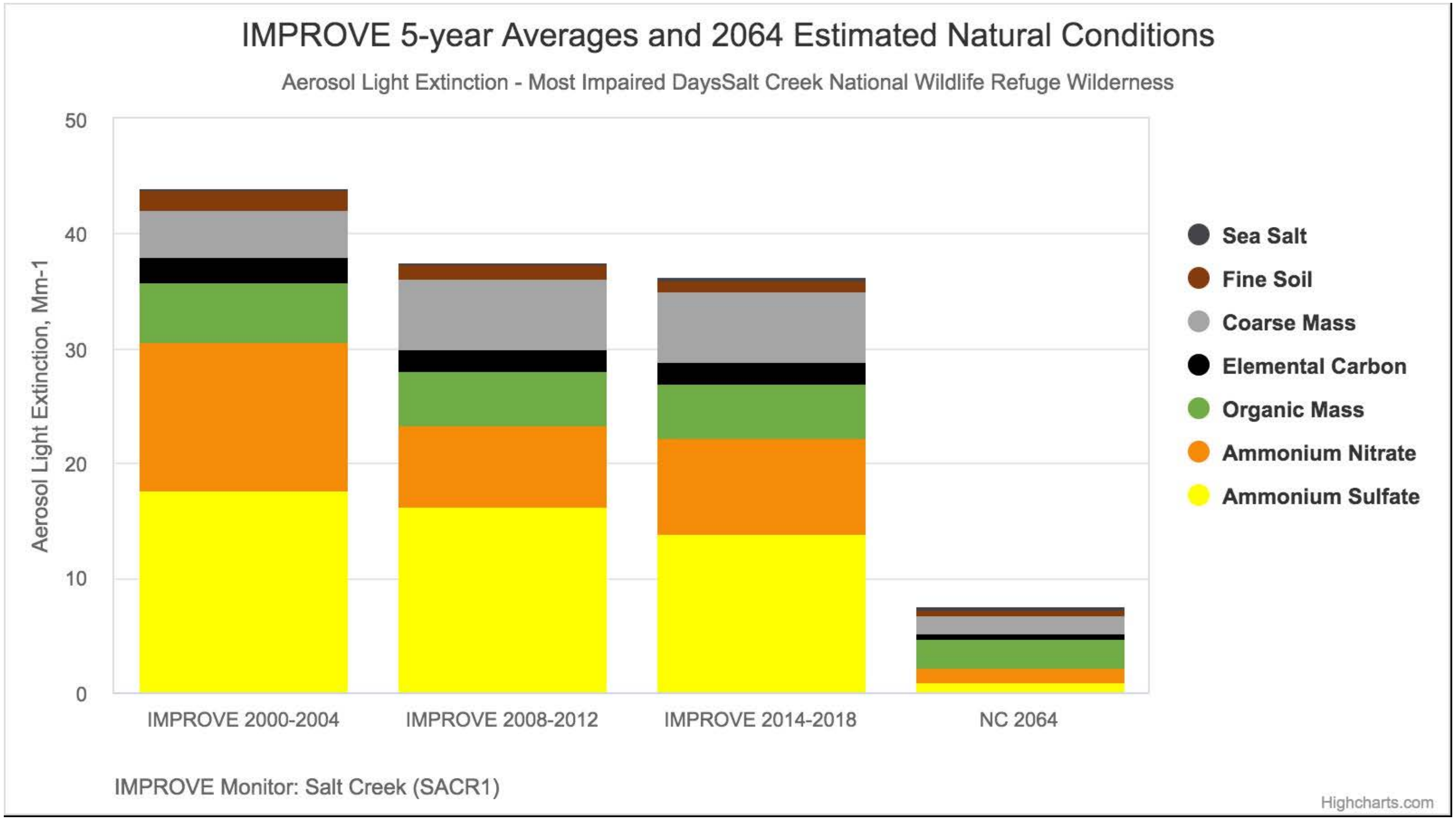
https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx

Requirement:

40 CFR § 51.308(f)(1)(i) to (v)

Ambient Monitor Data

- IMPROVE network data: speciated contributions

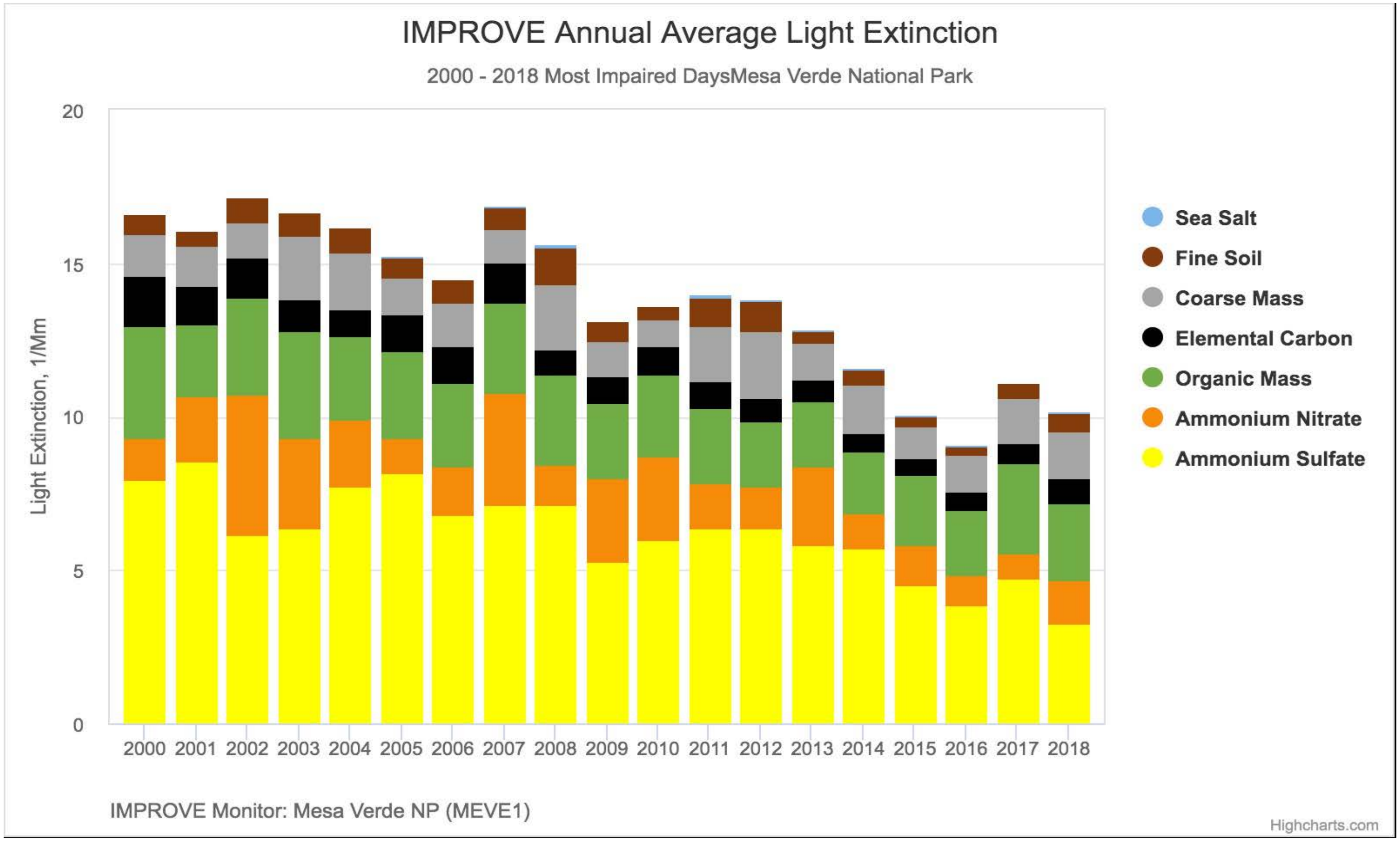


https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx

Requirement:
40 CFR § 51.308(f)(2)(iii)

Ambient Monitor Data

- IMPROVE network data: other states



https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx

Requirement:

40 CFR § 51.308(f)(2)(ii)

Source Selection Process

- **"Source selection"**
  - Determine which facilities will be subject to analysis of potential new control measures (Four-Factor Analysis)
- **NMED/EHD process based on WRAP guidance**
  - Target key drivers of visibility impairment: SO_2 and NO_X
  - For each Title V facility, calculate the following:
    - Q = reported SO_2 + NO_X emissions (tons, 2016)
    - d = distance (kilometers) to nearest Class I Area
    - Q/d = potential visibility impact of facility
  - Rank all facilities highest to lowest Q/d
  - Identify facilities accounting for 80% of SO_2 + NO_X
  - These facilities are subject to Four-Factor Analysis
  - Minor & Area sources not considered for evaluation

New Mexico Four-Factor Facilities

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San PedroParks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

*Located in Bernalillo County outside of NMED Jurisdiction.

Four-factor analysis documentation available at:
https://www.env.nm.gov/air-quality/four_factor_analysis-reports/

What is a Four-Factor Analysis?

- Identify additional controls that are technically feasible for equipment that emits ≥ 5 tpy SO_2/NO_X
- Assess the four factors for feasible controls:
  - Cost of compliance
  - Time necessary for compliance
  - Energy & non-air environmental impacts
  - Remaining useful life of the source
- Calculate cost effectiveness of each control
  - Expressed as $ per ton of annual emission reduction achieved
  - Anticipated cost effective threshold: ≤ $7,000 per ton/year
  - Case by case basis for final determination

ONE ALBUQUERQUE environmental health

Equipment Under Evaluation

- Oil and gas mid-stream facilities
  - Reciprocating internal combustion engines (RICE)
  - Turbines & boilers
  - Amine units & sulfur recovery units
  - Flares
- Power plants
  - Boilers & turbines
- Cement manufacturing
  - Kilns

ONE ALBUQUERQUE environmental health

Example of Potential Controls

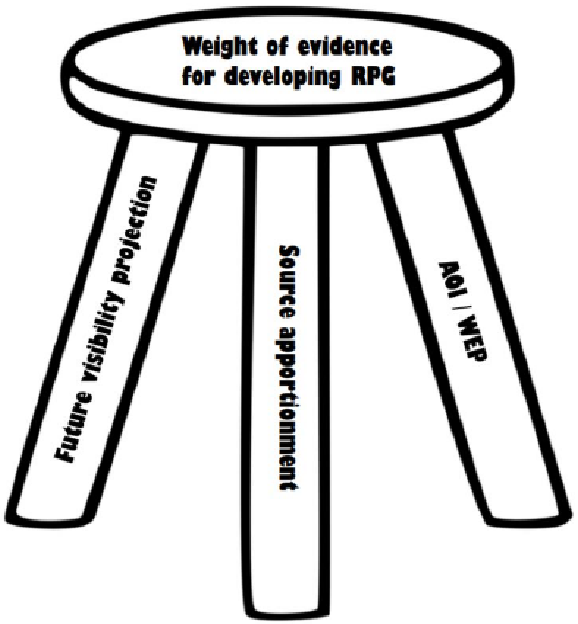
- Two-stroke lean burn engines
  - Low emissions combustion, including the Cooper Bessemer Clean Burn Technology™
  - Selective catalytic reduction
  - Replace internal combustion engines with electric utility powered compressors
  - Reduce capacity and/or operating hours

Four-Factor Analysis Progress

- Spring 2019:
  - Q/d to identify facilities subject to four-factor analysis
  - Consultation with EPA & federal land managers
- Summer 2019:
  - Request four-factor analyses from facilities
- Fall 2019:
  - Facilities submit four-factor analyses
  - Initial NMED/EHD review and requests for additional information
- Spring 2020:
  - NMED/EHD continue analysis
- Summer 2020
  - Begin determination of cost effective controls

Regional Modeling

- WRAP is developing modeling to supply information on weight of evidence for sources of impairment for each Class I area.
- Weight of evidence helps develop Reasonable Progress Goals using:
  - Future visibility projections
  - Source apportionment
  - Weighted emissions potential



WRAP Modeling for Regional Haze

https://www.wrapair2.org/rtowg.aspx

Western Regional Air Partnership

Regional Technical Operations Work Group

Regional Technical Operations Work Group

Overview

- Regional analyses in support of planning activities related to emissions and modeling for regional haze, ozone, PM, and other indicators.
- Evaluation of background and regional transport, international transport, sensitivity and other analyses of emissions data focused on the western U.S.
- Perform and leverage modeling, data analysis, and contribution assessment studies.
- Investigation of "background ozone" impacts to western U.S. locations.
- Coordination and collaboration with other WRAP member-sponsored regional air quality modeling groups including IWDW, NW-AIRQUEST, EPA-OAQPS, BAAQMD, and otherstate and local agencies performing regional ozone modeling.
- Provide guidance on more complete and uniform model performance evaluations (MPEs).
- Develop and implement a protocol to use the IWDW-WAQS capabilities as the WRAP Regional Technical Center.

Guidance Documents (final and draft as noted)

Procedures for Making 2028 Visibility Projections using the WRAP-WAQS 2014 Modeling Platform (July 24, 2020 draft)

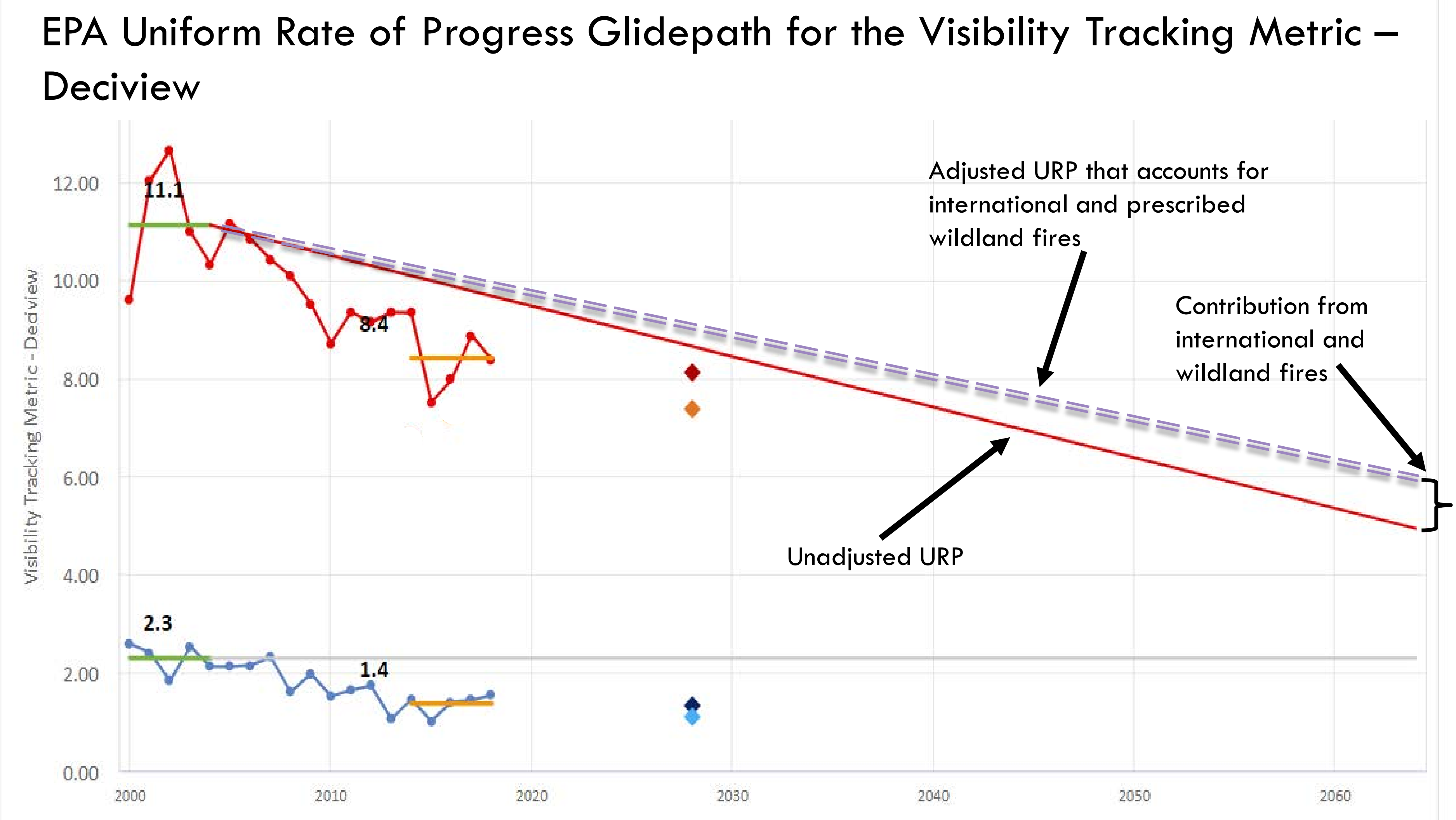
Adjusting the URP Glidepath Accounting for International Anthropogenic Emissions and Prescribed Fires using the WRAP 2014/2028 Modeling Platform Results (July 24, 2020 draft)

June 2020 Regional Haze Modeling Plan Schedule update (**PDF**) (final)

March 2020 Regional Haze Modeling Plan update (**PDF**) (final)

January 2020 Regional Haze Modeling Plan update (**PDF**) (final)

Modeling Products



Potential Additional Controls Modeling

- Potential Additional Control (PAC) run for 2028 visibility projections.
  - Submittal to WRAP due September 10th
- Part of weight of evidence for determining reasonable controls and progress goals.

Continuing EPA Steps 4 & 5

- Discuss controls analysis with companies
- Finalize technical feasibility and evaluate the four factors
- Finish the process of identifying cost effective control measures
- Determine emissions reductions that result from preliminary cost effective controls
- Model visibility impacts from potential additional controls
- Stakeholder outreach

ONE ALBUQUERQUE environmental health

EPA Steps 6 & 7

- Develop Reasonable Progress Goals (RPGs) based on WRAP three pillars for weight of evidence
- Compare RPGs to visibility "glidepath"
- Analysis of past and current visibility at New Mexico Class I Areas
- Consultation with other states, tribes, and Federal Land Managers on interstate emissions impacts
- Timeline is available on NMED website: https://www.env.nm.gov/air-quality/reg-haze/

Next Steps in Stakeholder Process

- Additional Outreach Webinar

- NMED and EHD plan to release draft State Implementation Plan (SIP) in early 2021.

- NMED/EHD NM Regional Haze webpage and listserv
  - https://www.env.nm.gov/air-quality/reg-haze/

- Please contact NMED/EHD with input
  - nm.regionalhaze@state.nm.us or
  - Mark Jones mark.jones@state.nm.us (505) 566-9746
  - Ed Merta emerta@cabq.gov (505) 768-2660

ONE ALBUQUERQUE environmental health

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

JAN 31 2007

EXHIBIT 5

Ms. Sheila Holman
Division of Air Quality
North Carolina Department of Environment
and Natural Resources
1641 Mail Service Center
Raleigh, NC 27699-1641

Dear Ms. Holman:

Thank you for the opportunity to review the proposed Best Available Retrofit Technology (BART) technology evaluation for the Blue Ridge Paper – Canton Mill (Blue Ridge) dated November 16, 2006. With the significant visibility impacts modeled for this facility, we believe that it is important that thorough consideration be given to all the various options for installing available retrofit control technologies at this facility.

Enclosed are our comments on the Blue Ridge document. Enclosure 1 describes our comments on the control and cost analyses. Enclosure 2 details our comments on the modeling analysis. Enclosure 3 provides some clarifications to certain statements addressed in the Blue Ridge document.

We appreciate your transmittal of this package for our consideration. If you have any further questions regarding this letter, please contact Michele Notarianni of the Region 4 staff at (404) 562-9031.

Sincerely,

Brenda C Johnson for

Kay T. Prince
Chief
Air Planning Branch

Enclosures

Enclosure 1: Control and Cost Analyses

1. Pollution Prevention (P2) Options:
    - When identifying all available retrofit control technologies, the "Guidelines for BART Determinations Under the Regional Haze Rule" (BART Guidelines) clarify that consideration should be given not only to add-on controls but also improvement in the performance of existing controls and P2. The analysis does not discuss the facility's evaluation of any P2 options for the five BART-eligible units, with the exception of installation of quaternary air on each recovery furnace (RF).

2. Process Changes to Reduce Formation of Emissions from RFs:
    - Although Table 4-1 indicates that several kraft pulp and paper mills utilize good combustion control practices to minimize sulfur dioxide (SO2) emissions from their RFs, there is no discussion of what options may exist for making process changes, such as improved furnace design and operation, to limit the formation of SO2 in each RF. An effective approach to minimizing the formation of SO2 in the RFs would be to practice high dry solids firing combined with a modern air system to promote efficient mixing. Examples of process changes which have been demonstrated are identified in section 5.3.1 of "Assessment of Control Options for BART Eligible Sources," prepared by NESCAUM, for the Mid-Atlantic/Northeast Visibility Union Regional Planning Organization: http://www.nescaum.org/documents/bart-resource-guide/. These examples include optimizing liquor and combustion air properties and firing patterns to maintain uniform temperatures in the lower part of the RF in order to reduce SO2 emissions, and reducing liquor sulfidity to reduce SO2 emissions from the RFs.

3. Control Option Alternatives:
    - The document states that installation of add-on SO2 controls on the RFs results in lower stack heights and a higher modeled delta deciview (dv) than current conditions due to decreased dispersion associated with scrubber exhaust characteristics. (Executive Summary) We believe this may be due to the effects of cooling the exhaust stream. The analysis does not discuss whether good engineering practice (GEP) was considered in the development of the new stack height for this SO2 control.

4. Lost Production Costs:
    - There is no indication of whether the facility considered ways to mitigate costs attributed to "Lost Production" listed in Table 4-2 (pulp purchase of $5,390,000 plus $975,843 for lost power generation per RF) and Table 4-4 ($11,550,000 for pulp purchase for 30 days downtime per RF). For example, the effects on costs in Tables 4-2 and 4-4 if potential controls were installed during an already planned plant shutdown for maintenance, or when one of the RFs is off-line, should be addressed. Also, it is unclear why one month is

needed for each RF retrofit to install a quaternary air system, which results in significant lost production costs of purchased pulp in Table 4-4.

- When major work is done at a pulp and paper mill, the mill can often increase production significantly prior to and following the shut down to offset any lost production. It is not clear whether the facility considered this possibility and its effects on the lost production costs.

- To minimize lost power generation costs listed in Table 4-2, it is not clear whether the facility considered achieving some additional power generation from its power boilers during the retrofit period to offset the losses. The mill has five power boilers and generally a pulp and paper mill with multiple power boilers does not operate all the boilers at maximum capacity at the same time.

5. <u>Contingency Costs in Table 4-2</u>:
   - In Table 4-2, the contingency factor of 15 percent should be justified. It is our understanding that a factor no higher than 10 percent would be considered acceptable for wet scrubber installation on a RF at a pulp and paper mill, and would be consistent with standard industry practice. Also, since this is a "turnkey" installation, it is unclear why such a high contingency factor is projected. Since no distinct retrofit factor is identified, it is possible that the facility may have merged the retrofit factor with the contingency factor, resulting in the 15 percent contingency factor used in Table 4-2. The *EPA Air Pollution Control Cost Manual* (Cost Manual), EPA/452/B-02-001, January 2002, distinguishes between the contingency and retrofit factors and recommends keeping them separate as follows. A retrofit factor should be reserved for those items directly related to the demolition, fabrication, and installation of the control system, and should not be double-counted again as part of a contingency factor. In this case, the additional ductwork, new stack, fan, and switch gear should be assigned to the retrofit factor since they are a necessary part of installing this control on an existing unit. A contingency factor should be applied to only those items that could incur a reasonable but unanticipated cost increase (i.e., outside of the contractor's control), and are not directly related to the retrofit factor elements just described. (See pages 2-28 to 2-30 in subsection 2.5.4.2 of Chapter 2, "Cost Estimation: Concepts and Methodology," (dated January 2002) in Section 1 of the Cost Manual.)

   - The contingency factor calculations in Table 4-2 are not based on the correct line item costs and need to be redone. The factor was applied to the scrubber "installation cost," additional ductwork, new stack, fan, and switch gear, and lost power generation. This is incorrect for two reasons. First, the "installation cost" listed for the wet scrubber appears to also include the cost of the equipment. The contingency factor should be applied to the purchased equipment costs. However, installation costs are not to be included in contingency factor calculations. This should be corrected. The second reason the calculations are incorrectly applied is that the "14 days lost power generation" cost of $975,843 should not be included in the "contingency" cost calculations. The Cost Manual describes contingencies as a category that covers unforeseen costs that may arise, such as delays encountered in start-up and increases in field labor costs. (See page 2-5, of Chapter 2, "Cost Estimation: Concepts and Methodology," (dated January 2002) in Section 1 of the Cost Manual.) The lost power generation cost in Table 4-2 refers to power that cannot be produced during the 14-day retrofit period for each RF, which is a planned event, not an unforeseen cost. We note that lost production in terms of pulp purchase correctly does not appear to be included in the contingency cost calculations.

6. RF Wet Scrubber Cost Considerations:
   - Table 4-2 describes costs with wet scrubber installation on one of the RFs. Given the relatively high nature of costs for the modifications to existing ductwork and installation of a new stack, fan, and switch gear (totaling to $11,945,605), consideration should be given to other, more cost effective options. For example, the feasibility and cost effectiveness of moving the road or other buildings to allow closer location of the wet scrubbers and avoid extensive ductwork could be considered.

   - It would be helpful to have more information on the design of the wet scrubber analyzed. We are aware of at least one kraft pulp mill (i.e., the James River Camas Mill in Washington State) that has installed a cross-flow, packed bed scrubber following the RF electrostatic precipitator (ESP) as part of an energy recovery system. At that mill, caustic (sodium hydroxide or NaOH) is added to the scrubber liquid and the mill has claimed SO2 reductions as a result. It is not clear whether the facility has considered installing a similar system.

   - There is no discussion indicating whether the facility considered use of caustic as the scrubbing reagent instead of limestone. Kraft pulp mills have a relatively inexpensive supply of caustic available since it is used in the cooking liquor, which can make caustic more economical than limestone. Also, the use of caustic eliminates the material handling and space requirements associated with lime or limestone systems. Lime and limestone processes produce a sludge which requires dewatering and landfilling. Wet caustic processes produce a neutral pH solution which can be pumped to the existing mill wastewater treatment system for disposal. Thus, the estimated annual costs would be greatly reduced by using a caustic scrubber instead.

   - We suggest that the State closely evaluate the electricity costs for the RF scrubber. For example, the basis for the 746 kilowatt-hours used in Table 4-2 should be discussed. Other considerations should include the assumed pressure drop of the scrubber, and what portion of the electricity costs are associated with the use of limestone rather than caustic (e.g., limestone preparation and slurry mix system, gypsum filter system, etc.).

7. RF Quaternary Air System Cost Considerations:
   - The capital cost estimate of $9 million (includes quaternary air and new liquor guns for both RFs) cited on page 4-7 and detailed per RF in Table 4-4 seems extremely high. In 2001, the American Forest and Paper Association (AF&PA) commissioned BE&K Engineering to develop emissions control cost estimates for a variety of scenarios at pulp and paper mills, including the addition of a quaternary air system for reducing NO_X emissions from a RF. The model RF was larger than the RFs at Blue Ridge. Based on the AF&PA analysis, the capital cost for the quaternary air system was $624,000 per furnace. Disregarding differences in size and base years, the total cost would be approximately $1.2 million for two RFs, which is considerably less than the $9 million quoted on page 4-7. It would be helpful if Blue Ridge could provide an estimate just for the addition of the quaternary air system, omitting the costs of the new liquor guns, to provide for a better comparison of costs.

8. Supporting Documentation for Cost Analyses:
   - To aid review of the document, we suggest that the vendor quotes, data estimates, and relevant portions of the presentation identified in the cost references [1], [6], [7] in Tables 4-2 be included in this document. Also, it is unclear where the e-mail described in Reference 1 of Table 4-2 is located in the documentation so we were unable to review this reference.

   - Reference 7 of Table 4-2 indicates that costs for wet scrubber installation are based on a vendor quote for an "original recovery furnace," which does not appear to be either of the RFs subject to this BART analysis. Although the facility adapted the cost estimate to the size of the No. 10 RF, we question why the facility did not seek a vendor quote for wet scrubber installation specific to the RFs subject to this BART analysis (i.e., No. 10 and No. 11). We recommend that a copy of the quote be included in the documentation to provide information such as what year the quote for the original RF was received.

   - Reference 7 of Table 4-2 also states that, "Cost was escalated using EPA's 0.6 rule…" The "0.6 rule" referenced is to be used for a rough estimate calculation of costs only and should not be relied upon for this BART analysis to estimate installation costs of the wet scrubber. Also, we are not aware that the "0.6 rule" is part of an EPA document. However, the book, *Plant Design and Economics for Chemical Engineers* by Peter and Timmerhaus (Fifth Edition) does discuss this "rule of thumb" and calls it the "six-tenths-factor" rule. (Peters, Max S., Timmerhaus, Klaus and West, Ronald. *Plant Design and Economics for Chemical Engineers*, Fifth Edition, McGraw-Hill, 2002, p. 169.)

9. Capital Recovery Factor (CRF) Calculations:
   - The facility should justify its capital recovery cost assumptions of an equipment life of 10 years with an interest rate of 15 percent listed under "Indirect Annual Costs" in Tables 4-2, 4-4, and 4-6. For capital recovery costs on wet scrubbers for acid gas, the EPA Cost Manual and EPA's *Technical Support Document: Chemical Recovery Combustion Sources at Kraft and Soda Pulp Mills* (EPA-453/R-96-012, October 1996) presume a CRF based on a 15-year control equipment life and an interest rate of seven percent. Note that changing the assumptions about equipment life and interest rates to this presumptive value significantly decreases the annualized cost estimates.

Enclosure 2: Modeling Analysis

1. Table 5-1 indicates a 31.25-meter decrease in the stack heights for the No. 10 and 11 RFs' stack for Scenarios 2 and 5. It is unclear why a decrease in stack height is required or if this is a typographical error. Also, the analysis does not discuss whether GEP was considered in the development of the new stack height for this SO2 control. According to Table 5-1, the modeled location of the stacks has not changed from the current location. Table 5-4 indicates that the maximum visibility impact has shifted slightly to another geographical location in the Shining Rock and Great Smoky Mountain Class I areas. With decreased SO2 emissions from installation of the scrubber, the expected result is that the visibility impact should also decrease. The analysis should provide more discussion on how and where the visibility increases occurred in the Class I areas in addition to providing the maximum delta visibility impact and explain why a decrease in stack heights is necessary.

2. The NOx emissions used in the baseline (i.e., Scenario 1) modeling was based on a February 1999 stack test. There is no discussion of why data from this year was used to the exclusion of data from other years. Such discussion should include such items as stack test data availability from other years and how this ensures that the maximum 24-hr emission rate for the 2001-2003 period was developed. We encourage the State to review these data to ensure the assumptions supporting the emission rates are correct and the supporting documentation is submitted.

3. A vendor guarantee was used to set the emission rate for the black liquor oxidation system (BLOX) regenerative thermal oxidizer (RTO) provided in Table 5-2 (reference 3). We suggest that the referenced guarantee be included in the document and recommend that the State carefully evaluate this rate in conjunction with the specified operating parameters to ensure appropriate values are being used in the BART modeling.

4. It may appear that the visibility improvements from the various control scenarios assessed do not indicate a desired level of benefit at two of the five Class I areas, but the other three Class I areas being affected by the facility could also be considered in the determination.

5. Addition of a wet scrubber should also reduce fine particulate matter (PM2.5), including condensable PM, which is not controlled by the ESP. The impact of additional PM control achieved by the scrubber (for scenario 2) should be considered. The modeling results presented indicate fine PM has a limited impact on the modeled extinction (i.e., 9.51 percent and 18.6 percent of the modeled extinction for the baseline and Scenario 2 conditions, respectively, for Shining Rock). Also, the PM emissions are based on the most recent compliance test. These data likely represent the best ESP operating conditions, which may not be representative of ongoing emissions.

6. The State might consider giving a second look at the model inputs for PM emissions and the resulting visibility impacts for baseline conditions and scenarios No 2 and No 5 for two reasons. One reason to reconsider the PM inputs into the modeling is that the PM emissions are based on the most recent compliance test (as noted above in item number 5). These data likely represent the best ESP operating conditions, which may not be representative of ongoing emissions.

   Another reason to possibly reconsider the PM data and modeled impacts is that there are ongoing discussions taking place between EPA and the pulp and paper industry (AF&PA/NCASI) related to measurement of PM2.5 emissions. The current use of EPA Method 202 by the industry appears to be underreporting PM2.5 emissions, specifically condensable PM2.5. In some cases, the condensable PM is analyzed to determine the elemental composition and it is assumed that all of the sulfates found in the condensable PM are "artifacts" resulting from conversion of SO2 to sulfates (i.e., to SO3 and then to H2SO4). The reported condensable PM is "corrected" by subtracting the sulfate fraction from the total condensable PM emissions. This "correction" results in biasing the measured emissions low. It is not clear whether this type correction was done for the reported emissions used in this modeling analysis. The State may want to clarify how EPA Method 202 was used in the measurement of PM2.5 emissions. For more information on this method, go to: http://www.epa.gov/ttn/emc/methods/method202.html .)

7. **Modeling performed at 1-km grid resolution** - Page 2-4 of the November 16, 2006 submission to NC DAQ notes that comments received from NC DAQ on March 7, 2006, related to the modeling protocol specific to the Blue Ridge Canton Mill states that "the 12-km screening approach should not be used. At a minimum, the 4-km CALMET data should be used and a refinement to 1-km may be necessary." This comment matches page 48 of the VISTAS Protocol document*, which says that source-receptor distances less than about 50 km may require grid resolution less than 1-km if complex terrain effects are likely to be important. More refined digital elevation model (DEM) data are also required. Complex terrain effects should be important in western North Carolina both within the Class 1 areas of concern and between the source and each of these areas. Although the BART control technology report omits the 12-km screening, it appears to report on only a 4-km grid resolution instead of the finer resolution recommended. It is not clear whether consideration was given to revising the modeling using a 1-km CALMET grid.

8. **Results tables specified in the VISTAS Protocol** - The VISTAS Protocol provides standard table formats for presenting modeling results. There should be a table showing number of days and number of receptors with impact greater than

---

* Visibility Improvement State and Tribal Association of the Southeast (VISTAS), Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART), December 22, 2005 (Revision 3.2 – 8/31/06).

0.5 dv for each Class 1 area, and for each year, number of days and number of receptors with impact greater than 1.0 dv for each Class 1 area for the entire 3-yr period, and the maximum 24-hr impact during the 3-yr period. These tables were provided in the October 2006 BART Exemption Modeling Report, but have not been included in the November 16, 2006, document. It is suggested that similar tables be included in the determination report. Also, documentation that addresses the development of the baseline modeling should be included in the determination report. This may be in the BART exemption modeling report. It is suggested that the complete October 2006 BART Exemption Modeling Report be included as an appendix to the determination report.

9. **Deciview Thresholds** - The document states in several places that "...the change in modeled visibility impact...is less than the 1 deciview threshold of human perception for changes in visibility." This statement implies that the controls are not considered to make enough of an improvement in visibility at the Class I areas identified in the report. We note, however, that there is no bright line for evaluating in the BART determination analysis the degree of visibility improvement that is considered significant enough to warrant BART controls. Rather, a State has flexibility in setting absolute thresholds and determining the weight and significance to be assigned to each BART factor. (See 70 FR 39170, 1st col., July 6, 2005.) Also, this statement does not recognize that a source may be *contributing* to visibility impairment at a Class I area.

Enclosure 3: Text Clarifications

Below are clarifications we wish to note on certain statements in the text. (The location of the text in the document is identified in parentheses.)

1. BACT Cost Effectiveness Comparisons (Section 1.2, P.1-1; cover letter, P.1) The document makes the following statement: "As a comparison, costs from \$3,000 to \$5,000 per ton of emissions reduction are generally considered cost prohibitive for BACT evaluations." The Agency has not established cost effectiveness values considered cost prohibitive in regulation or policy. Also, these BACT cost effectiveness numbers may not be directly applicable for use in the BART cost analysis as BACT costs can apply to a new source adding on controls, whereas BART costs for retrofit technology may need to be weighed differently. The State will identify what costs are reasonable or not. Where data are available, we recommend use of a comparative approach for costs, i.e., compare cost effectiveness numbers to a similar facility which operates with controls under similar conditions. Another way of stating this is as follows.

   If comparable emissions units are operating with controls, the owner of the BART-affected unit should show why control costs are prohibitive for the BART-affected unit, even though they are acceptable for similar controlled units in operation.

2. BART-Eligibility Descriptions (Section 2.2, P.2-2; Section 3.1, P. 3.1) *Potential to Emit (PTE) Thresholds:* The PTE threshold provided for BART – eligible sources should be corrected to read, "...the potential to emit ~~more than~~ 250 tons per year or more..." (See 40 CFR 51.301, "Definitions," *Existing stationary facility.*)

3. Due date for Regional Haze SIPs (Section 2.2, P. 2-3) The document identifies a due date for Regional Haze SIPs of January 2008. To clarify, the due date for Regional Haze SIPs specified in the Regional Haze regulations at 40 CFR 51.308 (b) is: "...no later than December 17, 2007."

4. Line-of-Sight (LOS)
   (a) The document refers to a proposed LOS approach in several places and presents data for comparison on page 2-5. We recommend excluding LOS documentation since, as the report indicates, this specific approach is not appropriate for BART modeling purposes.

   (b) The document provides selected definitions from 40 CFR 51. We wish to clarify that the definitions provided in Section 2.1 for *Line-of-Sight (LOS)* and *Just Noticeable Change* are not from the Definitions section of the Regional Haze regulations (40 CFR 51.301, "Definitions").

5. Permit Changes (Section 4.2, P.4-4)

The document asserts that the electrostatic precipitators (ESPs) on each RF exceed the Maximum Achievable Control Technology (MACT) standard for particulate matter (PM), and that this level of control is already required in the facility's Title V operating permit. The BART Guidelines say if the most stringent control available is adopted, it must be made federally enforceable for purposes of BART. Thus, the SIP and potentially the facility's permit must be modified to include a statement that these controls and operating conditions on the two recovery furnaces also serve to satisfy BART for PM.

6. References (Tables 4-2, 4-4, 4-6)
The EPA Cost Manual references for Tables 4-2, 4-4, and 4-6 are confusing as written, which made it difficult to find the appropriate citations. Chapter 1, December 1995, is cited in the EPA Cost Manual in these cost references. Since there are presently nine chapters labeled "Chapter 1" in the Cost Manual dated January 2002, we suggest that these references be clarified to include the relevant section and chapter title. This will enable reviewers to find the referenced portions of the document. In this case, the relevant items we suggest to include in these Cost Manual references are italicized as follows: "*EPA Air Pollution* Control Cost Control Manual, sixth edition *(January 2002)*, EPA 452-02-001, *Section 5.2*, Chapter 1, "*Wet Scrubbers for Acid Gas,*" December 1995." (The current EPA Cost Manual is available at: http://www.epa.gov/ttncatc1/products.html#cccinfo.)

7. Table 4-1 – "Summary of RBLC Database for SO2 Control Technologies"
It appears that the following four "RACT/BACT/LAER (RBLC)" Clearinghouse entries of facilities with SO2 controls on their RFs were either inadvertently omitted from Table 4-1 or slightly different search criteria may have been used. We used the following search criteria: default time span of 10 years back, Process Type: 30.211 "Kraft Recovery Furnaces/Boilers," Pollutant: "SOx". For completeness, we suggest including these entries if they were omitted in error. The following control descriptions are included here for your convenience:

- LA-0201, Weyerhaeuser Company, Red River Mill facility (Proper Boiler Design and Operation);
- LA-0207, International Paper Co, Mansfield Mill (Proper Design, Good Combustion Practices, Firing Low Sulfur Fuel, and a 10% Annual Capacity Factor for Fossil Fuels);
- MS-0078, Georgia Pacific Corporation, Monticello Mill (Combustion Control and Furnace Design); and
- NC-0108, International Paper, Roanoke Rapids Mill (Furnace Design and Combustion optimization).

Based on the RBLC search we performed, it also appears that certain RBLC entries with a "No Controls Feasible" label are not included in Table 4-1. We are unclear as to the reason for this. For completeness, we suggest that the table could either include all or exclude all facilities with a "No Controls Feasible" label.

8. Visibility Impact Thresholds (Section 4.1.5, P. 4-3)
Section 4.1.5 provides a summary of Step 5 of the BART Guidelines. The second paragraph of this section states: "If the net visibility improvement is less than the humanly perceptible change, then there is no need for the facility to implement the control technologies because the resulting visibility impacts would be negligible." The BART Guidelines do not make such an assertion. Rather, the Guidelines provide flexibility to the States with setting thresholds and weighing each of the BART factors. (See 70 FR 39170, 1st col., July 6, 2005.) All of the statutory factors should be used in the determination of whether or not BART controls are needed. Visibility improvement based on modeling results is only one of the factors that should be assessed in this decision.

9. 22nd highest values for the two worst-case years (Section 5.8, P. 5-7)
Page 5-7 of the document states that a spreadsheet was used to determine the 22nd highest values for the two worst-case years. The 98th percentile value for an individual year is the 8th highest value, so it is unclear why the report references the 22nd highest value. This appears to be a typographical error.

EXHIBIT 6

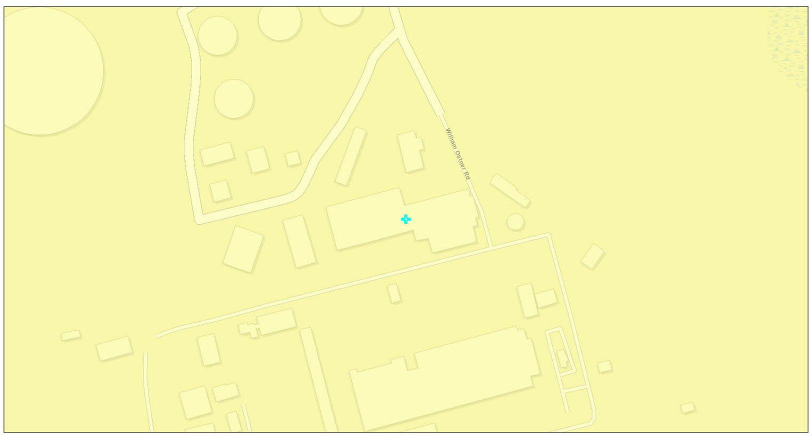
EJScreen Community Report

This report provides environmental and socioeconomic information for user-defined areas, and combines that data into environmental justice and supplemental indexes.

Jacksonville, FL

20 miles Ring Centered at 30.418484,-81.552898
Population: 1,044,071
Area in square miles: 1256.38

A3 Landscape



February 15, 2024
JEA Northside
1:2,257
0 0.02 0.04 0.09 mi
0 0.04 0.07 0.15 km

Esri Community Maps Contributors, City of Jacksonville, FDEP, © OpenStreetMap, Microsoft, Esri, TomTom, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Census Bureau, USDA, USFWS

COMMUNITY INFORMATION

Low income: 33 percent
People of color: 46 percent
Less than high school education: 9 percent
Limited English households: 3 percent
Unemployment: 5 percent
Persons with disabilities: 14 percent
Male: 49 percent
Female: 51 percent
73 years Average life expectancy
$36,305 Per capita income
Number of households: 413,134
Owner occupied: 59 percent

BREAKDOWN BY RACE

White: 54%
Black: 27%
American Indian: 0%
Asian: 4%
Hawaiian/Pacific Islander: 0%
Other race: 1%
Two or more races: 4%
Hispanic: 10%

BREAKDOWN BY AGE

From Ages 1 to 4	6%
From Ages 1 to 18	22%
From Ages 18 and up	78%
From Ages 65 and up	15%

LIMITED ENGLISH SPEAKING BREAKDOWN

Speak Spanish	50%
Speak Other Indo-European Languages	21%
Speak Asian-Pacific Island Languages	20%
Speak Other Languages	10%

Notes: Numbers may not sum to totals due to rounding. Hispanic population can be of any race. Source: U.S. Census Bureau, American Community Survey (ACS) 2017 -2021. Life expectancy data comes from the Centers for Disease Control.

LANGUAGES SPOKEN AT HOME

LANGUAGE	PERCENT
English	86%
Spanish	7%
French, Haitian, or Cajun	1%
Russian, Polish, or Other Slavic	1%
Other Indo-European	2%
Tagalog (including Filipino)	1%
Other Asian and Pacific Island	1%
Arabic	1%
Total Non-English	14%

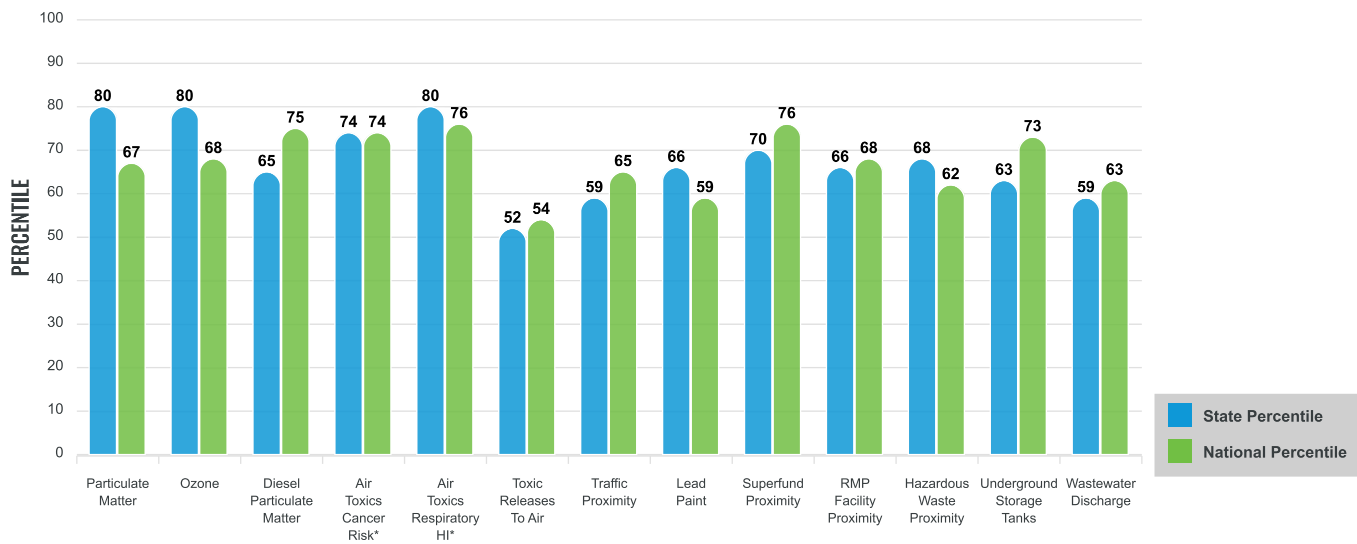
Environmental Justice & Supplemental Indexes

The environmental justice and supplemental indexes are a combination of environmental and socioeconomic information. There are thirteen EJ indexes and supplemental indexes in EJScreen reflecting the 13 environmental indicators. The indexes for a selected area are compared to those for all other locations in the state or nation. For more information and calculation details on the EJ and supplemental indexes, please visit the EJScreen website.

EJ INDEXES

The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.

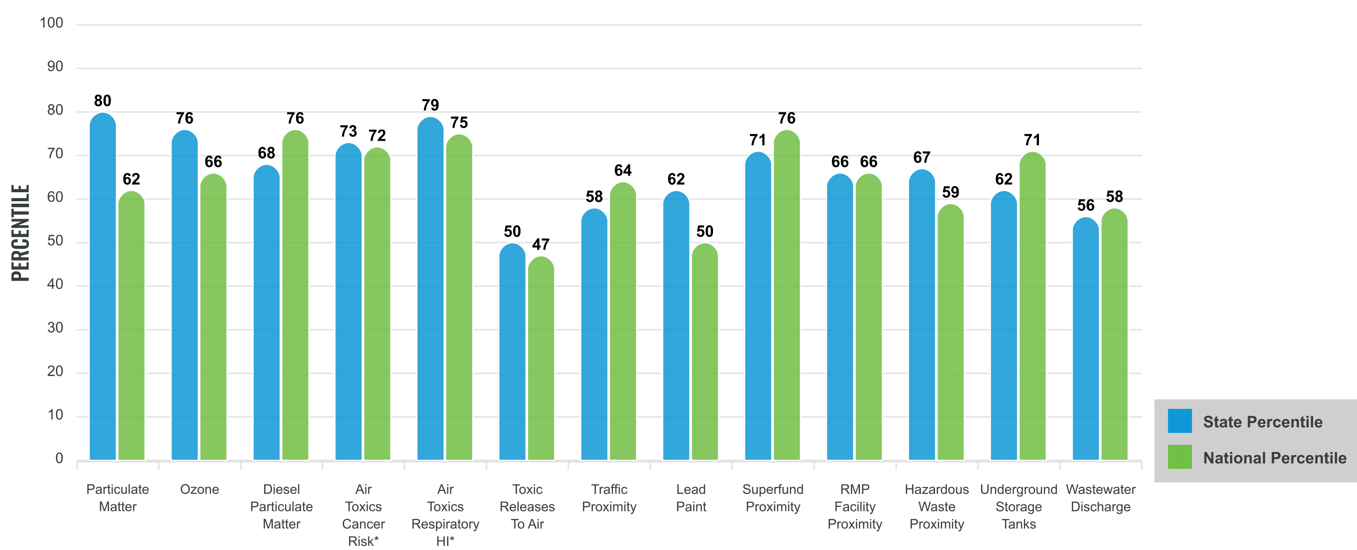
EJ INDEXES FOR THE SELECTED LOCATION



SUPPLEMENTAL INDEXES

The supplemental indexes offer a different perspective on community-level vulnerability. They combine data on percent low-income, percent linguistically isolated, percent less than high school education, percent unemployed, and low life expectancy with a single environmental indicator.

SUPPLEMENTAL INDEXES FOR THE SELECTED LOCATION



These percentiles provide perspective on how the selected block group or buffer area compares to the entire state or nation.

Report for 20 miles Ring Centered at 30.418484,-81.552898

EJScreen Environmental and Socioeconomic Indicators Data

SELECTED VARIABLES	VALUE	STATE AVERAGE	PERCENTILE IN STATE	USA AVERAGE	PERCENTILE IN USA
POLLUTION AND SOURCES					
Particulate Matter ($\mu g/m^3$)	8.2	7.52	87	8.08	50
Ozone (ppb)	61.5	59.4	71	61.6	53
Diesel Particulate Matter ($\mu g/m^3$)	0.323	0.293	63	0.261	73
Air Toxics Cancer Risk* (lifetime risk per million)	28	25	1	25	5
Air Toxics Respiratory HI*	0.35	0.32	11	0.31	31
Toxic Releases to Air	260	1,900	42	4,600	36
Traffic Proximity (daily traffic count/distance to road)	130	160	63	210	64
Lead Paint (% Pre-1960 Housing)	0.19	0.14	75	0.3	47
Superfund Proximity (site count/km distance)	0.13	0.13	73	0.13	75
RMP Facility Proximity (facility count/km distance)	0.71	0.31	89	0.43	82
Hazardous Waste Proximity (facility count/km distance)	0.6	0.52	78	1.9	52
Underground Storage Tanks (count/km^2)	6.5	7	67	3.9	82
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.78	0.52	92	22	90
SOCIOECONOMIC INDICATORS					
Demographic Index	40%	39%	56	35%	64
Supplemental Demographic Index	15%	15%	54	14%	59
People of Color	46%	45%	56	39%	63
Low Income	33%	33%	55	31%	60
Unemployment Rate	5%	5%	61	6%	59
Limited English Speaking Households	3%	7%	57	5%	69
Less Than High School Education	9%	11%	55	12%	55
Under Age 5	6%	5%	70	6%	64
Over Age 64	15%	23%	41	17%	49
Low Life Expectancy	21%	19%	64	20%	64

*Diesel particulate matter, air toxics cancer risk, and air toxics respiratory hazard index are from the EPA's Air Toxics Data Update, which is the Agency's ongoing, comprehensive evaluation of air toxics in the United States. This effort aims to prioritize air toxics, emission sources, and locations of interest for further study. It is important to remember that the air toxics data presented here provide broad estimates of health risks over geographic areas of the country, not definitive risks to specific individuals or locations. Cancer risks and hazard indices from the Air Toxics Data Update are reported to one significant figure and any additional significant figures here are due to rounding. More information on the Air Toxics Data Update can be found at: https://www.epa.gov/haps/air-toxics-data-update.

Sites reporting to EPA within defined area:

Superfund 3
Hazardous Waste, Treatment, Storage, and Disposal Facilities 35
Water Dischargers 4582
Air Pollution 402
Brownfields 152
Toxic Release Inventory 146

Other community features within defined area:

Schools 225
Hospitals 31
Places of Worship 908

Other environmental data:

Air Non-attainment .... Yes
Impaired Waters .... Yes

Selected location contains American Indian Reservation Lands* .... No
Selected location contains a "Justice40 (CEJST)" disadvantaged community .... Yes
Selected location contains an EPA IRA disadvantaged community .... Yes

Report for 20 miles Ring Centered at 30.418484,-81.552898

EJScreen Environmental and Socioeconomic Indicators Data

HEALTH INDICATORS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Low Life Expectancy	21%	19%	64	20%	64
Heart Disease	6	7.2	34	6.1	48
Asthma	9.5	8.7	75	10	36
Cancer	5.7	6.9	38	6.1	39
Persons with Disabilities	13.4%	13.9%	51	13.4%	56

CLIMATE INDICATORS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Flood Risk	11%	26%	44	12%	69
Wildfire Risk	40%	32%	65	14%	85

CRITICAL SERVICE GAPS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Broadband Internet	12%	13%	56	14%	54
Lack of Health Insurance	12%	13%	52	9%	75
Housing Burden	Yes	N/A	N/A	N/A	N/A
Transportation Access	Yes	N/A	N/A	N/A	N/A
Food Desert	Yes	N/A	N/A	N/A	N/A

Report for 20 miles Ring Centered at 30.418484,-81.552898

EXHIBIT 7

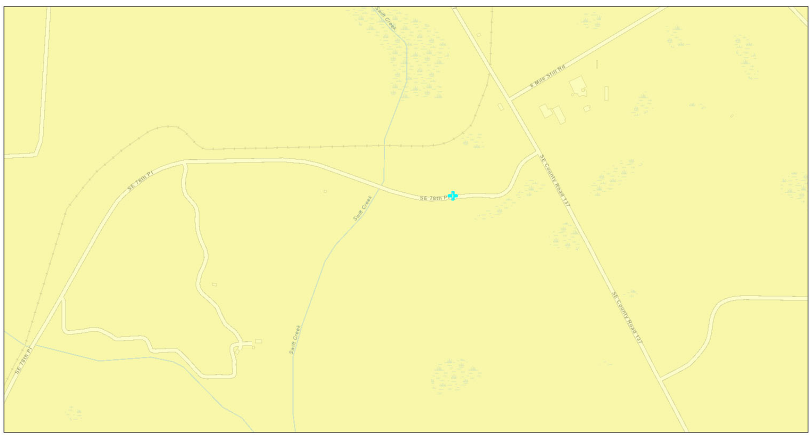
EJScreen Community Report

This report provides environmental and socioeconomic information for user-defined areas, and combines that data into environmental justice and supplemental indexes.

Hamilton County, FL

20 miles Ring Centered at 30.408172,-82.787390
Population: 69,475
Area in square miles: 1256.38

A3 Landscape



February 15, 2024

Nutrien White Springs

1:9,028

Esri Community Maps Contributors, FDEP, © OpenStreetMap, Microsoft, Esri, TomTom, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Census Bureau, USDA, USFWS

LANGUAGES SPOKEN AT HOME

LANGUAGE	PERCENT
English	92%
Spanish	6%
French, Haitian, or Cajun	1%
Total Non-English	8%

COMMUNITY INFORMATION

Low income: 44 percent

People of color: 36 percent

Less than high school education: 17 percent

Limited English households: 1 percent

Unemployment: 8 percent

Persons with disabilities: 19 percent

Male: 53 percent

Female: 47 percent

76 years
Average life expectancy

$23,343
Per capita income

Number of households: 24,448

Owner occupied: 66 percent

BREAKDOWN BY RACE

White: 64%

Black: 23%

American Indian: 0%

Asian: 1%

Hawaiian/Pacific Islander: 0%

Other race: 1%

Two or more races: 4%

Hispanic: 8%

BREAKDOWN BY AGE

From Ages 1 to 4	6%
From Ages 1 to 18	23%
From Ages 18 and up	77%
From Ages 65 and up	18%

LIMITED ENGLISH SPEAKING BREAKDOWN

Speak Spanish	82%
Speak Other Indo-European Languages	4%
Speak Asian-Pacific Island Languages	14%
Speak Other Languages	0%

Notes: Numbers may not sum to totals due to rounding. Hispanic population can be of any race.
Source: U.S. Census Bureau, American Community Survey (ACS) 2017 -2021. Life expectancy data comes from the Centers for Disease Control.

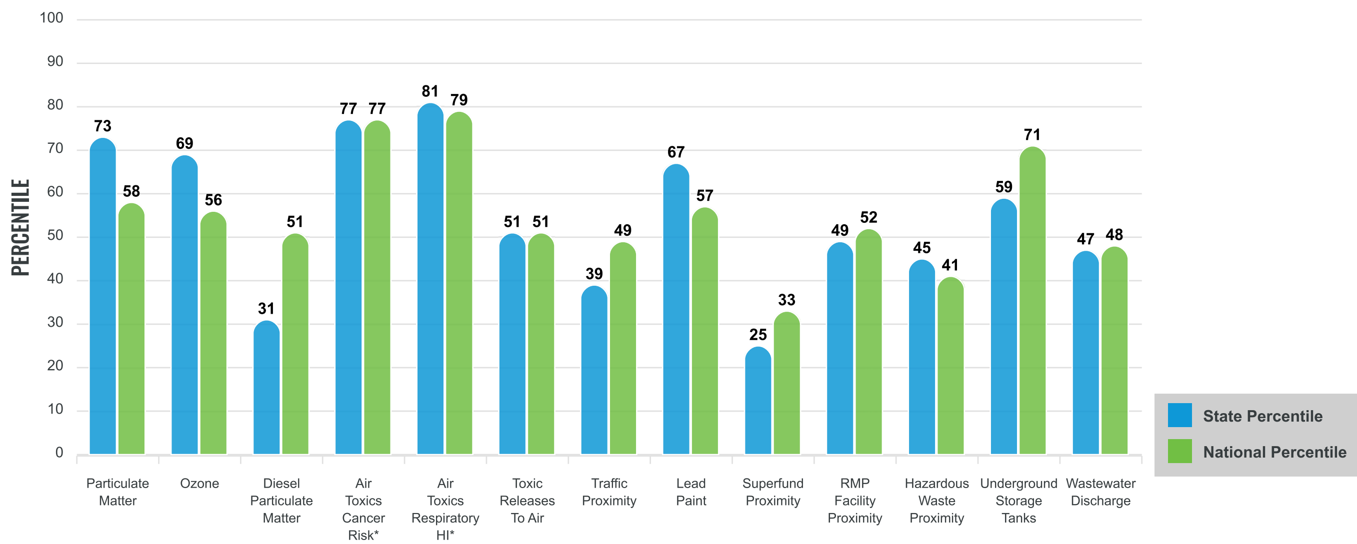
Environmental Justice & Supplemental Indexes

The environmental justice and supplemental indexes are a combination of environmental and socioeconomic information. There are thirteen EJ indexes and supplemental indexes in EJScreen reflecting the 13 environmental indicators. The indexes for a selected area are compared to those for all other locations in the state or nation. For more information and calculation details on the EJ and supplemental indexes, please visit the EJScreen website.

EJ INDEXES

The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.

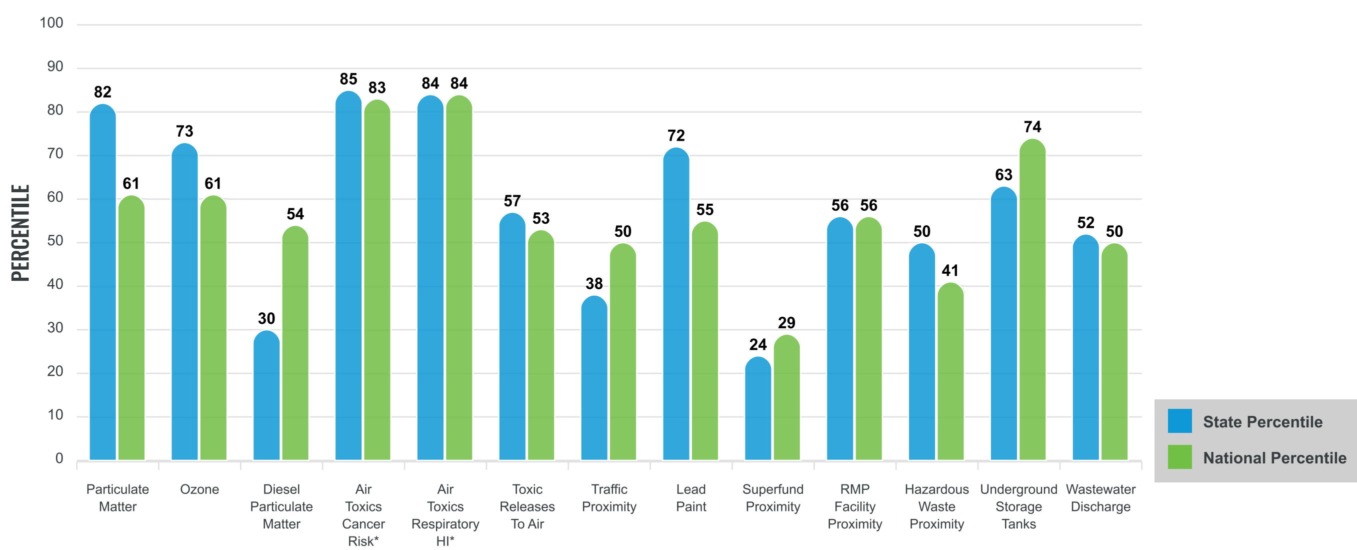
EJ INDEXES FOR THE SELECTED LOCATION



SUPPLEMENTAL INDEXES

The supplemental indexes offer a different perspective on community-level vulnerability. They combine data on percent low-income, percent linguistically isolated, percent less than high school education, percent unemployed, and low life expectancy with a single environmental indicator.

SUPPLEMENTAL INDEXES FOR THE SELECTED LOCATION



These percentiles provide perspective on how the selected block group or buffer area compares to the entire state or nation.

Report for 20 miles Ring Centered at 30.408172,-82.787390

EJScreen Environmental and Socioeconomic Indicators Data

SELECTED VARIABLES	VALUE	STATE AVERAGE	PERCENTILE IN STATE	USA AVERAGE	PERCENTILE IN USA
POLLUTION AND SOURCES					
Particulate Matter ($\mu g/m^3$)	7.73	7.52	71	8.08	38
Ozone (ppb)	59.6	59.4	51	61.6	36
Diesel Particulate Matter ($\mu g/m^3$)	0.152	0.293	16	0.261	32
Air Toxics Cancer Risk* (lifetime risk per million)	30	25	55	25	52
Air Toxics Respiratory HI*	0.36	0.32	11	0.31	31
Toxic Releases to Air	190	1,900	37	4,600	31
Traffic Proximity (daily traffic count/distance to road)	41	160	29	210	36
Lead Paint (% Pre-1960 Housing)	0.13	0.14	69	0.3	39
Superfund Proximity (site count/km distance)	0.019	0.13	14	0.13	16
RMP Facility Proximity (facility count/km distance)	0.14	0.31	49	0.43	42
Hazardous Waste Proximity (facility count/km distance)	0.17	0.52	47	1.9	32
Underground Storage Tanks (count/km^2)	4.8	7	60	3.9	76
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.0012	0.52	54	22	50
SOCIOECONOMIC INDICATORS					
Demographic Index	41%	39%	58	35%	65
Supplemental Demographic Index	19%	15%	73	14%	76
People of Color	34%	45%	45	39%	53
Low Income	46%	33%	74	31%	76
Unemployment Rate	8%	5%	77	6%	75
Limited English Speaking Households	1%	7%	44	5%	58
Less Than High School Education	16%	11%	75	12%	74
Under Age 5	6%	5%	66	6%	60
Over Age 64	18%	23%	51	17%	61
Low Life Expectancy	23%	19%	81	20%	80

*Diesel particulate matter, air toxics cancer risk, and air toxics respiratory hazard index are from the EPA's Air Toxics Data Update, which is the Agency's ongoing, comprehensive evaluation of air toxics in the United States. This effort aims to prioritize air toxics, emission sources, and locations of interest for further study. It is important to remember that the air toxics data presented here provide broad estimates of health risks over geographic areas of the country, not definitive risks to specific individuals or locations. Cancer risks and hazard indices from the Air Toxics Data Update are reported to one significant figure and any additional significant figures here are due to rounding. More information on the Air Toxics Data Update can be found at: https://www.epa.gov/haps/air-toxics-data-update.

Sites reporting to EPA within defined area:

Superfund 0
Hazardous Waste, Treatment, Storage, and Disposal Facilities 2
Water Dischargers ....
. 290
Air Pollution 37
Brownfields 15
Toxic Release Inventory 9

Other community features within defined area:

Schools 33
Hospitals 8
Places of Worship 171

Other environmental data:

Air Non-attainment .... No
Impaired Waters .... Yes

Selected location contains American Indian Reservation Lands* .... No
Selected location contains a "Justice40 (CEJST)" disadvantaged community .... Yes
Selected location contains an EPA IRA disadvantaged community .... Yes

Report for 20 miles Ring Centered at 30.408172,-82.787390

EJScreen Environmental and Socioeconomic Indicators Data

HEALTH INDICATORS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Low Life Expectancy	23%	19%	81	20%	80
Heart Disease	7.6	7.2	61	6.1	77
Asthma	9.6	8.7	77	10	40
Cancer	6.7	6.9	55	6.1	59
Persons with Disabilities	19.7%	13.9%	83	13.4%	85

CLIMATE INDICATORS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Flood Risk	10%	26%	41	12%	65
Wildfire Risk	13%	32%	59	14%	82

CRITICAL SERVICE GAPS

INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Broadband Internet	20%	13%	75	14%	74
Lack of Health Insurance	14%	13%	62	9%	81
Housing Burden	No	N/A	N/A	N/A	N/A
Transportation Access	Yes	N/A	N/A	N/A	N/A
Food Desert	Yes	N/A	N/A	N/A	N/A

Report for 20 miles Ring Centered at 30.408172,-82.787390