DRAFT Appendices to California's Regional Haze Plan

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A. California Environmental Quality Act

The California Environmental Quality Act (CEQA) requires that State and local agency projects be assessed for potential environmental impacts. A project includes activities undertaken by a public agency which may cause either a direct physical change in the environment or a reasonably foreseeable indirect change in the environment. Every project that requires a discretionary governmental approval will require at least some environmental review pursuant to CEQA, unless an exemption applies. The action of the California Air Resources Board (CARB) to approve or disapprove this Regional Haze Plan is discretionary. However, as explained in the Environmental Analysis section below, CARB determines the Regional Haze Plan is exempt from CEQA.

Environmental Analysis

Introduction

This appendix provides the basis for CARB's determination that the proposed Regional Haze Plan is exempt from the requirements of CEQA. A brief explanation of this determination is provided in section that follows. CARB's regulatory program, which involves the adoption, approval, amendment, or repeal of standards, rules, regulations, or plans for the protection and enhancement of the State's ambient air quality, has been certified by the California Secretary for Natural Resources under Public Resources Code section 21080.5 of CEQA (14 CCR 15251(d)). Public agencies with certified regulatory programs are exempt from certain CEQA requirements, including but not limited to, preparing environmental impact reports, negative declarations, and initial studies. CARB, as a lead agency, prepares a substitute environmental document (referred to as an "Environmental Analysis" or "EA") as part of the Staff Report prepared for a proposed action to comply with CEQA (17 CCR 60000-60008). When the Regional Haze Plan is finalized, a Notice of Exemption will be filed with the Office of the Secretary for the Natural Resources Agency and the State Clearinghouse for public inspection.

Analysis

CARB has determined that the proposed Regional Haze Plan is exempt from CEQA under the "general rule" or "common sense" exemption (14 CCR 15061(b)(3)). The common sense exemption states that a project is exempt from CEQA if "the activity is covered by the common sense exemption that CEQA applies only to projects which have the potential for causing a significant effect on the environment. Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA." The proposed Regional Haze Plan is also categorically exempt from CEQA under the "Class 8" exemption (14 CCR 15308) because it is an action taken by a regulatory agency for the protection of the environment.

The Regional Haze Plan was prepared to meet federal Clean Air Act requirements. The federal Clean Air Act requires states to develop and implement plans to reduce emissions that lead to visibility impairment in Class I areas. The requirements for state plans are detailed in U.S. Environmental Protection Agency's (EPA) 1999 Regional Haze Rule which was revised in 2017. California's first Regional Haze Plan was submitted to U.S. EPA in 2009. This is California's second Regional Haze Plan, addressing visibility in California's 29 Class I areas.

The Regional Haze Rule requires Regional Haze Plans to include the following key elements, which ultimately results in air quality agencies adopting or committing to adopting milestone visibility goals and measures to achieve requisite emission reductions:

- Visibility conditions in the state's Class I areas
- Emission inventories of haze causing pollutants
- Analysis of potential emission control measures
- Determination of emission controls necessary to make reasonable progress
- 2028 visibility goals for the state's Class I areas
- A long-term strategy to achieve visibility goals
- Consultation with states and federal land managers

The long-term strategy details the actions that will reduce emissions of haze forming pollutants that can affect visibility in Class I areas. The long-term strategy in this plan includes an emission reduction commitment of 40 tons per day by 2028. Emission reductions in this commitment will result from adoption and implementation of four regulatory measures:

- Advanced Clean Cars II
- Advanced Clean Trucks
- Heavy-Duty Inspection & Maintenance
- Heavy-Duty Omnibus

The Regional Haze Plan does not require CARB to undertake these measures; rather, CARB was already undertaking these measures independently, but is recognizing the reductions they are anticipated to achieve benefit regional haze. In other words, CARB's Regional Haze Plan does not create new measures or establish an obligation for CARB to undertake any new measures and instead contains a commitment from CARB to achieve an aggregate emissions reduction expected from measures already in development. Thus, the Regional Haze Plan would not cause a substantial change to the environment requiring additional environmental review. (See, e.g., *Sherwin-Williams Co. v SCAQMD* (2001) 86 Cal.App.4th 1258, 1286.)

The concepts included in these measures were initially detailed in CARB's 2016 State SIP Strategy document. Environmental Analysis for the concepts in the 2016 State SIP Strategy was released for public review in March 2017. The full text of the environmental analysis is available online: *https://ww3.arb.ca.gov/planning/sip/2016sip/rev2016statesip_ceqa.pdf*.

The rule making process for these measures was not initiated to meet the requirements of the Regional Haze Rule, rather the emission reductions achieved because of these measures will have a co-benefit for the regional haze program.

Nor would CARB's commitment to achieve an aggregate emissions reduction result in a significant adverse impact to the environment. Here, CARB quantified expected regional-haze-benefitting emissions reductions from measures CARB had already committed to develop (and, in some cases, has already developed) independently; CARB's quantification and commitment here in no way alters its previous commitments to develop (or adoption of) these measures. Thus, CARB's commitment here would have no possibility of causing any new or substantially increased significant impacts.

In addition to mobile sources, stationary sources were also considered in the analysis of potential emission control measures. Additional emission control options for one stationary source were evaluated in detail. Staff concluded that no additional reasonable emission control options were currently feasible for this facility.

The 2028 visibility goals established in this Regional Haze Plan for each of California's Class I areas are based on emission control measures that were already adopted at the time of the inventory development and the four emission control measures from the 2016 State SIP Strategy. The long-term strategy details the actions that will reduce emissions of haze forming pollutants that can affect visibility in Class I areas.

Based on CARB's review it can be seen with certainty that there is no possibility that the proposed Regional Haze Plan may result in a significant adverse impact on the environment. Further, the proposed action is designed to protect the environment and CARB found no substantial evidence indicating the proposal could adversely affect air quality or any other environmental resource area, or that any of the exceptions to the exemption applies (14 CCR 15300.2). Therefore, this activity is exempt from CEQA.

B. Documentation of Administrative Requirements

Documentation of administrative requirements of the Regional Haze Rule, not provided in other sections of this Regional Haze Plan, is provided in this Appendix.

Public Hearing Notice

The public hearing notice was posted on May 13, 2022. A copy of the notice is available on CARB's website at *https://ww2.arb.ca.gov/our-work/programs/california-state-implementation-plans/statewide-efforts/regional-haze*.

Public Comments on draft Regional Haze Plan with CARB Responses

+ Documentation will be added following close of comment period

CARB Resolution to Adopt Regional Haze Plan

+ Documentation will be added following adoption

CARB Transmittal Letter to U.S. EPA

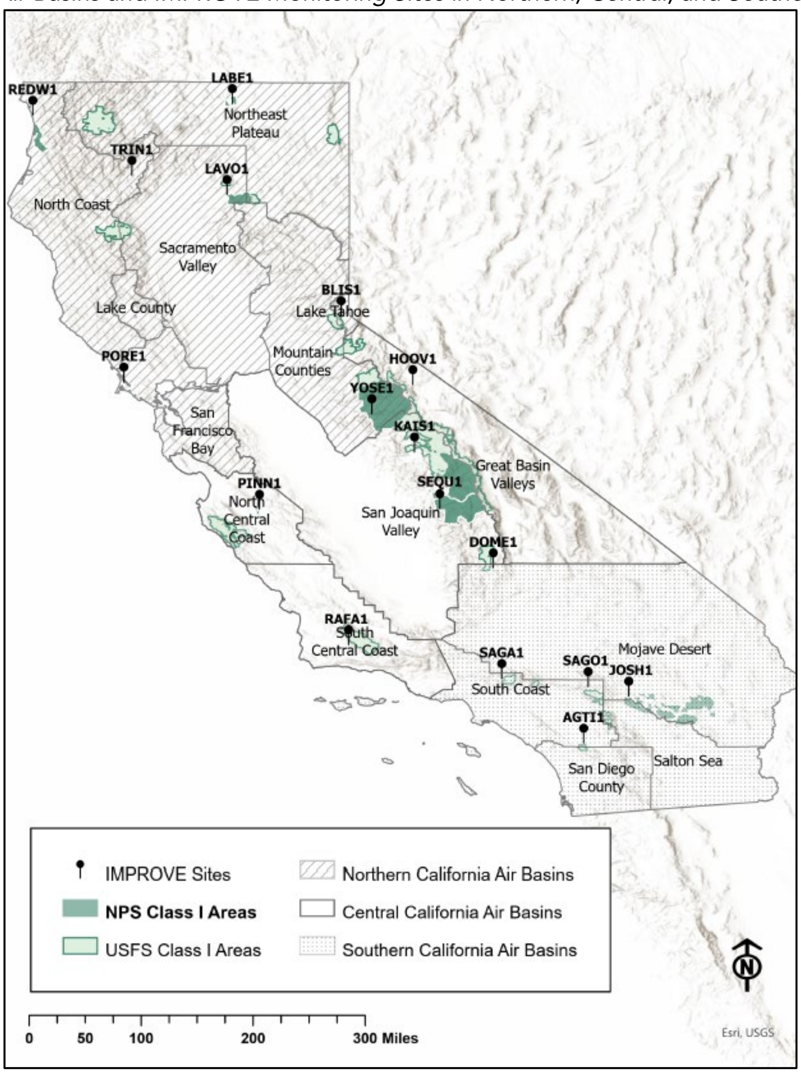
+ Documentation will be added prior to submission to U.S. EPA

C. Description of California's Mandatory Federal Class I Areas

This appendix provides descriptions of each of California's Class I areas, the representative monitoring sites, visibility conditions and projections, and sources of visibility impairment. Note that the acreage estimate for individual Class I areas varies among sources and has changed since the U.S. EPA's promulgation of the list of mandatory federal Class I areas in 1979. The acreage estimates provided in the following sections are from the original list published in 40 CFR 81.405.

Like the discussion in the main body of this Regional Haze Plan, Class I areas are organized in three regional groups (Northern, Central, and Southern California) based on the air basin where the representative Interagency Monitoring of Protected Visual Environments (IMPROVE) monitor is located. See Chapter 2 for an overview of each region.

Figure C-1: Air Basins and IMPROVE Monitoring Sites in Northern, Central, and Southern California



Northern California

Most of the Northern California region is sparsely populated, except for some areas in the Sacramento Valley and San Francisco Bay Air Basins. The capital city of Sacramento, with a population just over 500,000, is in the southern part of the Sacramento Valley Air Basin. The cities of Oakland, San Francisco, and San Jose, located within the San Francisco Air Basin, are home to more than two million people combined. When outlying suburban areas surrounding these urban cities are considered, the population is more than five million. Emissions from these populous areas contribute to visibility impairment in this region.

The movement of goods and people are a significant source of emissions throughout Northern California. The Port of Oakland, located in the San Francisco Bay Air Basin, is the eighth busiest port in the country. Ninety-nine percent of the containerized goods that move through Northern California are discharged at the Port, with most of the container volume coming from Asia. In 2017 alone, a total of 2,420,837 twenty-foot equivalent units (TEU) moved through the Port of Oakland.[1]

The San Francisco International Airport, also located in the San Francisco Bay Air Basin, consistently ranks among the ten busiest airports in the nation. In 2019, more than 27 million passengers traveled through the airport. San Jose, Oakland, and Sacramento International Airports are also major air transportation hubs that annually rank among the top 50 busiest airports in the nation. In 2019, more than 20 million passengers enplaned at these three airports combined.[2]

The Sacramento Valley Air Basin is a major transportation corridor. Miles of freight lines and interstate highways transit this air basin. Average daily traffic volume in the most remote sections of the air basin exceeds 15,000 vehicles, with around 30 percent being heavy-duty trucks.[3] Emissions from mobile sources are the primary anthropogenic source of haze pollutants in this region.

Emissions from the Sacramento Valley and San Francisco Bay Air Basins account for most of the region's emissions. Emissions from the Sacramento Valley and San Francisco Bay Air Basins accounted for 31 percent and 47 percent of 2014 oxides of nitrogen (NOx) emissions in this region, respectively. Mobile sources are the dominant NOx emission source sector in each air basin.

Seven IMPROVE monitoring sites are in the Northern California region. From north to south, the monitoring sites in this region are located at Lava Beds National Monument, Redwood National Park, Trinity Wilderness, Lassen Volcanic National Park, DL Bliss State Park, Point

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[1] *https://www.oaklandseaport.com/performance/facts-figures/*

[2] *https://www.bts.gov/content/passengers-boarded-top-50-us-airports*

[3] *https://dot.ca.gov/programs/traffic-operations/census*

Reyes National Seashore, and Yosemite National Park. The following section provides an overview of each monitoring site and Class I areas characterized by data collected at the site, as well as a description of visibility conditions and source apportionment for each location.

Lava Beds National Monument (LABE1) IMPROVE Monitoring Site

The LABE1 monitoring site, shown in Figure C-2, is in the southern portion of Lava Beds National Monument at 4,790 feet (1,460 m) asl. The monitoring site was established in March 2000 southeast of the Lava Beds Visitor Center. The Indian Well Campground is located about a half mile northeast of the site. It has 31 developed camp sites and is lightly used with approximately 10,000 overnight visitor stays annually.[4] Monitoring data collected at this site are representative of visibility conditions in Lava Beds National Monument and the South Warner Wilderness Area.

Figure C-2: Photograph looking southwest toward LABE1 Monitoring Site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

Lava Beds National Monument includes 28,640 acres along the north flank of Medicine Lake Volcano in the southern Cascades Range. The arid landscape features buttes and calderas that underscore the active volcanic nature of the region. The South Warner Wilderness Area covers 68,507 acres along the southern end of the Warner Mountains of northeast California. The remote area is lightly visited and minimally developed. Lava Beds National Monument and the South Warner Wilderness Area are in the Northeast Plateau Air Basin.

As shown in Table C-1, visibility impairment on the clearest days during the baseline period was 3.2 deciviews (dv). Visibility impairment on the clearest days decreased by 0.7 dv between the baseline and the current periods. During the current period, visibility impairment was 2.5 dv which is equivalent to a visual range of 189 miles (304 km).

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[4] https://irma.nps.gov/STATS/Reports/Park/LABE

Visibility impairment on the most impaired days during the baseline period was 11.3 dv. Visibility impairment decreased by 1.6 dv between the baseline and the current periods. On the most impaired days during the current period visibility impairment was 9.7 dv, which is equivalent to a visual range of 92 miles (148 km). Between the baseline and current periods, visibility improved by an average of 0.11 dv each year. This rate of improvement is faster than the uniform rate of progress (URP) adjusted to account for international emissions and prescribed fire as well as the unadjusted URP.

Table C-1: Visibility Tracking Metrics for Lava Beds National Monument and South Warner Wilderness Area

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	3.2	2.5	1.3	0.7 dv	1.2 dv	--	--
Most Impaired	11.3	9.7	6.2	1.6 dv	3.5 dv	0.09 dv/year (0.07 dv/year)	0.11 dv/year

Monitoring data, shown in Figures C-3 and C-4, indicate that on the clearest and most impaired days, organic mass and ammonium sulfate account for the largest share of light extinction at the LABE1 monitor. Between the baseline and the current periods, light extinction from organic mass decreased by 18 percent on the clearest days and by 10 percent most impaired days. Light extinction from ammonium sulfate decreased by 27 percent on the clearest and by 26 percent most impaired days.

Figure C-3: Average Extinction Composition for LABE1 on the Clearest Days

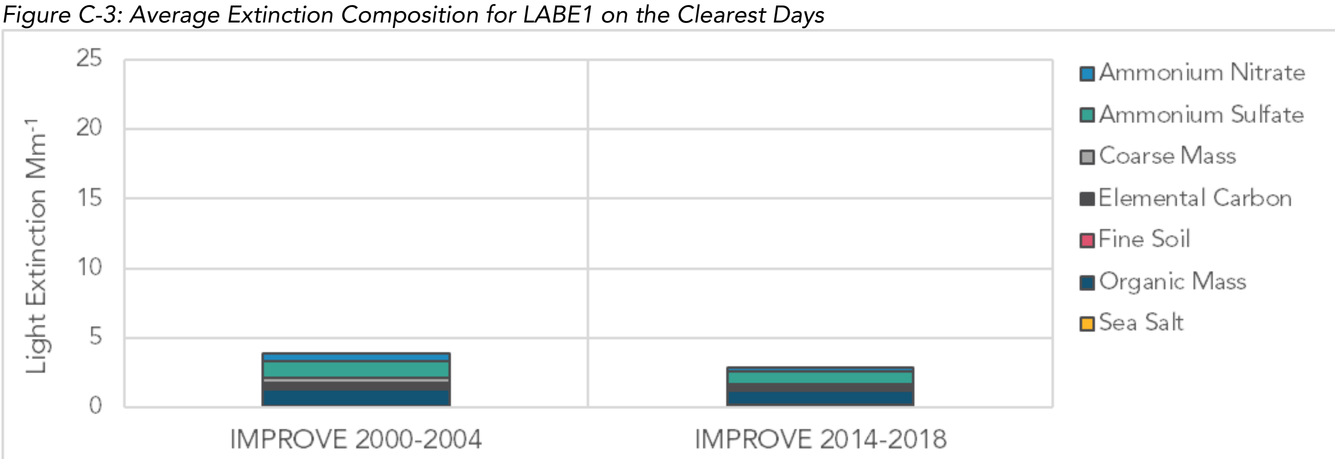
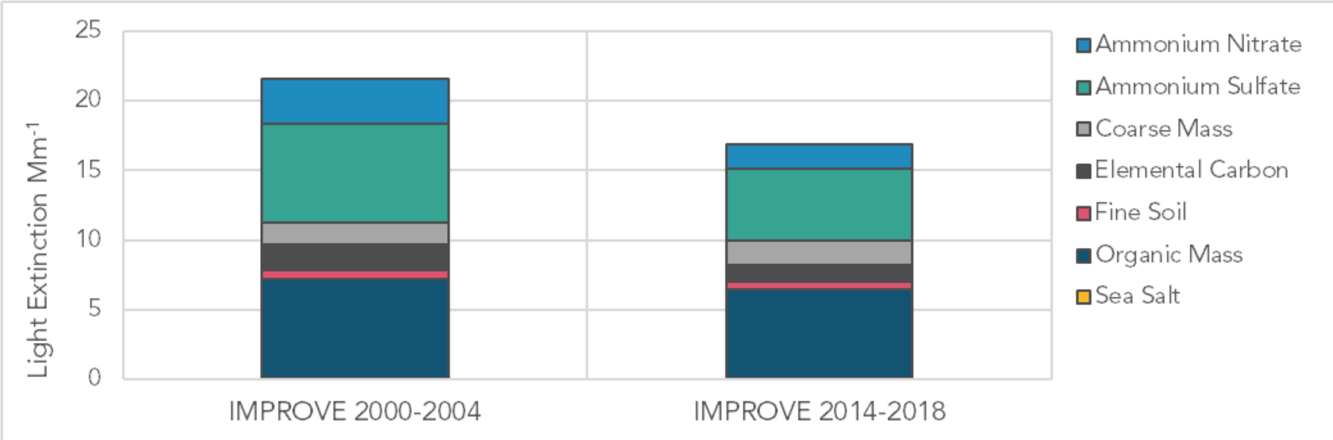
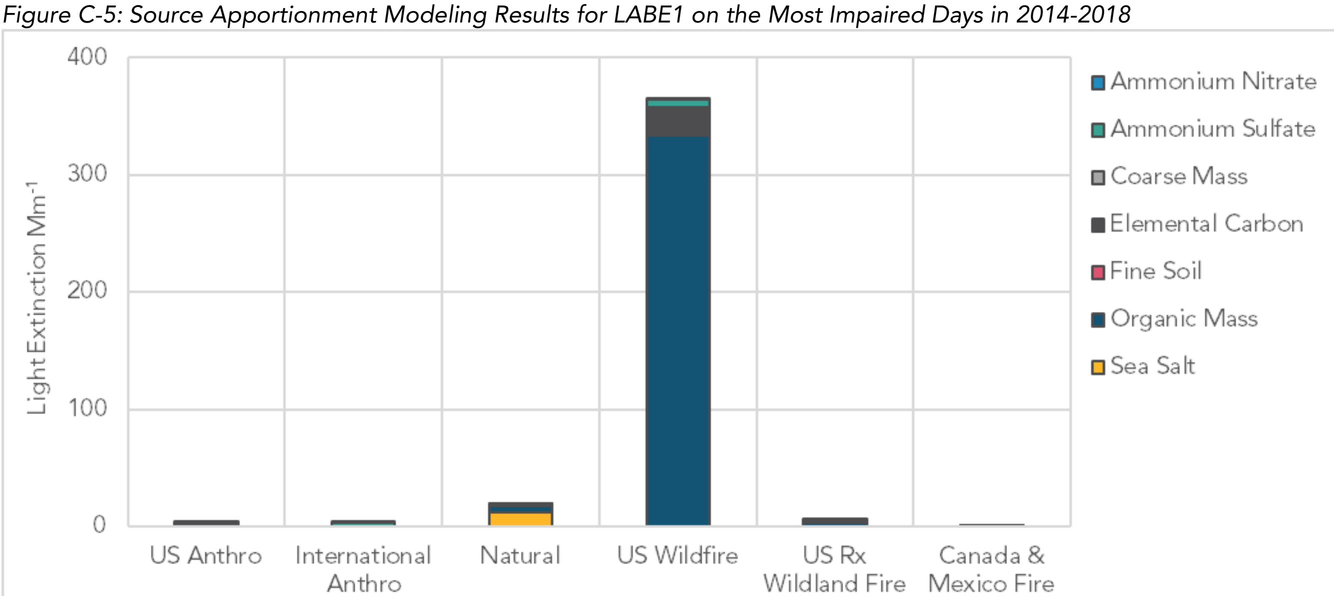


Figure C-4: Average Extinction Composition for LABE1 on the Most Impaired Days



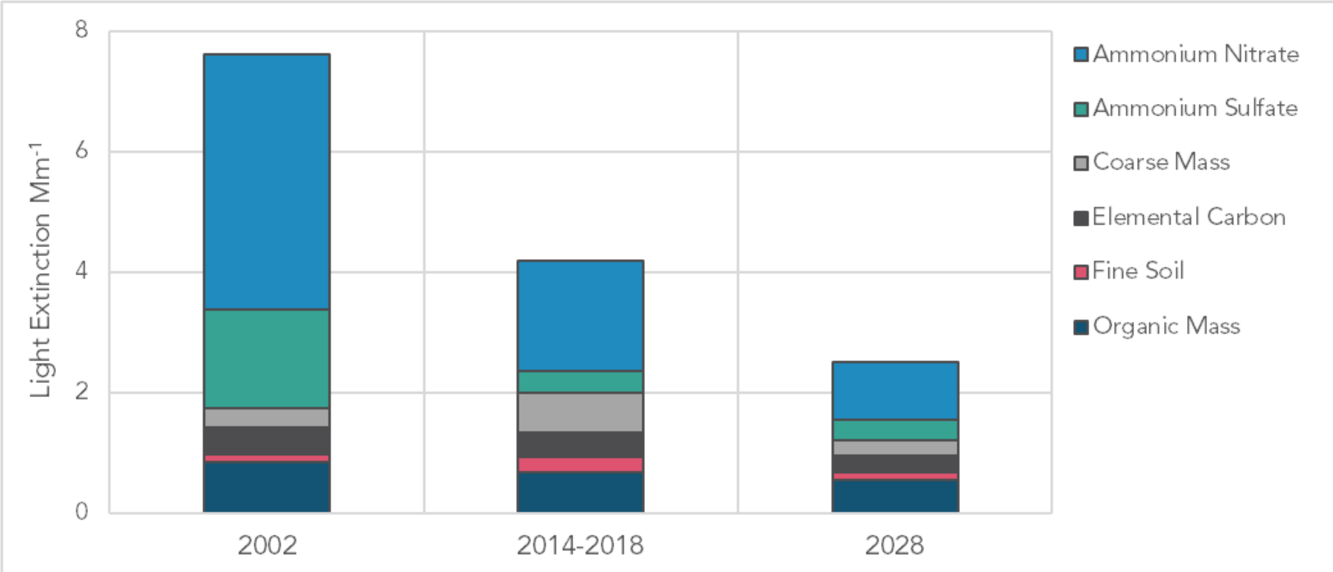
Source apportionment modeling, shown in Figure C-5, indicates that wildfires are the dominant source of visibility reducing particles at the LABE1 monitoring site. Prescribed wildland fire emissions and other non-fire natural sources also contribute to impaired visibility. U.S. anthropogenic emissions make a relatively small contribution to visibility impairment.

Figure C-5: Source Apportionment Modeling Results for LABE1 on the Most Impaired Days in 2014-2018



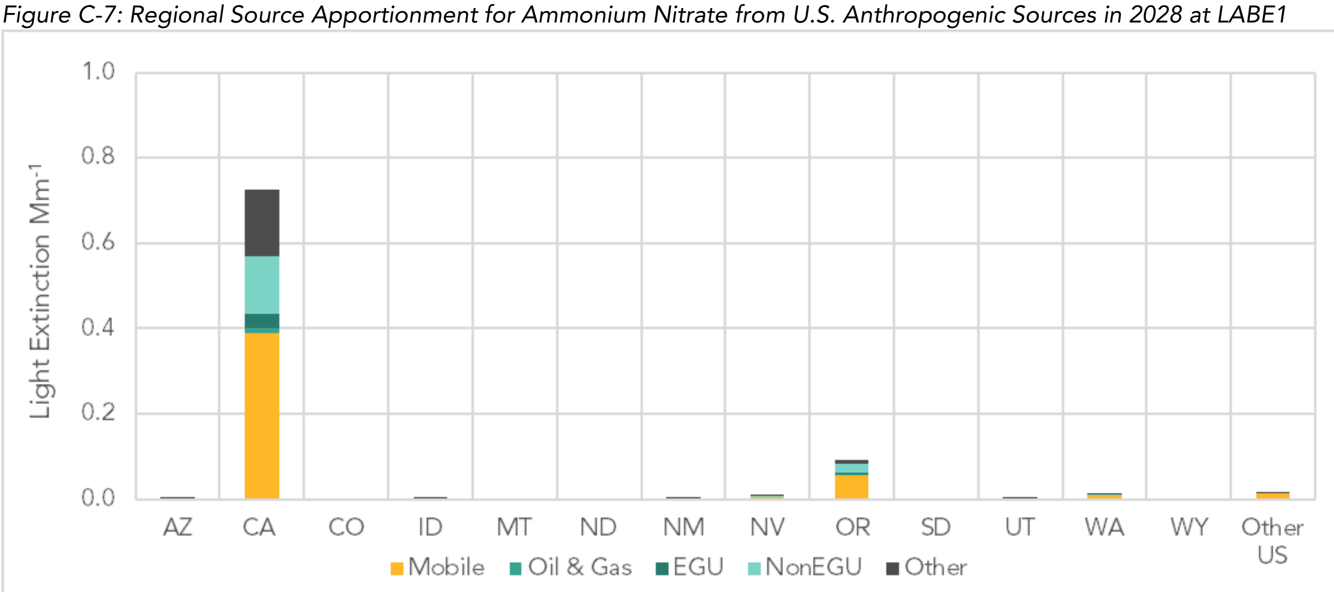
As shown in Figure C-6, the portion of light extinction attributed to U.S. sources is dominated by ammonium nitrate. Between the current period and 2028, baseline (adopted) emission controls are expected to reduce light extinction attributable to ammonium nitrate by 50 percent. Modest reductions are projected for other PM species. Ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. emission sources in 2028.

Figure C-6: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at LABE1 on the Most Impaired Days



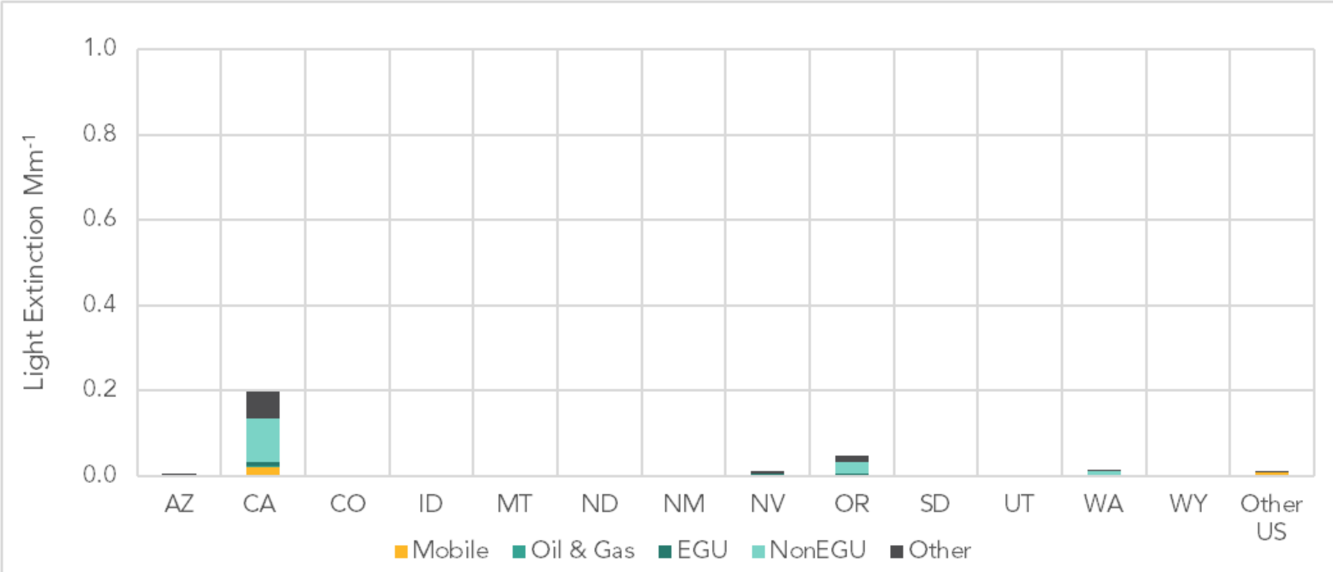
The results of regional source apportionment modeling, shown in Figure C-7, indicates that California mobile sources will continue to be the largest regional source of ammonium nitrate in 2028. These results suggest that continued efforts to reduce emissions from the mobile source sector in California will be an important part of improving visibility.

Figure C-7: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at LABE1



As shown in Figure C-8, California emissions account for the largest portion of the small share of light extinction from ammonium sulfate attributable to regional anthropogenic emissions. However, the projected portion of light extinction from ammonium sulfate attributable to regional sources is 0.3 Mm^{-1}, about a third of the portion from ammonium nitrate.

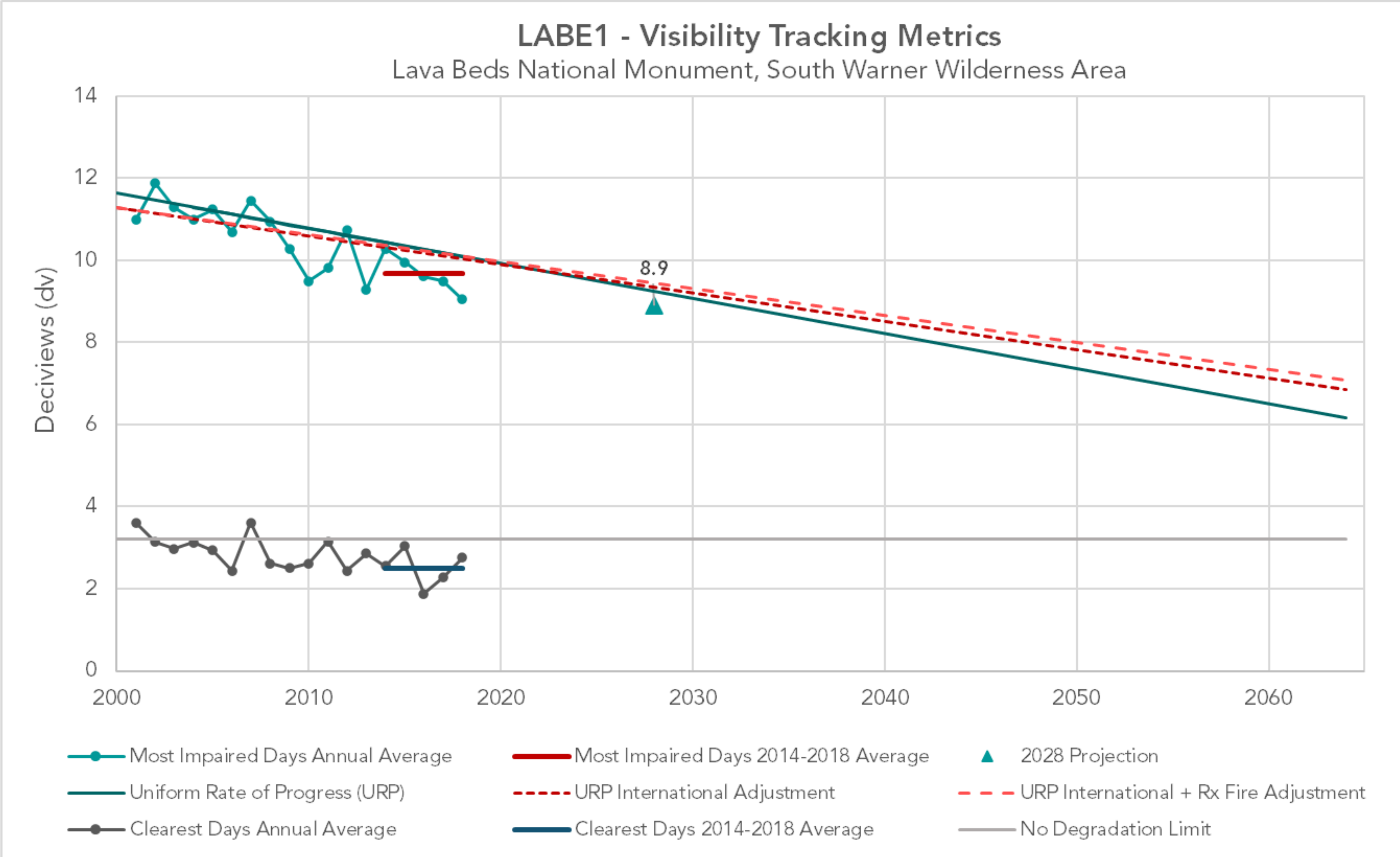
Figure C-8: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at LABE1



California's long-term strategy for regional haze is focused on improving visibility through reduction of NOx emissions from mobile sources. Reducing emissions of NOx, which generally drives the formation of ammonium nitrate in California, will lead to a reduction in haze pollutants in Lava Beds National Monument and the South Warner Wilderness Area. Regional photochemical modeling analyses support this conclusion.

The current and projected trends for the visibility tracking metrics at Lava Beds National Monument and the South Warner Wilderness Area are shown in Figure C-9. Accounting for baseline (adopted) emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 8.9 dv in 2028, which is equivalent to a visual range of 100 miles (160 km). The 2028 projection is below the adjusted glidepath, which accounts for international and wildland prescribed fire emissions, indicating that the site is on track to meet 2064 visibility targets.

Figure C-9: Visibility Tracking Metrics and Projections for Lava Beds National Monument and the South Warner Wilderness Area



Redwood National Park (REDW1) IMPROVE Monitoring Site

The REDW1 monitoring site, shown below in Figure C-10, is in the central portion of Redwood National Park at 801 feet (244 m) asl. The monitoring site was established in March 1988 at a former U.S. Air Force radar facility. The site is less than a mile east of the Pacific Ocean and north of the Klamath River. Data collected at the site are representative of visibility conditions in Redwood National Park.

Figure C-10: Photograph looking northwest towards REDW1 Monitoring Site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

Redwood National Park covers 27,792 acres along the coast of northern California and includes stands of coastal redwoods, fir, Sitka spruce, as well as prairies, oak woodlands, and rugged coastline. Redwood National Park is in the North Coast Air Basin. Annual park visitation hovers around 500,000.[5] Redwood National Park is contiguous with several of California Redwoods State Parks and the area has been cooperatively managed since 1994.

As shown in Table C-2, visibility impairment on the clearest days during the baseline period was 6.1 dv. Visibility impairment on the clearest days decreased by 0.8 dv between the baseline and the current periods. Visibility impairment was 5.3 dv during the current period, which is equivalent to a visual range of 143 miles (230 km).

On the most impaired days, visibility impairment was 13.7 dv during the baseline period and 12.6 dv during the current period, which is equivalent to a visual range of 69 miles (111 km). Between the baseline and current periods, visibility on the most impaired days improved by

[5] *https://irma.nps.gov/STATS/Reports/Park/REDW*

an average of 0.08 dv each year. This rate of improvement is faster than the uniform rate of progress adjusted to account for international emissions and prescribed fire.

Table C-2: Visibility Tracking Metrics for REDW1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	6.1	5.3	3.5	0.8 dv	1.8 dv	--	--
Most Impaired	13.7	12.6	8.6	1.1 dv	4.0 dv	0.09 dv/year (0.07 dv/year)	0.08 dv/year

Monitoring data, shown in Figures C-11 and C-12, indicate that ammonium sulfate accounts for the largest share of light extinction on the clearest and most impaired days at the REDW1 monitoring site. Emissions from offshore shipping routinely impact this area. Between the baseline and the current periods, CARB implemented low-sulfur diesel regulations that apply to ocean-going vessels operating in California waters. The implementation of these regulations has had a measurable impact on reducing sulfur emissions from ocean-going vessels. Between the baseline and the current periods, light extinction from ammonium sulfate decreased by 71 percent on the clearest days and by 65 percent on the most impaired days.

Figure C-11: Average Extinction Composition for REDW1 on the Clearest Days

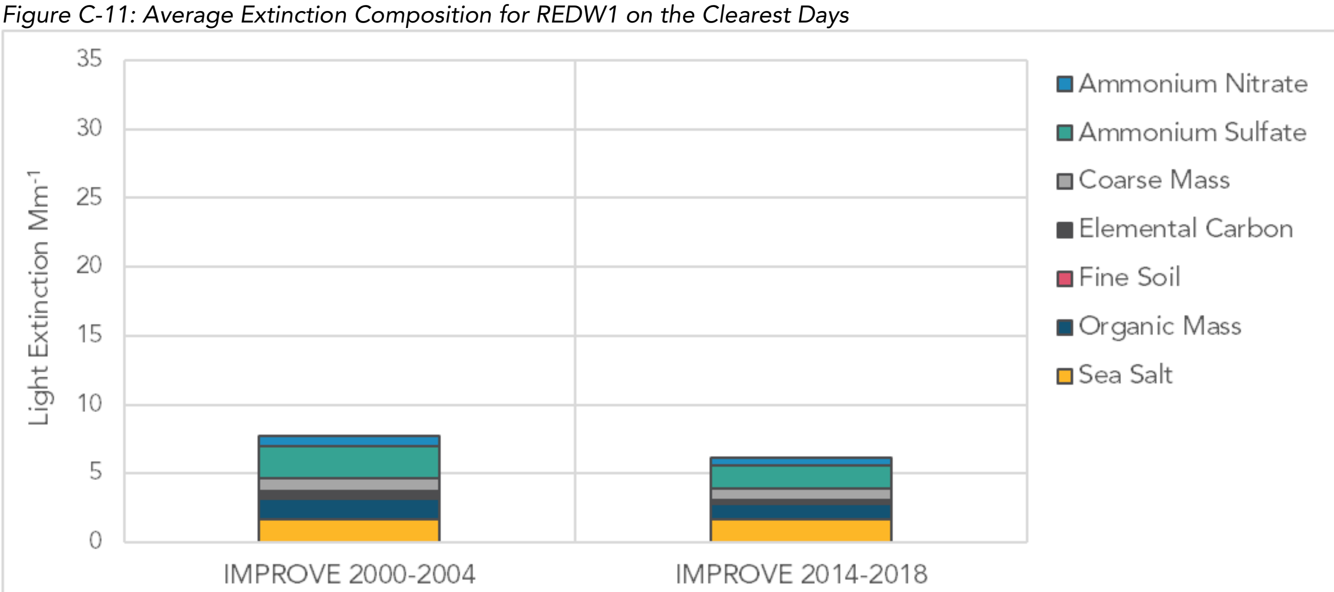
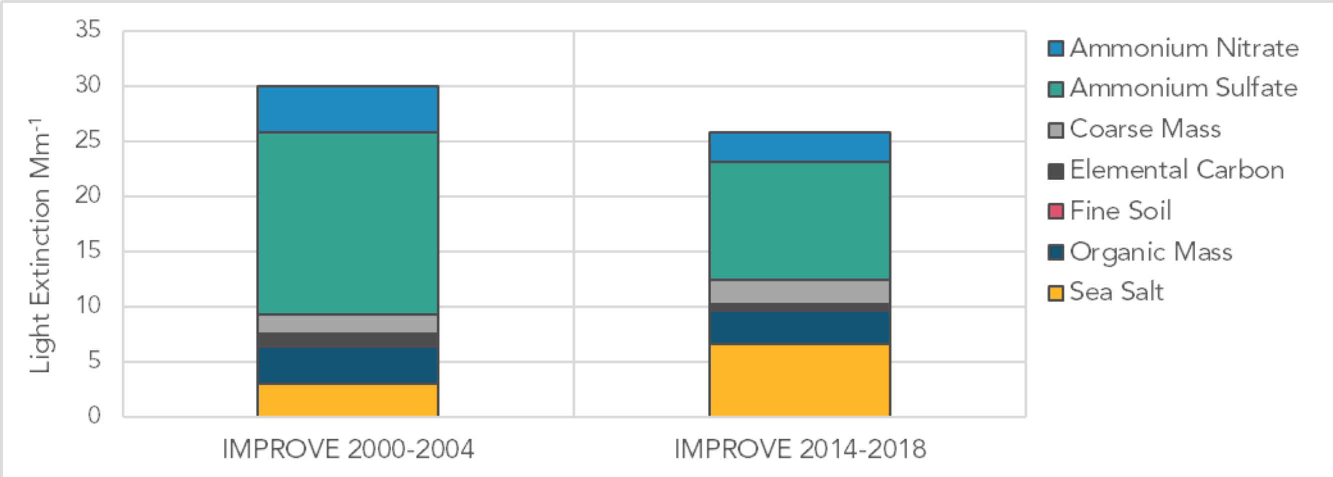
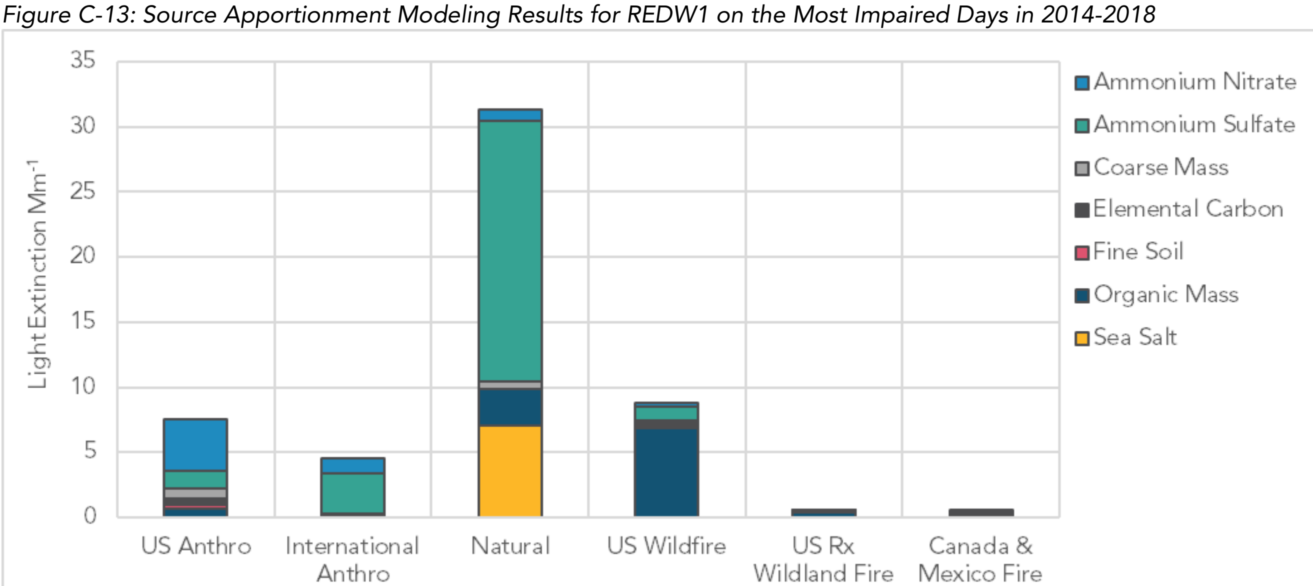


Figure C-12: Average Extinction Composition for REDW1 on the Most Impaired Days



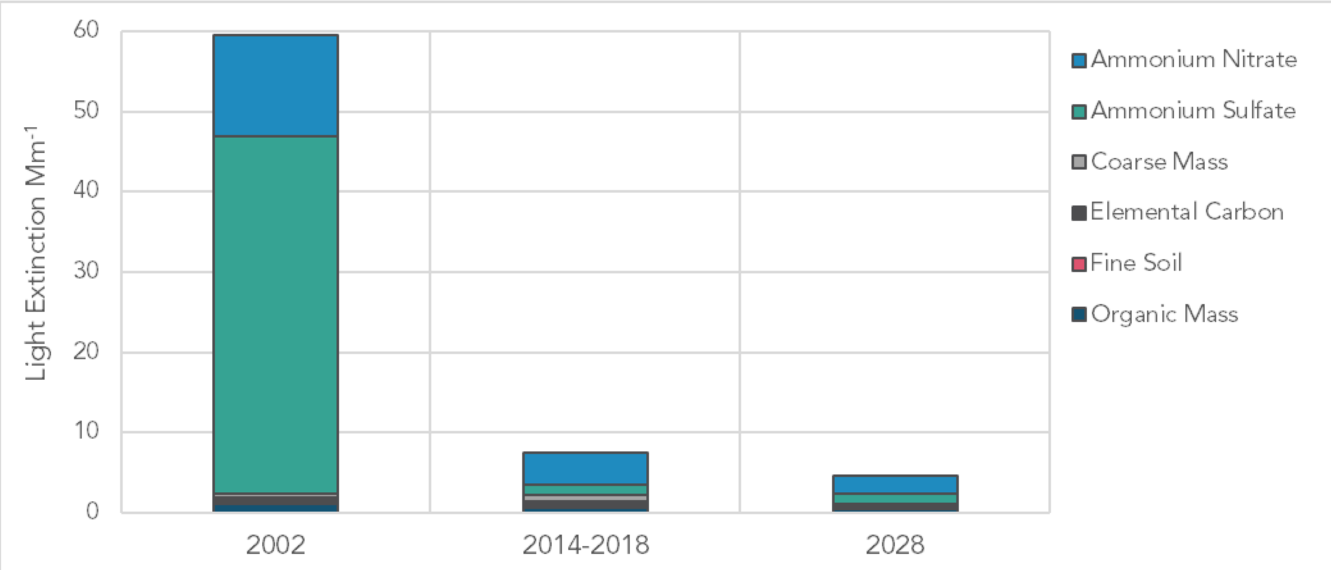
Source apportionment modeling, shown in Figure C-13, indicates that natural emissions are the dominant source of visibility reducing particles measured at the REDW1 monitoring site. Ammonium sulfate and sea salt account for the largest portions of light extinction attributable to natural sources. Wildfire, international anthropogenic, and U.S. anthropogenic emission sources also contribute to visibility impairment. Organic mass and ammonium sulfate account for the largest share visibility reducing particles attributable to U.S. wildfire and international anthropogenic sources on the most impaired days, respectively.

Figure C-13: Source Apportionment Modeling Results for REDW1 on the Most Impaired Days in 2014-2018



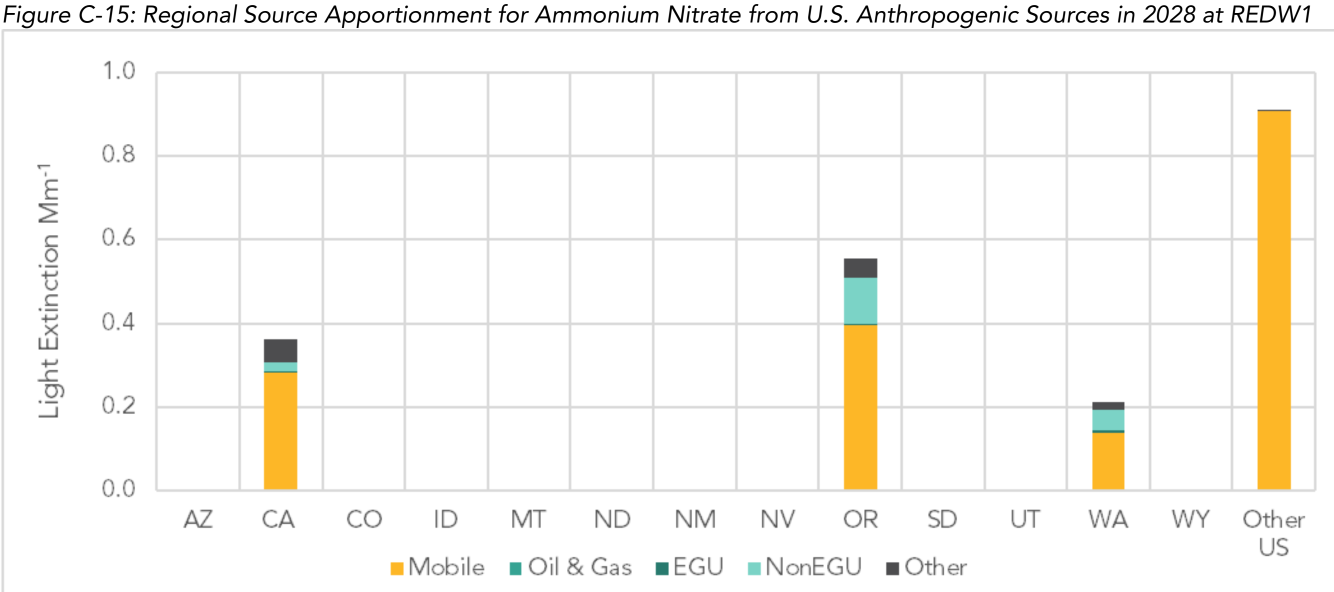
As shown in Figure C-14, ammonium sulfate impacts have been reduced dramatically since the baseline period and light extinction attributable to U.S. sources was dominated by ammonium nitrate during the current period. Between the current period and 2028, adopted emission controls are expected to reduce light extinction attributable to ammonium nitrate from U.S. sources by 45 percent. Projections indicate that ammonium nitrate will continue to account for the largest share of light extinction attributable to U.S. emission sources.

Figure C-14: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at REDW1 on the Most Impaired Days



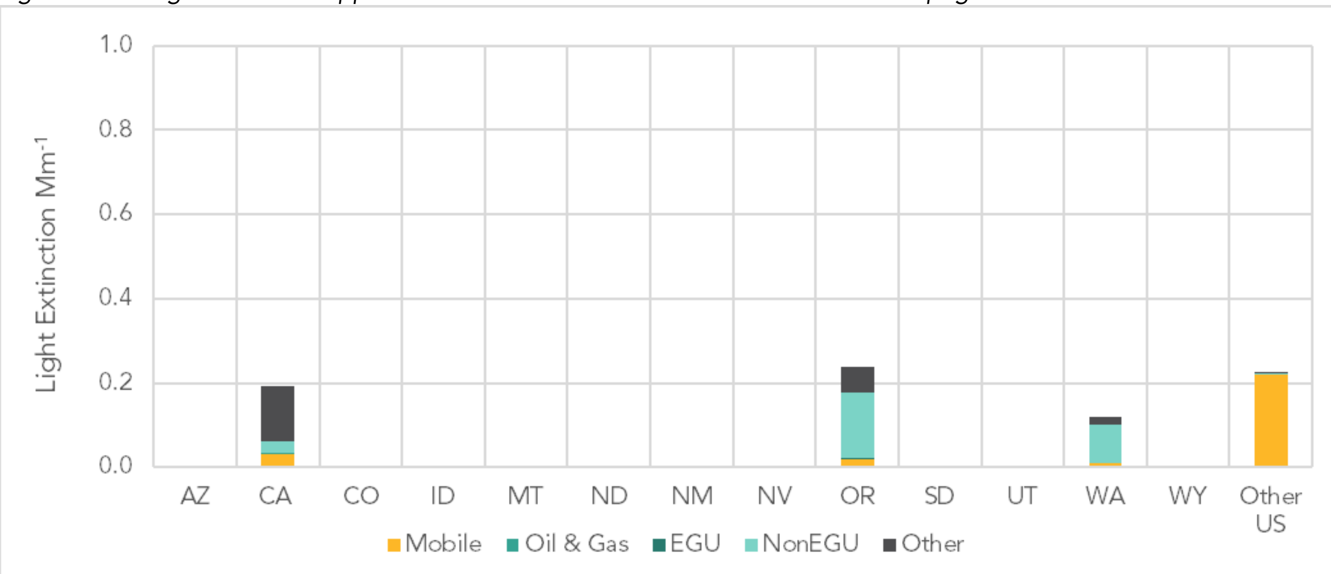
Regional source apportionment projections, shown in Figure C-15, indicates that mobile sources will continue to be the largest regional source of ammonium nitrate in 2028. These results underscore the need to continue efforts to reduce emissions from mobile source sectors. Efforts focused on mobile source control programs will yield a wide range of benefits, including improved visibility.

Figure C-15: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at REDW1



As shown in Figure C-16, light extinction from ammonium sulfate is projected to amount to less than half of the amount of light extinction from ammonium nitrate. Regional source apportionment results indicate that a combination of regional emissions contribute to ammonium sulfate on the most impaired days. The largest single source group contribution is from "Other US" mobile sources, which includes emissions from ocean-going vessels operating off the coast in U.S. waters.

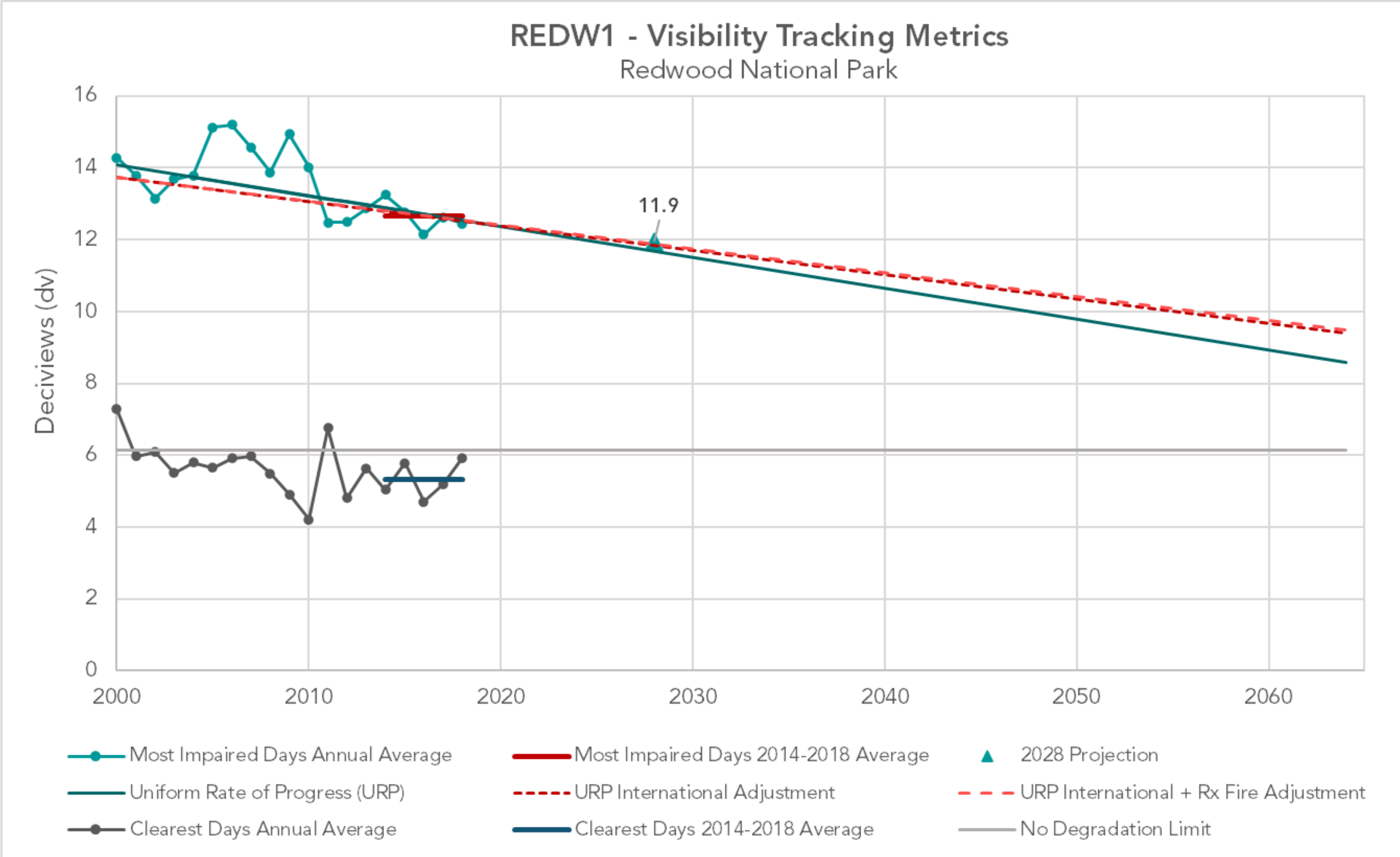
Figure C-16: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at REDW1



California's long-term strategy for regional haze is focused on improving visibility through reduction of NOx emissions from mobile sources. This strategy is expected to lead to improved visibility at Redwood National Park. However, offshore shipping emissions, the primary component of the "Other US" regional source group in Figures C-15 and C-16, is projected to have a continued impact on visibility at this coastal site. Action by the U.S. EPA in cooperation with the International Maritime Organization could help achieve emission reductions from offshore shipping and accelerate the pace of visibility improvement for Redwood National Park and other Class I areas influenced by offshore emissions.

The current and projected trends for visibility tracking metrics at Redwood National Park are shown in Figure C-17. Accounting for baseline (adopted) emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected be 11.9 dv in 2028, which is equivalent to a visual range of 74 miles (119 km). The 2028 projection is below the adjusted glidepath, which accounts for international and wildland prescribed fire emissions, indicating that the site is on track to meet 2064 visibility targets.

Figure C-17: Visibility Tracking Metrics and Projections for Redwood National Park



Trinity National Forest (TRIN1) IMPROVE Monitoring Site

The TRIN1 monitoring site, shown below in Figure C-18, is in the Trinity National Forest at 3,327 feet (1,014 m) asl. The monitoring site was established in October 2000, just south of Trinity River Conservation Camp #3. A helipad is located just north of the site. Data collected at this site are representative of visibility conditions in the Marble Mountain Wilderness Area and Yolla Bolly-Middle Eel Wilderness Area. While not in a Class I area, the TRIN1 monitor is in a rural area equidistant between the Marble Mountain and Yolla Bolly-Middle Eel Wilderness Areas at a location that is accessible and equipped with reliable power.

Figure C-18: Photograph looking north towards the TRIN1 Monitoring Site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

The Marble Mountain Wilderness Area spans 213,743 acres. The landscape is characterized by craggy mountain peaks, high elevation meadows, lakes, deep glacial-carved valleys, and dense forests. The Marble Mountain Wilderness Area is in the Northeast Plateau Air Basin. The Yolla Bolly-Middle Eel Wilderness Area is remote and rugged, covering 109,091 acres and straddling the border of the North Coast and Sacramento Valley Air Basins. The TRIN1 monitoring site is in the North Coast Air Basin.

As shown in Table C-3, visibility impairment on the clearest days during the baseline period was 3.4 dv. Visibility impairment on the clearest days decreased by 0.3 dv between the baseline and current periods. During the current period, visibility impairment was 3.1 dv, which is equivalent to a visual range of 178 miles (286 km).

Visibility impairment on the most impaired days during the baseline period was 11.9 dv. Visibility impairment decreased by 1.5 dv between baseline monitoring period and the current period. During the current period, visibility impairment was 10.4 dv, which is equivalent to a visual range of 86 miles (138 km).

Table C-3: Visibility Tracking Metrics for TRIN1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjustment)	Current Rate of Progress
Clearest	3.4	3.1	1.2	0.3 dv	1.9 dv	--	--
Most Impaired	11.9	10.4	6.5	1.5 dv	3.9 dv	0.09 dv/year (0.05 dv/year)	0.11 dv/year

Monitoring data, shown in Figures C-19 and C-20, indicate that organic mass and ammonium sulfate have the most dominant impact on light extinction at the TRIN1 monitor on both the clearest days and the most impaired days. Between the baseline monitoring period and the current period, light extinction from organic mass decreased by 5 percent on the clearest days and by 15 percent on the most impaired days. During this same time period, light extinction from ammonium sulfate decreased by 19 percent on the clearest days and by 20 percent on the most impaired days.

Figure C-19: Average Extinction Composition for TRIN1 on the Clearest Days

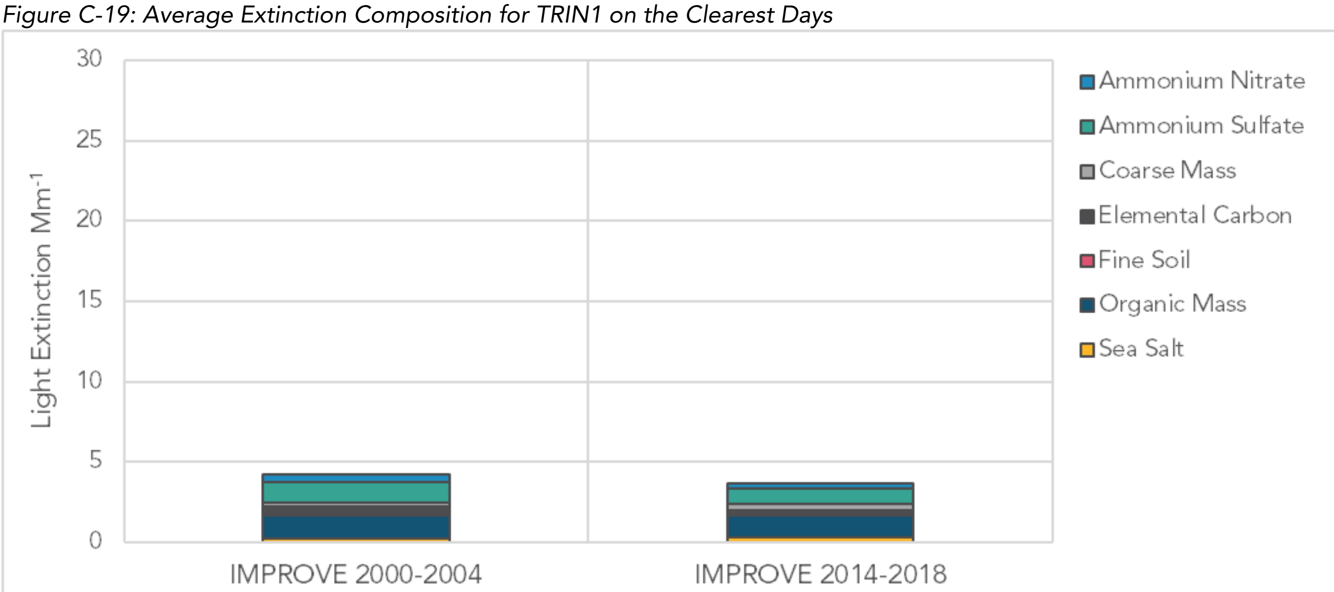
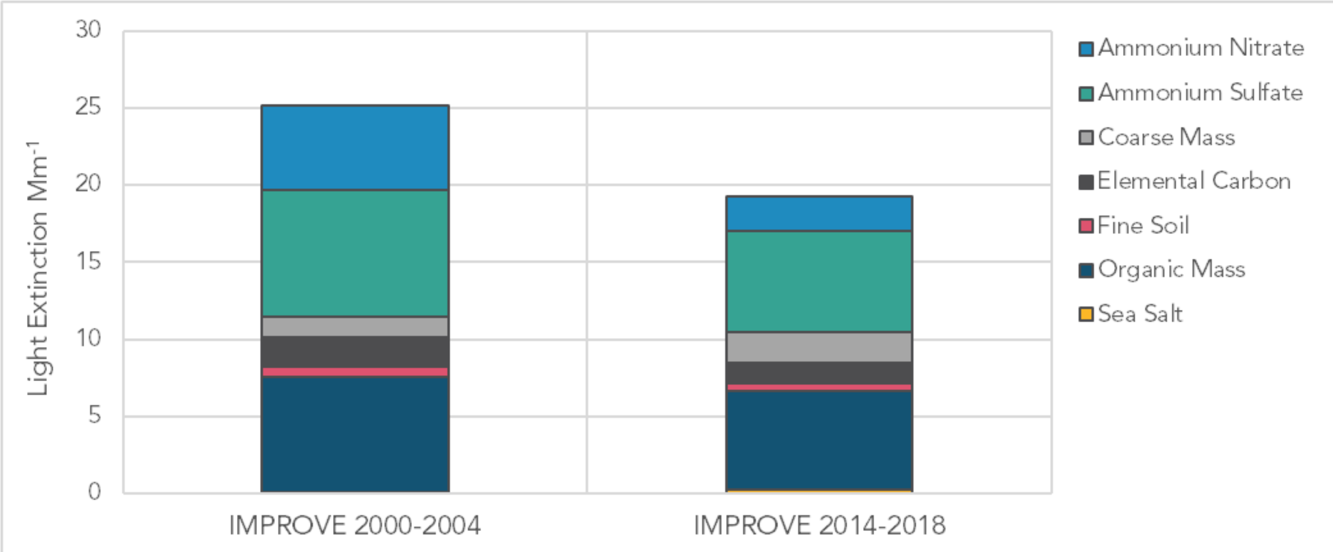
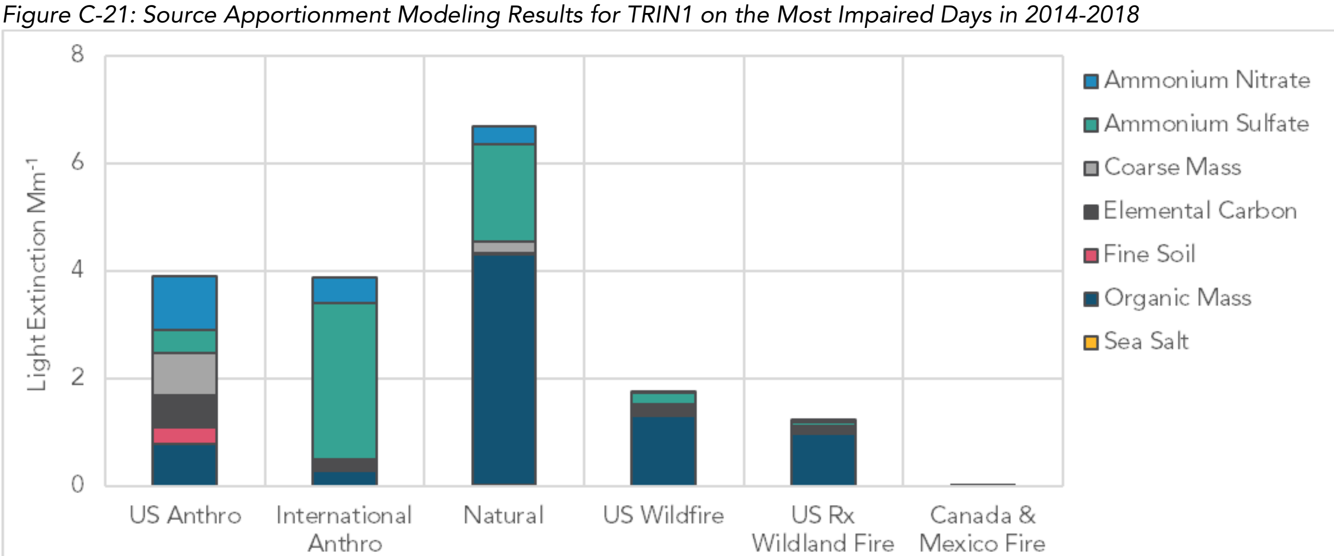


Figure C-20: Average Extinction Composition for TRIN1 on the Most Impaired Days



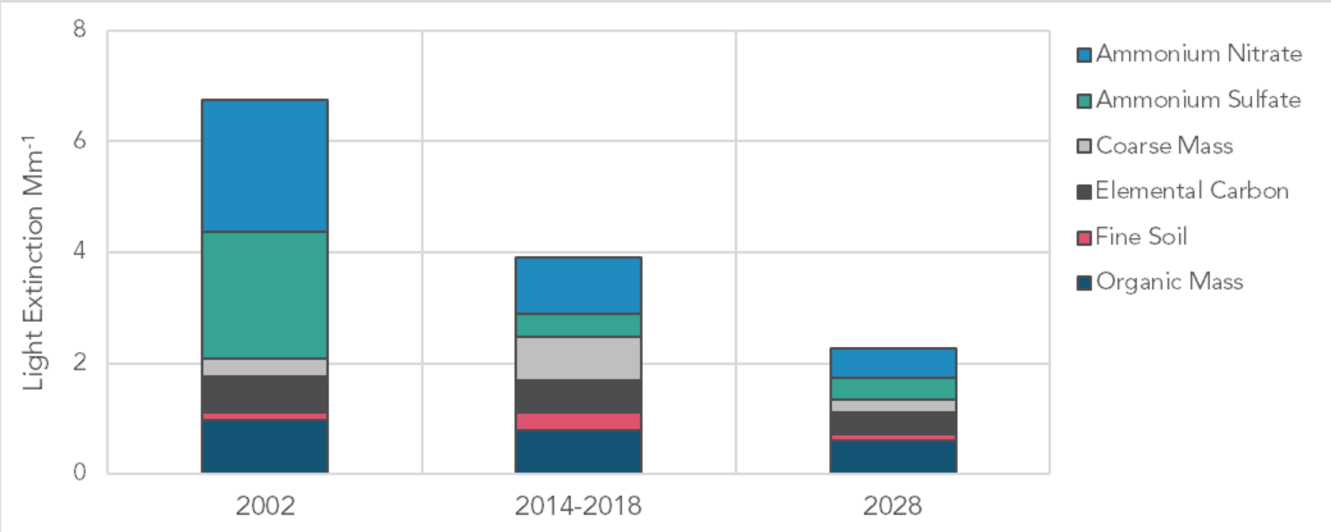
Source apportionment modeling, shown in Figure C-21, indicates that natural emissions are the dominant source of light extinction from visibility reducing particles measured at the TRIN1 monitor on the most impaired days. Emissions from U.S. sources, international sources, and fire also contribute to visibility impairment. Organic mass is the dominant PM species in the light extinction budget for natural and fire source groups on the most impaired days, whereas ammonium sulfate accounts for the largest portion of international emissions.

Figure C-21: Source Apportionment Modeling Results for TRIN1 on the Most Impaired Days in 2014-2018



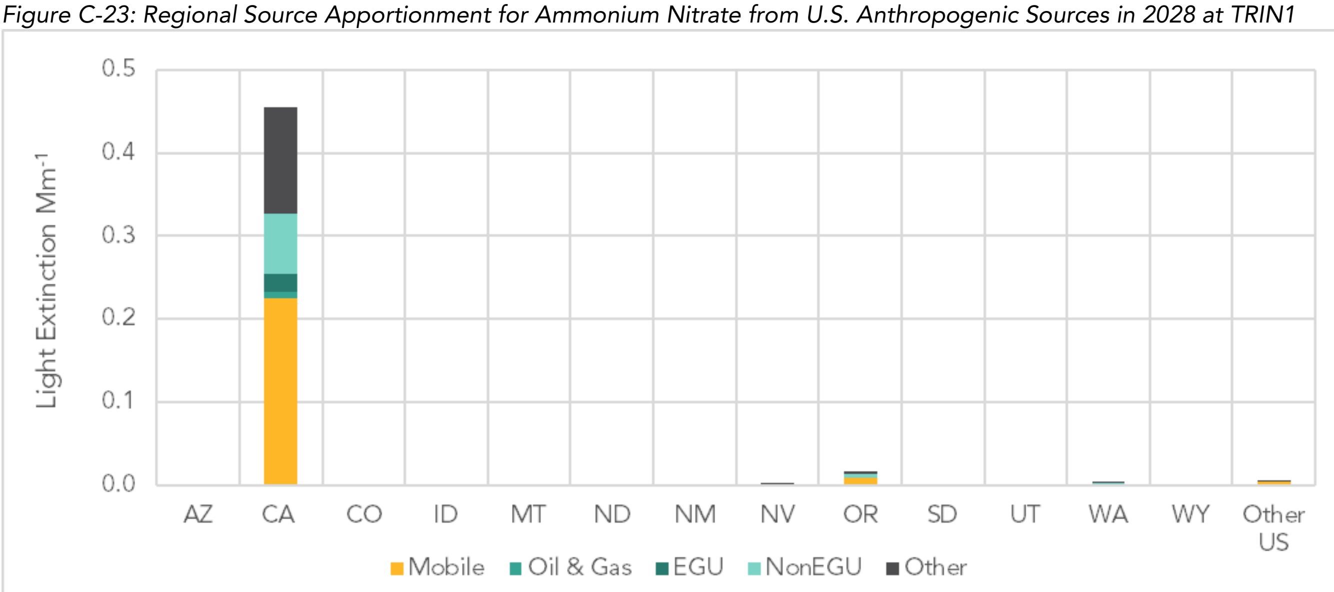
As shown in Figure C-22, ammonium nitrate accounted for the largest share of light extinction attributed to U.S. sources during the baseline and current periods. Ammonium nitrate was followed closely by ammonium sulfate during the baseline period and organic mass in the current period, both of which are species that can be emitted from combustion processes. Between the current period and 2028, adopted emission controls are expected to reduce ammonium nitrate by 50 percent. A reduction of 25 percent is expected for light extinction attributed to the U.S. portion of organic mass.

Figure C-22: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at TRIN1 on the Most Impaired Days



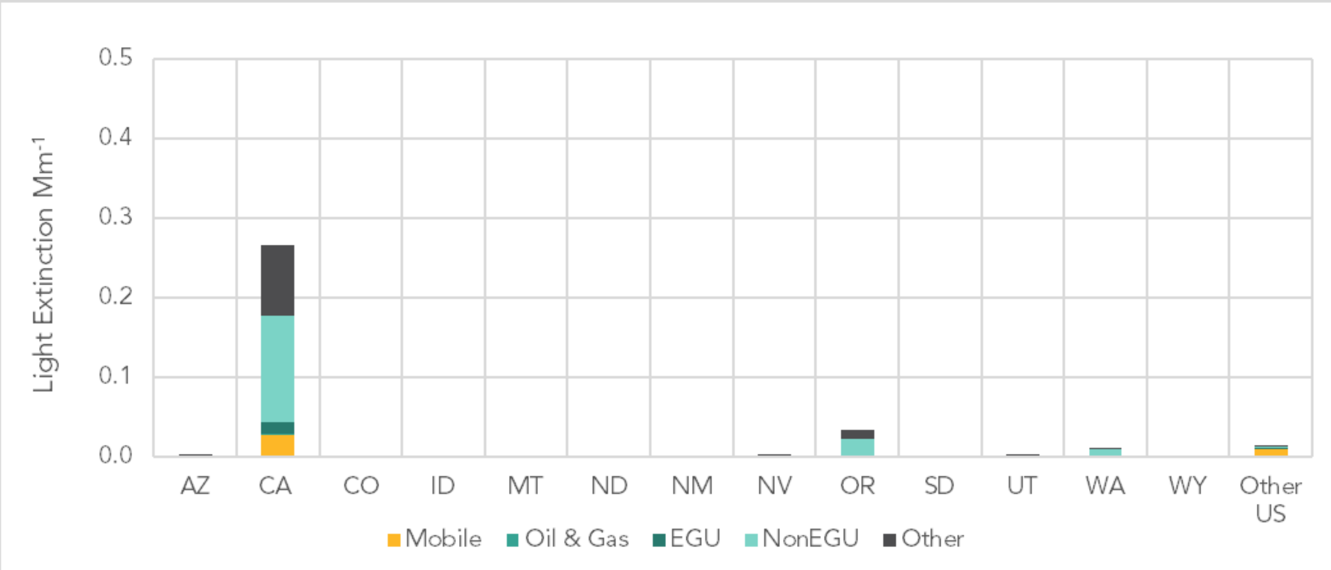
Regional source apportionment modeling, shown in Figure C-23, indicates that mobile sources in California are projected to account for the largest share of light extinction attributable to ammonium nitrate in 2028. California's strategy for regional haze is focused on improving visibility through reduction of NOx emissions from mobile sources. This strategy is expected to lead to visibility improvement in the Marble Mountain and Yolla Bolly-Middle Eel Wilderness Areas.

Figure C-23: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at TRIN1



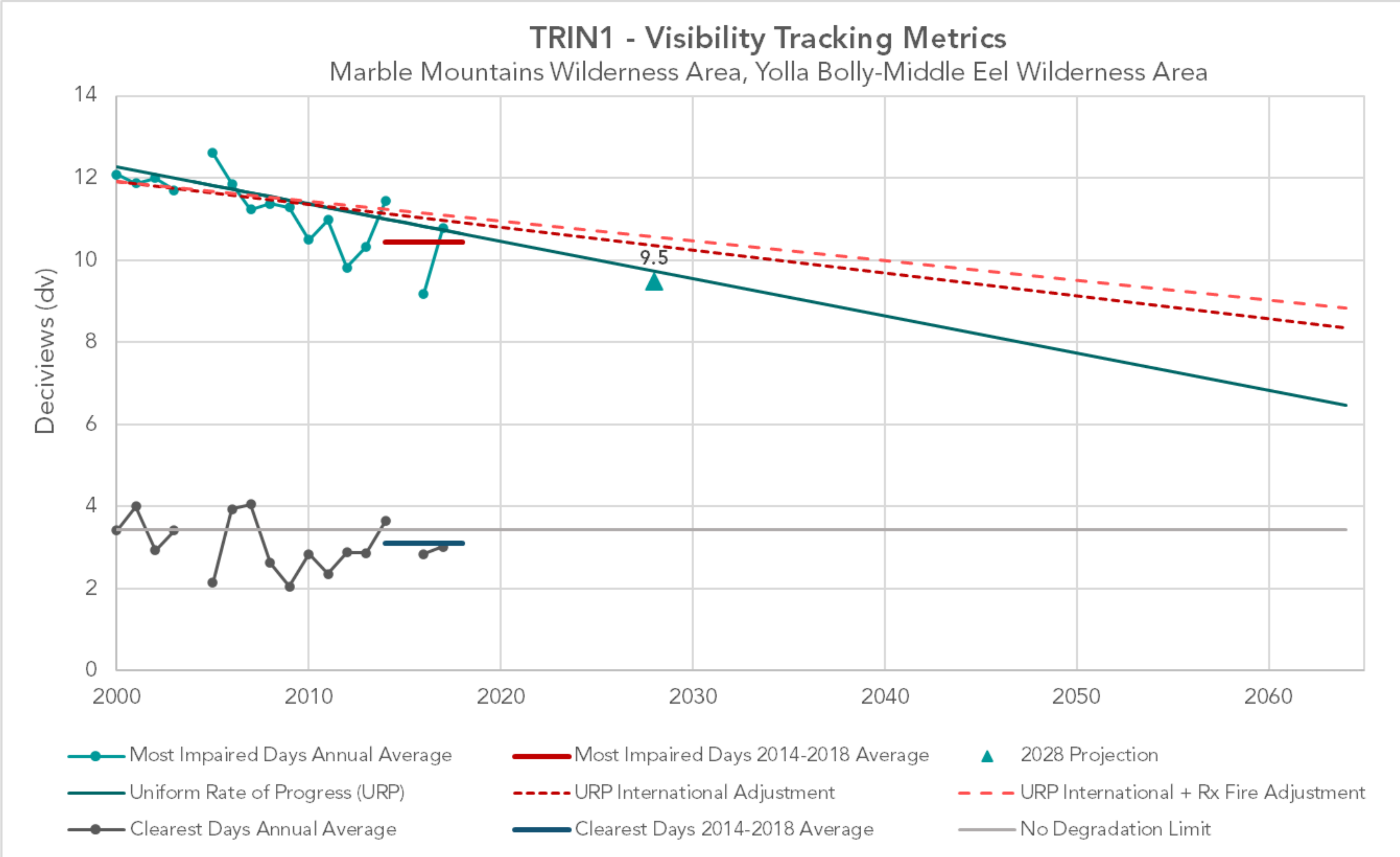
As shown in Figure C-23, California emissions account for the largest portion of light extinction from ammonium sulfate attributable to regional emissions. Note that, however, the projected portion of light extinction from ammonium sulfate is a fraction of light extinction attributable to ammonium nitrate in 2028.

Figure C-24: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at TRIN1



The current and projected trends for the visibility tracking metrics in the Marble Mountains and the Yolla Bolly-Middle Eel Wilderness Areas are shown in Figure C-25. Accounting for the adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 9.5 dv in 2028, which is equivalent to a visual range of 94 miles (151 km). The 2028 projection is below the adjusted glidepath, which accounts for international and wildland prescribed fire emissions, indicating these areas are on track to meet 2064 visibility targets.

Figure C-25: Visibility Tracking Metrics and Projections for the Marble Mountains and Yolla Bolly-Middle Eel Wilderness Areas



Lassen Volcanic National Park (LAVO1) IMPROVE Monitoring Site

The LAVO1 monitoring site, shown below in Figure C-26, is in the northwest portion of Lassen Volcanic National Park at 5,682 feet (1732 m) asl, adjacent to the ranger station at the Manzanita Lake entrance and southeast of the fire station. Park amenities are concentrated in the Manzanita Lake area including a large, developed campground with 125 sites and camping cabins. Annual visitation during the current period was around 500,000 people.[6] The monitoring site was established in March 1988. Data collected at this site are representative of visibility conditions in the Caribou Wilderness Area, Lassen Volcanic National Park, and the Thousand Lakes Wilderness Area.

Figure C-26: Photograph looking north towards the LAVO1 monitoring site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

The Caribou Wilderness Area covers 19,080 acres of high elevation forested plateau. The landscape is dotted with numerous lakes. The Caribou Wilderness Area is just east of Lassen Volcanic National Park. Lassen Volcanic National Park spans 105,800 acres and includes eight different active hydrothermal areas, a variety of volcanic domes that include all four types of volcanoes, as well as numerous lakes and streams. North of Lassen Volcanic National Park, the Thousand Lakes Wilderness Area spans 15,695 acres. The landscape in the Thousand

[6] *https://irma.nps.gov/STATS/Reports/Park/LAVO*

Lakes Wilderness Area is characterized by volcanic peaks, glacial carved valleys, a handful of high elevation lakes, and dense stands of fir and pine trees.

The Thousand Lakes Wilderness Area and the majority of Lassen Volcanic National Park are within the Sacramento Valley Air Basin. The LAVO1 monitoring site is also within the Sacramento Valley Air Basin. The northeast portion of Lassen Volcanic National Park and the majority of the Caribou Wilderness Area are in the Northeast Plateau Air Basin. The southeastern edge of Lassen Volcanic National Park and southern edge of the Caribou Wilderness Area are in the Mountain Counties Air Basin.

As shown in Table C-4, visibility impairment on the clearest days during the baseline period was 2.7 dv. Visibility impairment on the clearest days decreased by 0.5 dv between the baseline and the current periods. During the current period, visibility impairment was 2.2 dv, which is equivalent to a visual range of 194 miles (313 km).

Visibility impairment on the most impaired days during the baseline period was 11.5 dv. Visibility impairment decreased by 1.3 dv between the baseline and current periods. During the current period visibility impairment was 10.2 dv, which is equivalent to a visual range of 87 miles (141 km). Between the baseline and current periods, visibility improved by an average of 0.09 dv per year. This rate of improvement is greater than the URP adjusted to account for international emissions and prescribed fire.

Table C-4: Visibility Tracking Metrics for LAVO1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	2.7	2.2	1.0	0.5 dv	1.2 dv	--	--
Most Impaired	11.5	10.2	6.1	1.3 dv	4.1 dv	0.09 dv/year (0.06 dv/year)	0.09 dv/year

Monitoring data, shown in Figures C-27 and C-28, indicate that on the clearest and most impaired days ammonium sulfate and organic mass account for the largest portion of light extinction at the LAVO1 monitor. The low sulfur diesel regulations adopted in California between the baseline and current periods have led to decreased sulfur emissions from mobile sources and subsequently decreased sulfate particles. Between the baseline monitoring and current periods, light extinction from ammonium sulfate decreased 20 percent on the clearest days and 23 percent on the most impaired days. Light extinction from organic mass decreased by 22 percent on the clearest and 6 percent most impaired days.

Figure C-27: Average Extinction Composition for LAVO1 on the Clearest Days

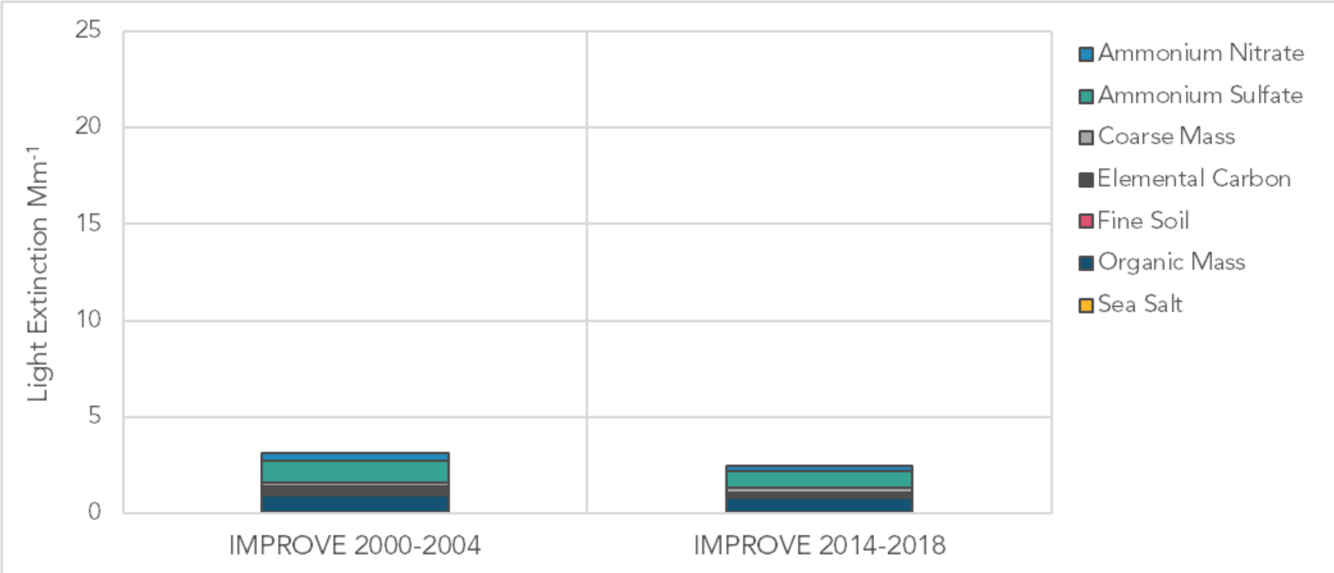
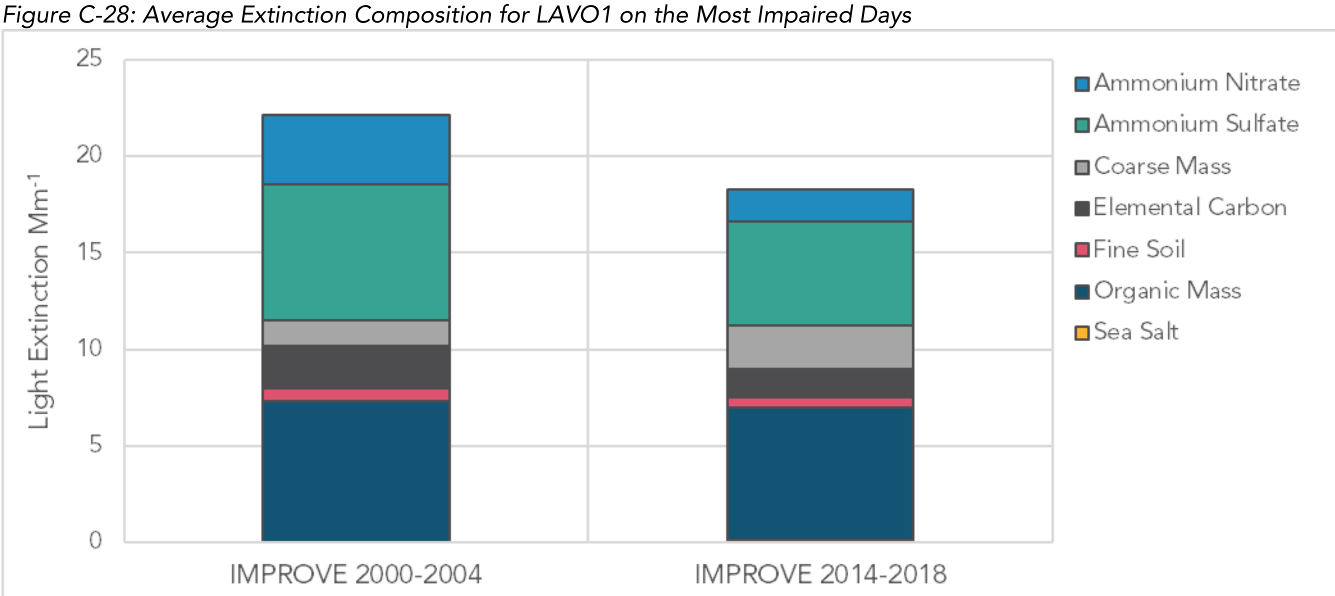
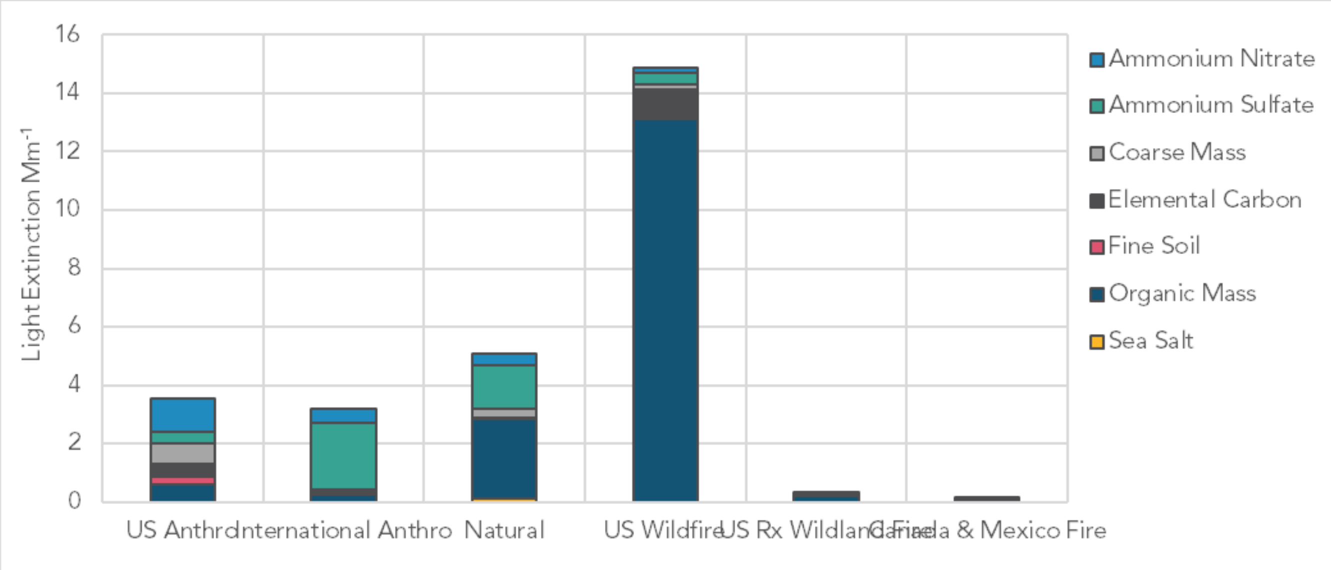


Figure C-28: Average Extinction Composition for LAVO1 on the Most Impaired Days



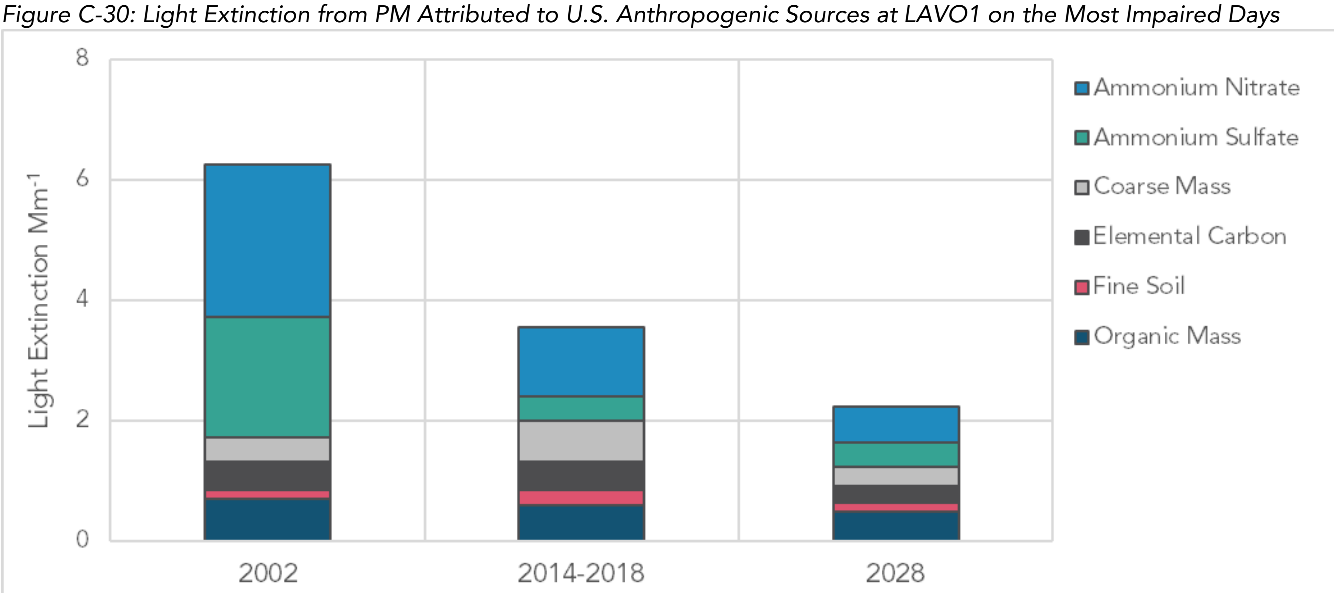
Source apportionment modeling, shown in Figure C-29, indicates that wildfires are the dominant source of visibility reducing particles measured at the LAVO1 monitoring site. Emissions from other natural, U.S., and international sources also contribute to visibility impairment on the most impaired days. Organic mass is primarily from wildfires and natural emission sources. Ammonium sulfate is primarily from international and natural sources.

Figure C-29: Source Apportionment Modeling Results for LAVO1 on the Most Impaired Days in 2014-2018



As shown in Figure C-30, the portion of light extinction attributed to U.S. sources is dominated by ammonium nitrate. Between the current period and 2028, emission controls are expected to reduce light extinction attributable to ammonium nitrate by 45 percent. Projections for 2028, indicate that ammonium nitrate will continue to account for the largest share of light extinction from U.S. sources.

Figure C-30: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at LAVO1 on the Most Impaired Days



Regional source apportionment, shown in Figures C-31 and C-32, indicates that California sources continue to be the largest regional sources of ammonium nitrate and ammonium sulfate in 2028. Light extinction attributable to ammonium nitrate is projected to be about twice the amount as that attributable to ammonium sulfate. Mobile sources in California will continue to be the dominant source of ammonium nitrate.

Figure C-31: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at LAVO1

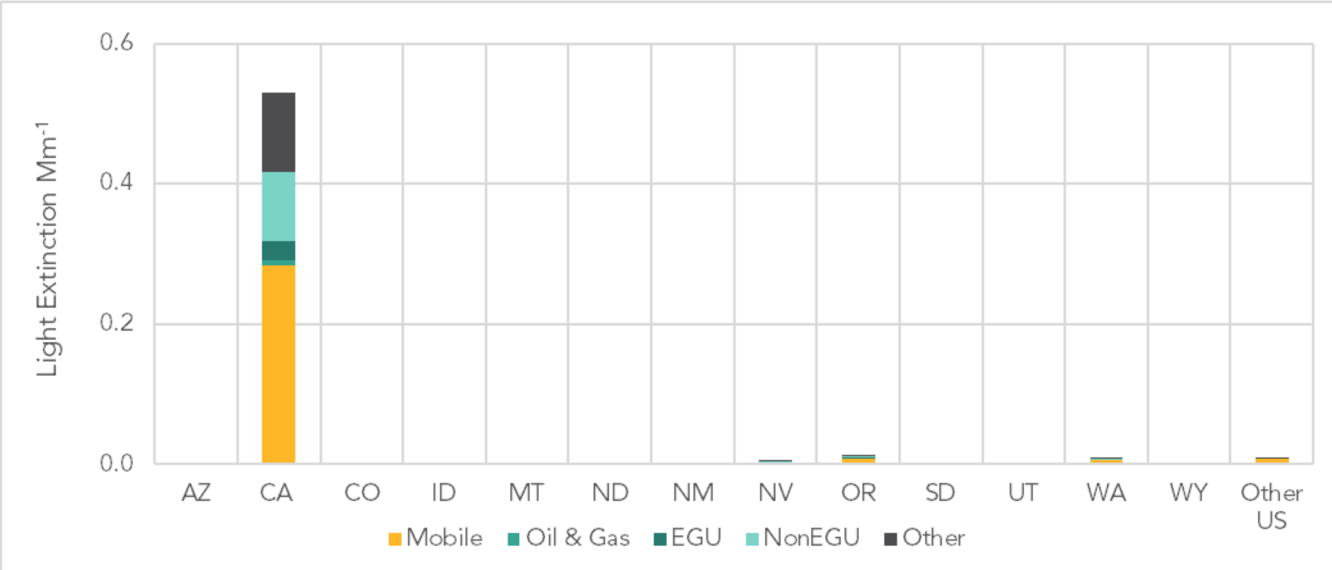
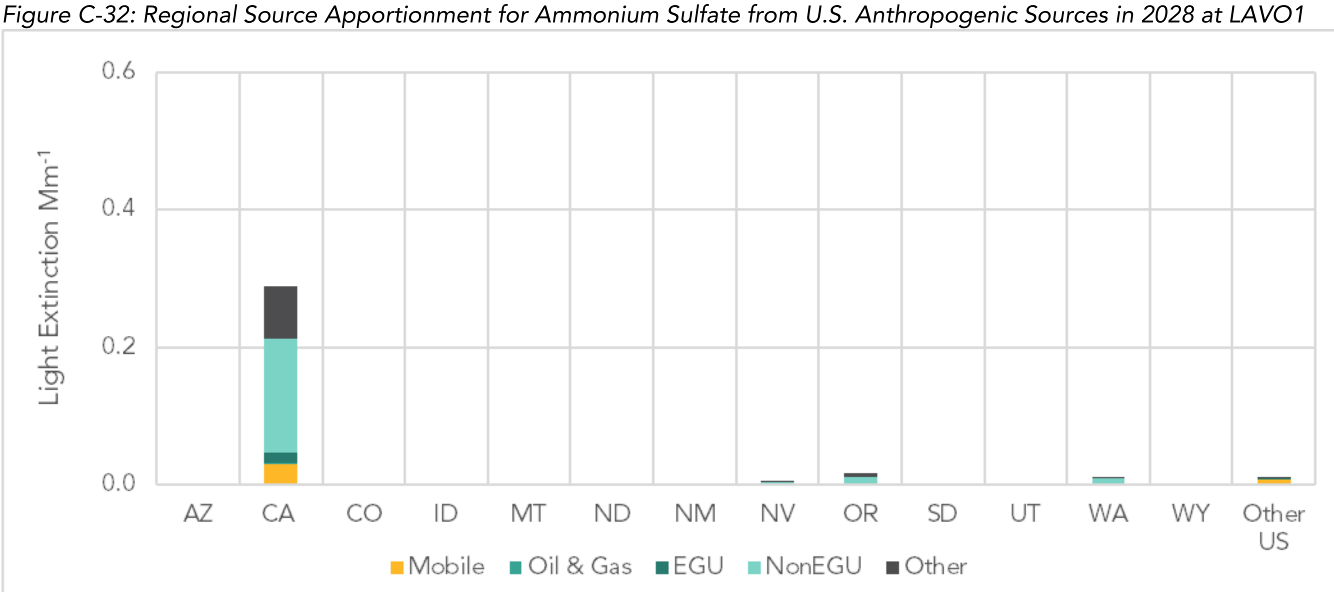


Figure C-32: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at LAVO1

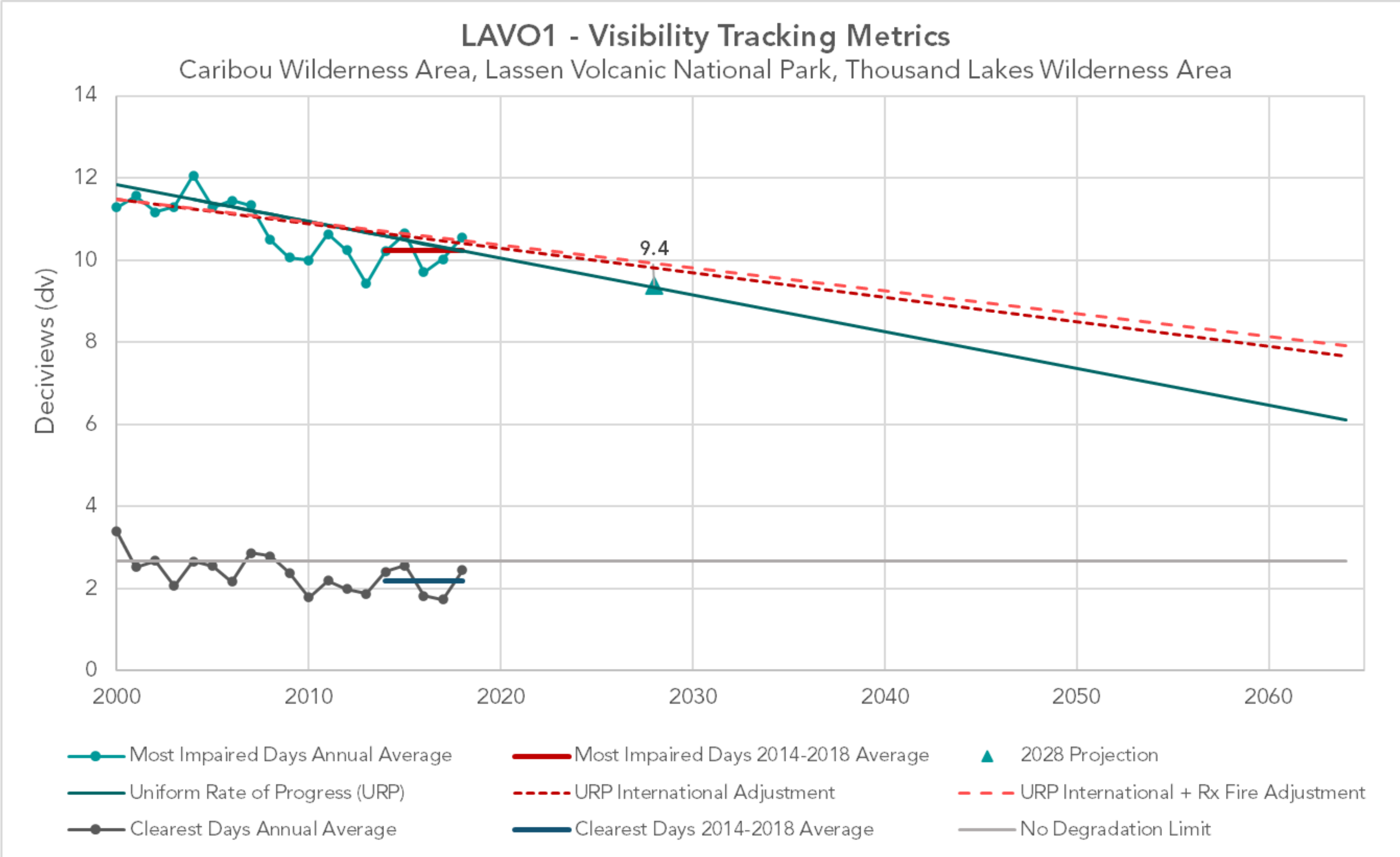


California's long-term strategy for regional haze is focused on improving visibility through reduction of NOx emissions from mobile sources. This strategy is expected to lead to improved visibility in the Caribou Wilderness Area, Lassen Volcanic National Park, and the Thousand Lakes Wilderness Area.

The current and projected trends for visibility tracking metrics for the Caribou Wilderness Area, Lassen Volcanic National Park, and the Thousand Lakes Wilderness Area are shown in

Figure C-33. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 9.4 dv in 2028, which corresponds to a visual range of 95 miles (152 km). This 2028 projection is below the adjusted glidepath, which accounts for international and wildland prescribed fire emissions, indicating that these areas are on track to meet 2064 visibility targets.

Figure C-33: Visibility Tracking Metrics and Projections for Caribou Wilderness Area, Lassen Volcanic National Park, and Thousand Lakes Wilderness Area



DL Bliss State Park (BLIS1) IMPROVE Monitoring Site

The BLIS1 monitoring site, shown below in Figure C-34, is located at DL Bliss State Park at 6,991 feet (2,131 m) asl on a service road near the southwest shore of Lake Tahoe and park headquarters. The monitoring site is within the Lake Tahoe Air Basin, northeast of the Desolation Wilderness Area. The monitoring site was established in November 1990. Data collected at this site are intended to be representative of visibility conditions in the Desolation and Mokelumne Wilderness Areas. Local emission sources including campground operations at DL Bliss State Park, residential wood combustion from communities within the Lake Tahoe Air Basin, and mobile sources operating within the Lake Tahoe Air Basin likely contribute to PM collected at the BLIS1 monitor.

Figure C-34: Photograph looking northeast towards BLIS1 Monitoring Site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

The Desolation Wilderness Area spans 63,469 acres and the Mokelumne Wilderness Area covers 50,400 acres. These Wilderness Areas encompass vast expanses of rugged, high elevation mountainous terrain that include sub-alpine and alpine forests replete with granite peaks and glacially formed valleys. The Desolation Wilderness Area is located west of Lake Tahoe and north of U.S. Highway 50 whereas the Mokelumne Wilderness Area is located south of Lake Tahoe. The Desolation Wilderness Area straddles the border of the Lake Tahoe and Mountain Counties Air Basins. The Mokelumne Wilderness Area lies along the border of the Mountain Counties Air Basin and the Great Basin Valleys Air Basin. Campfires and charcoal are prohibited throughout the Desolation Wilderness Area and travel is restricted to foot or horseback only. Campfires are permitted in certain areas of the Mokelumne Wilderness Area.

As shown in Table C-5, visibility impairment on the clearest days during the baseline period was 2.5 dv. Visibility impairment on the clearest days decreased by 0.7 dv between the baseline and the current periods. During the current period, visibility impairment was 1.8 dv, which corresponds to a visual range of 202 miles (326 km).

Visibility impairment on the most impaired days during the baseline period was 10.1 dv. Visibility impairment decreased by 0.8 dv between the baseline and current periods. During the current period, visibility impairment was 9.3 dv, which is equivalent to a visual range of 96 miles (154 km). Between the baseline and current periods, visibility improved by an average of 0.06 dv each year, which is equivalent to the URP adjusted to account for prescribed fire and international emissions.

Table C-5: Visibility Tracking Metrics for BLIS1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	2.5	1.8	0.4	0.7 dv	1.4 dv	--	--
Most Impaired	10.1	9.3	4.9	0.8 dv	4.4 dv	0.09 dv/year (0.06 dv/year)	0.06 dv/year

Monitoring data, shown in Figures C-35 and C-36, indicate that on the clearest and most impaired days, organic mass and ammonium sulfate have the most dominant impact on light extinction at the BLIS1 monitor. Between the baseline and the current periods, light extinction from organic mass decreased by 12 percent on the clearest days but increased by 3 percent on the most impaired days. This observed increase is likely indicative of the ongoing and significant contribution that fire emissions make to visibility impairment in these areas. Light extinction from ammonium sulfate decreased by 28 percent on the clearest days and by 17 percent on the most impaired days.

Figure C-35: Average Extinction Composition for BLIS1 on the Clearest Days

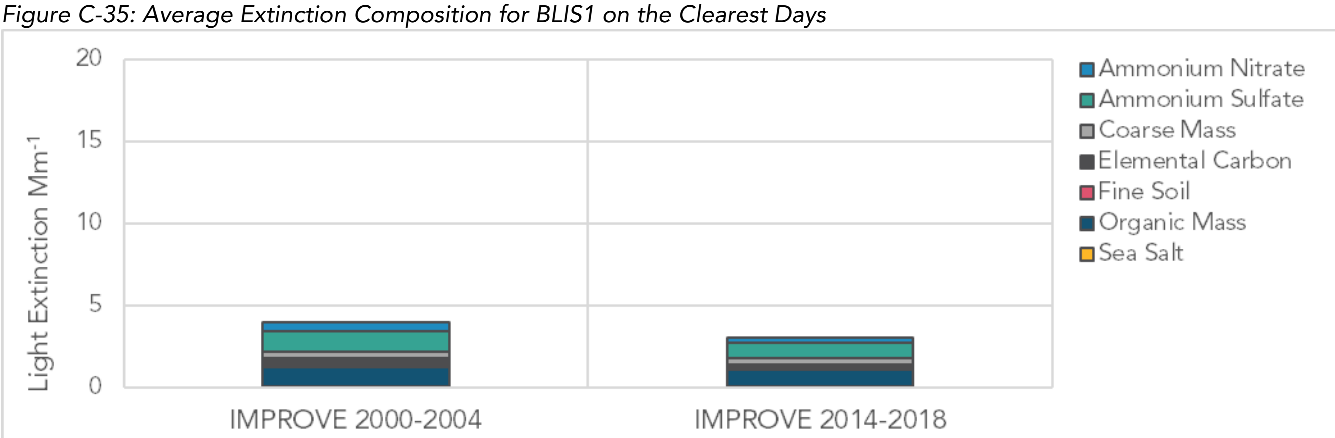
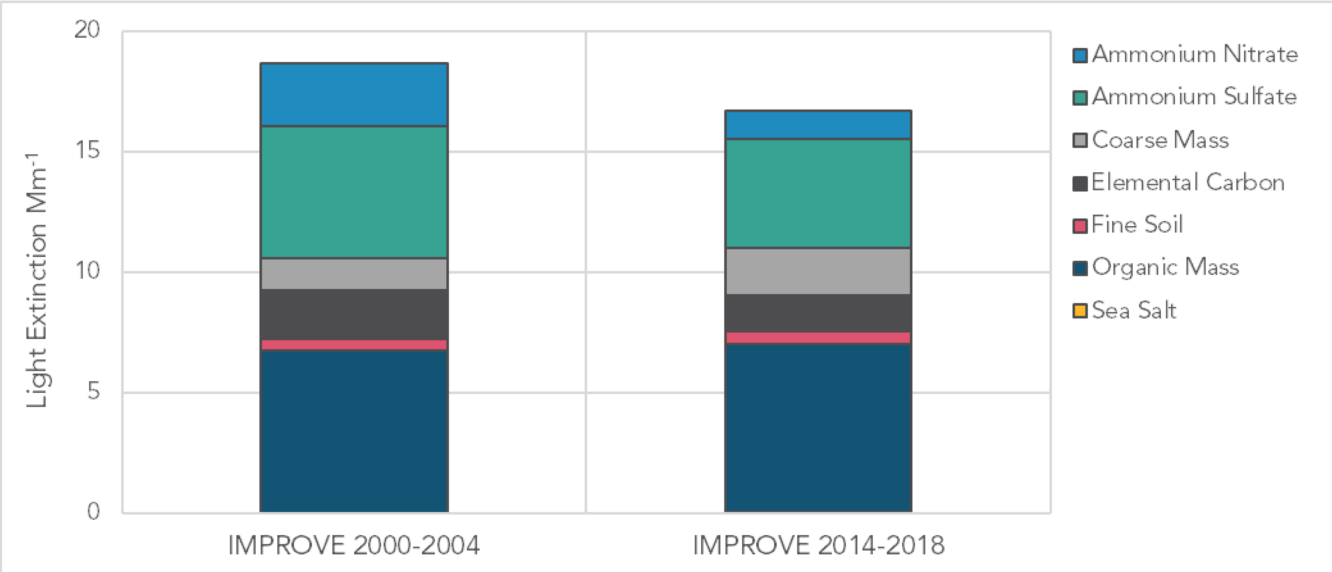
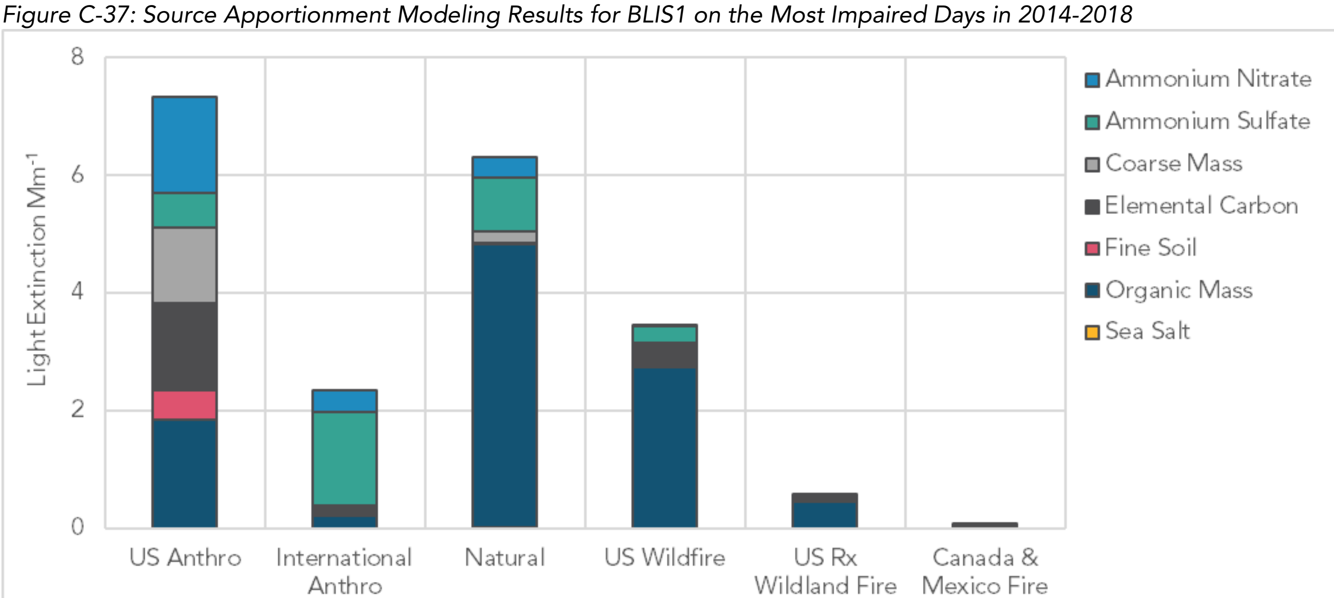


Figure C-36: Average Extinction Composition for BLIS1 on the Most Impaired Days



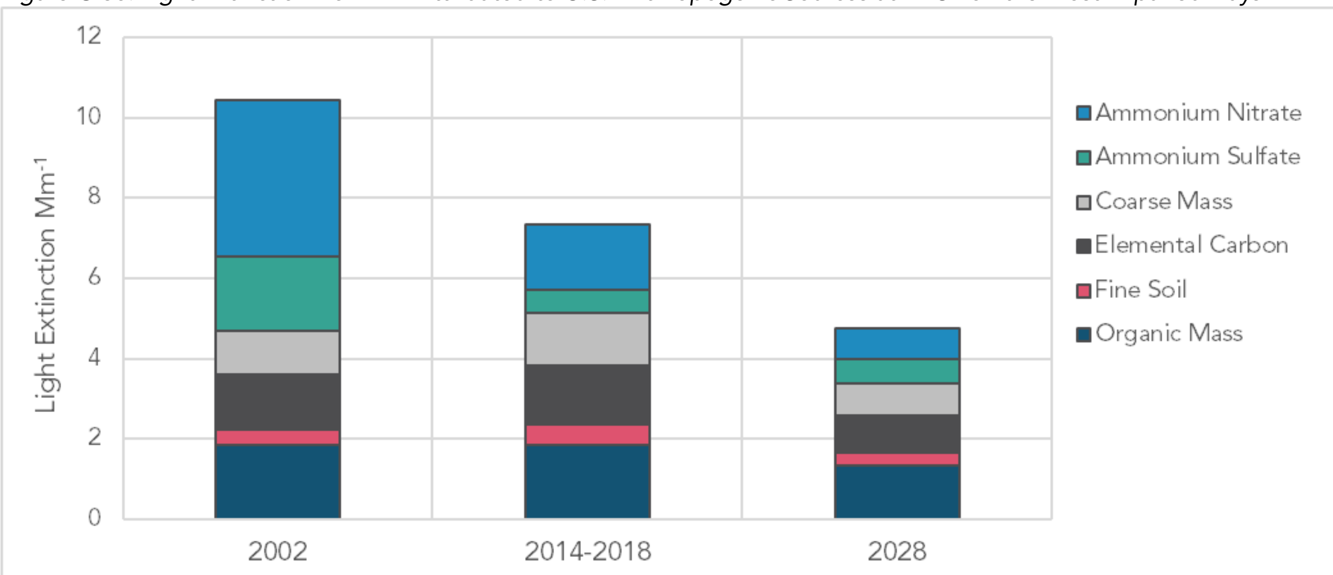
Source apportionment modeling, shown in Figure C-37, indicates that a combination U.S., natural, fire, and international emissions contribute to light extinction on the most impaired days at the BLIS1 monitoring site. This combination of sources underscores that sites throughout the western mountain ranges are ideally positioned to intercept emissions from a wide-array of sources and that, while highly resolved photochemically modeling in areas of complex terrain is a tall task, continued efforts to improve models and measurements will be needed to craft effective strategies as we move through the iterative planning periods and close in on the 2064 targets.

Figure C-37: Source Apportionment Modeling Results for BLIS1 on the Most Impaired Days in 2014-2018



As shown in Figure C-38, the portion of light extinction attributable to U.S. sources has generally been dominated by ammonium nitrate and organic mass. Moving from the current period into 2028, light extinction is attributable to a conglomerate of visibility impairing species. Organic mass, ammonium nitrate, coarse mass, and elemental carbon are shown to account for the largest portions of light extinction. Between the current period and 2028, projections show that light extinction from these sources is expected to decrease by 32 to 50 percent due to implementation of baseline (adopted) control measures. Ammonium sulfate and fine soil account for the smallest portion of the U.S. source light extinction contribution.

Figure C-38: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at BLIS1 on the Most Impaired Days



A high degree of uncertainty is associated with the modeling for coarse mass and lower level source apportionment for elemental carbon and organic mass was not feasible for this planning period. However, these are species typically associated with wood combustion. Emissions from local sources such as residential burning likely contribute to light extinction at this monitoring site. Future efforts to resolve sources of coarse mass, elemental carbon, and organic mass will improve our undertstanding of the emission sources impacting visibility in these areas.

The results of regional source apportionment modeling projections for ammonium nitrate and ammonium sulfate are shown in Figures C-39 and C-40, respectively. California emissions account for nearly all of the light extinction attributable to regional sources. Mobile sources make the largest contribution to light extinction attributable to ammonium nitrate. California's regional haze strategy is focused on reducing NOx emissions from mobile sources. This strategy is projected to benefit visibility conditions in the Desolation and Mokelumne Wilderness Areas.

Figure C-39: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at BLIS1

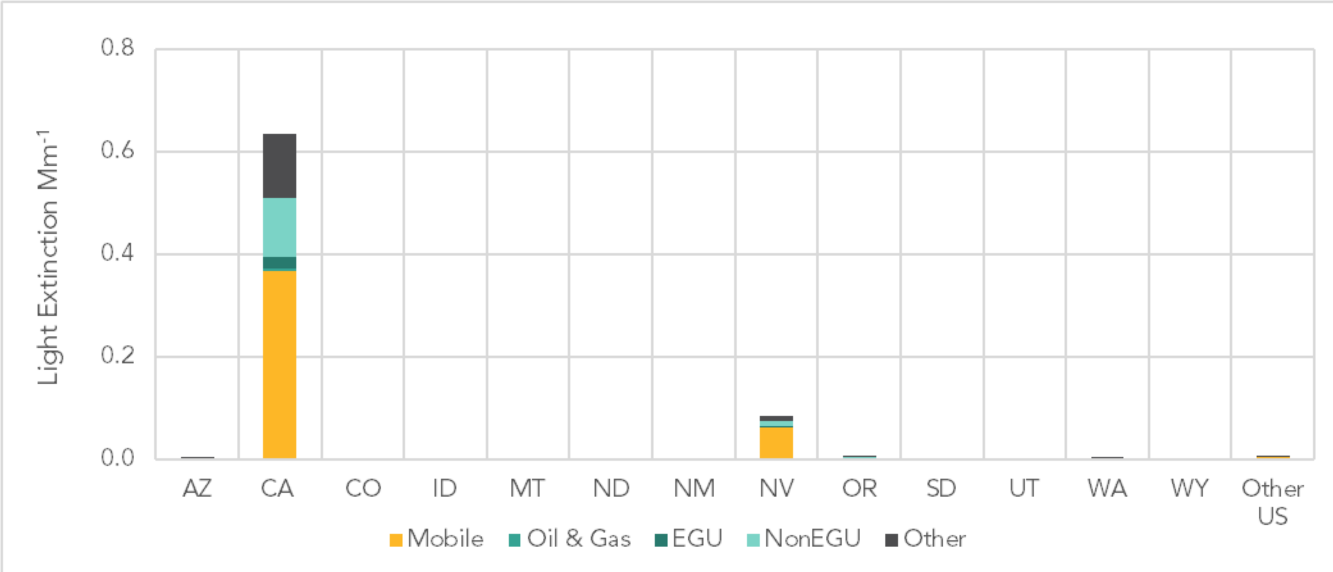
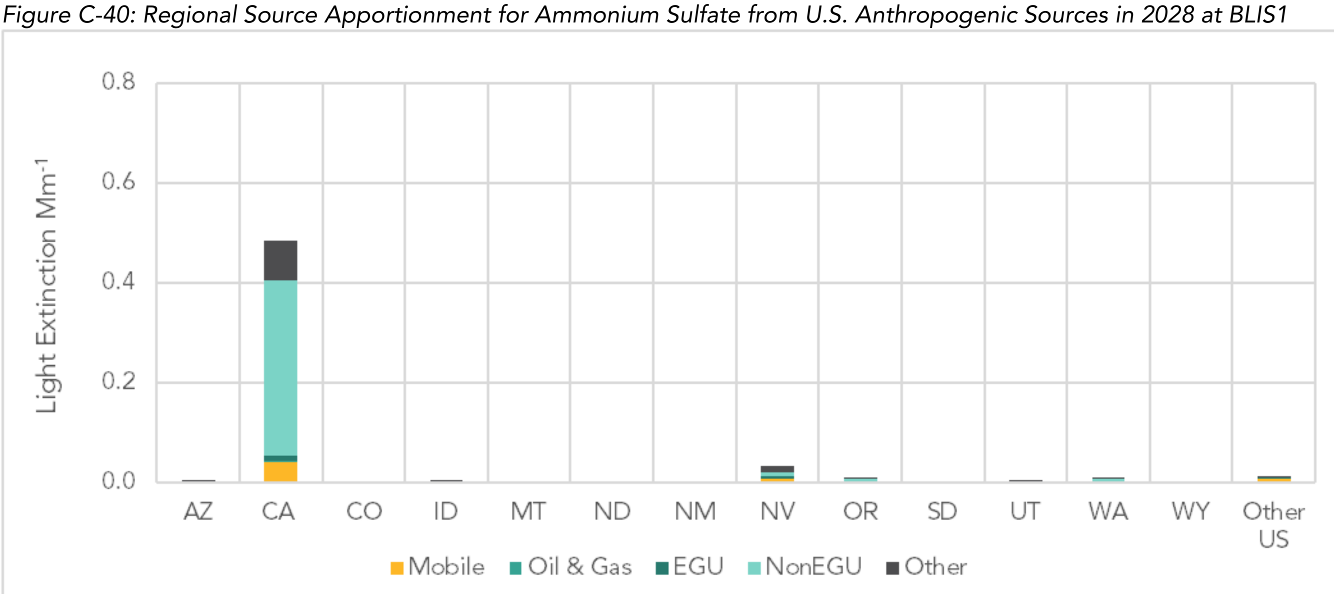
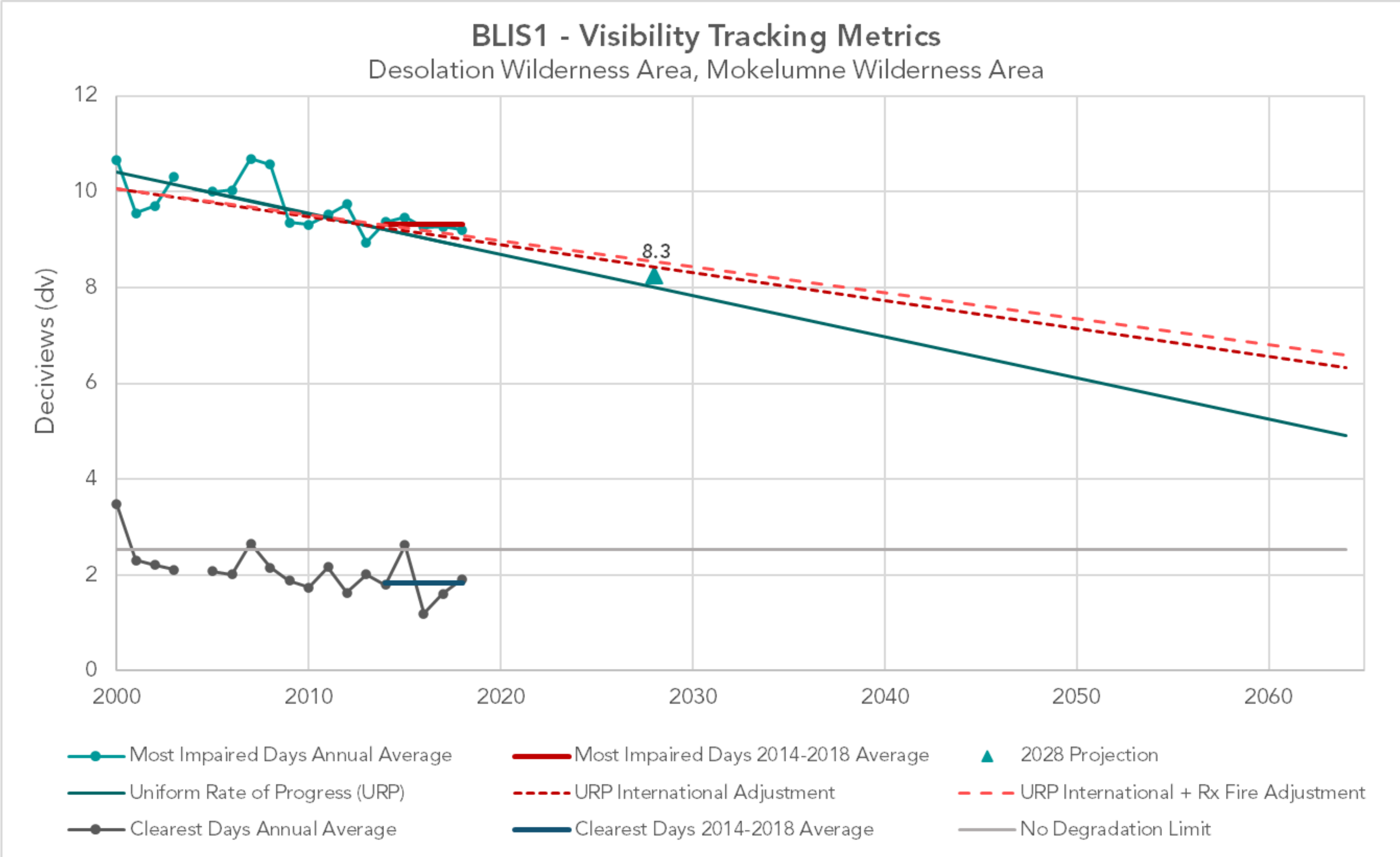


Figure C-40: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at BLIS1



The current and projected trends for visibility tracking metrics in the Desolation Wilderness Area and the Mokelumne Wilderness Area are shown in Figure C-41. Visibility impairment on the most impaired days is projected to be 8.3 dv in 2028, which represents a visual range of 106 miles (170 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating that these areas are on track to reach 2064 visibility targets.

Figure C-41: Visibility Tracking Metrics and Projections for Desolation and Mokelumne Wilderness Areas



Point Reyes National Seashore (PORE1) IMPROVE Monitoring Site

The PORE1 monitoring site, shown below in Figure C-42, is in the northwest portion of Point Reyes National Seashore at 318 feet (97 m) asl. The monitoring site was established in March 1988 adjacent to the North District Ranger Station. Data collected at this site are representative of visibility conditions at Point Reyes National Seashore.

Figure C-42: Photograph looking northeast toward the PORE1 monitoring site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

Point Reyes National Seashore spans 25,370 acres characterized by rocky headlands, open grasslands, and expansive sandy beaches. Annual visitation routinely exceeds two million people[7] due in part to the proximity to the densely populated San Francisco Bay Area. Point Reyes National Seashore is within the northwest corner of the San Francisco Bay Air Basin. Emissions from adjacent urban areas contribute to visibility impairment.

As shown in Table C-6, visibility impairment on the clearest days during the baseline period was 10.5 dv. Visibility impairment on the clearest days decreased by 2.3 dv between the baseline and current periods. During the current period, visibility impairment was 8.2 dv, which corresponds to a visual range of 107 miles (172 km).

Visibility impairment on the most impaired days during the baseline period was 19.4 dv. Visibility impaired decreased by 4.1 dv between the baseline and current periods. During the current period, visibility impairment was 15.3 dv, which is equivalent to a visual range of

[7] *https://irma.nps.gov/STATS/Reports/Park/PORE*

52 miles (84 km). The annual rate of improvement averaged 0.29 dv per year, which is faster than the URP and more than twice as fast as the adjusted URP.

Table C-6: Visibility Tracking Metrics for PORE1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	10.5	8.2	4.8	2.3 dv	3.4 dv	--	--
Most Impaired	19.4	15.3	9.7	4.1 dv	5.6 dv	0.16 dv/year (0.14 dv/year)	0.29 dv/year

Monitoring data, shown in Figures C-43 and C-44, indicate that ammonium sulfate accounts for the largest portion of light extinction on the clearest days and ammonium nitrate accounts for the largest portion of light extinction on the most impaired days at the PORE1 monitoring site. Like other coastal sites, natural oceanic emissions and offshore sources contribute to visibility impairment. California regulations to reduce emissions from ocean-going vessels and other mobile sources has had a measurable impact on visibility. Between the baseline monitoring period and the current period, light extinction from ammonium sulfate decreased by 47 percent on the clearest days while light extinction from ammonium nitrate decreased by 59 percent on the most impaired days.

Figure C-43: Average Extinction Composition for PORE1 on the Clearest Days

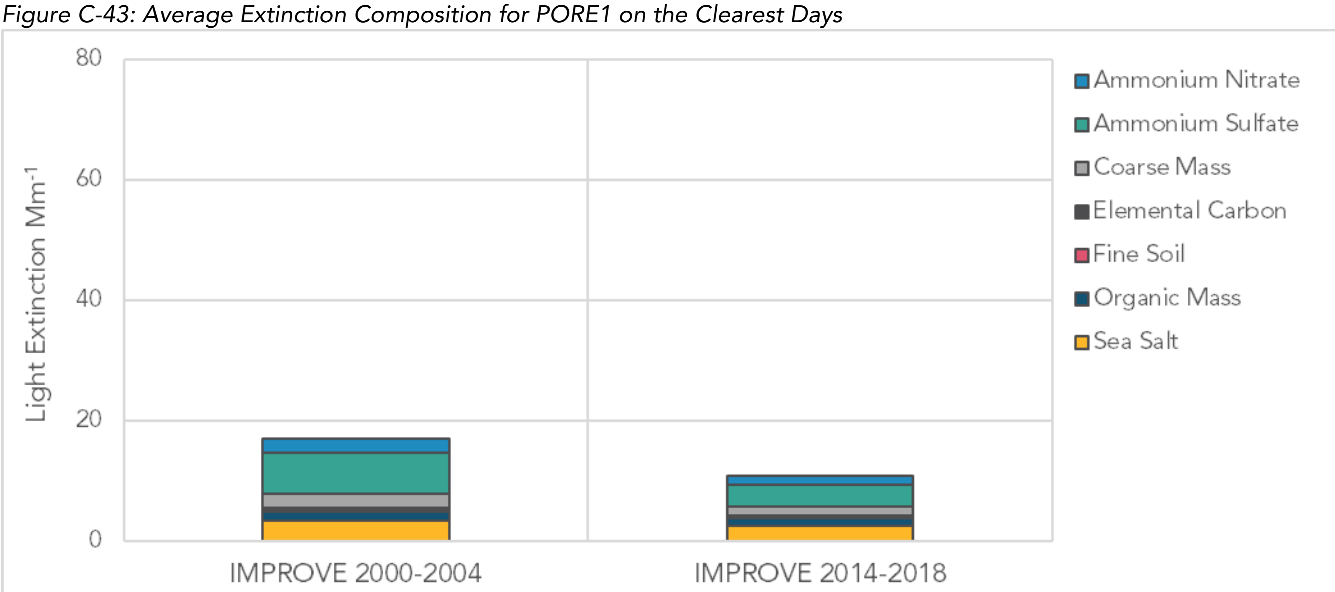
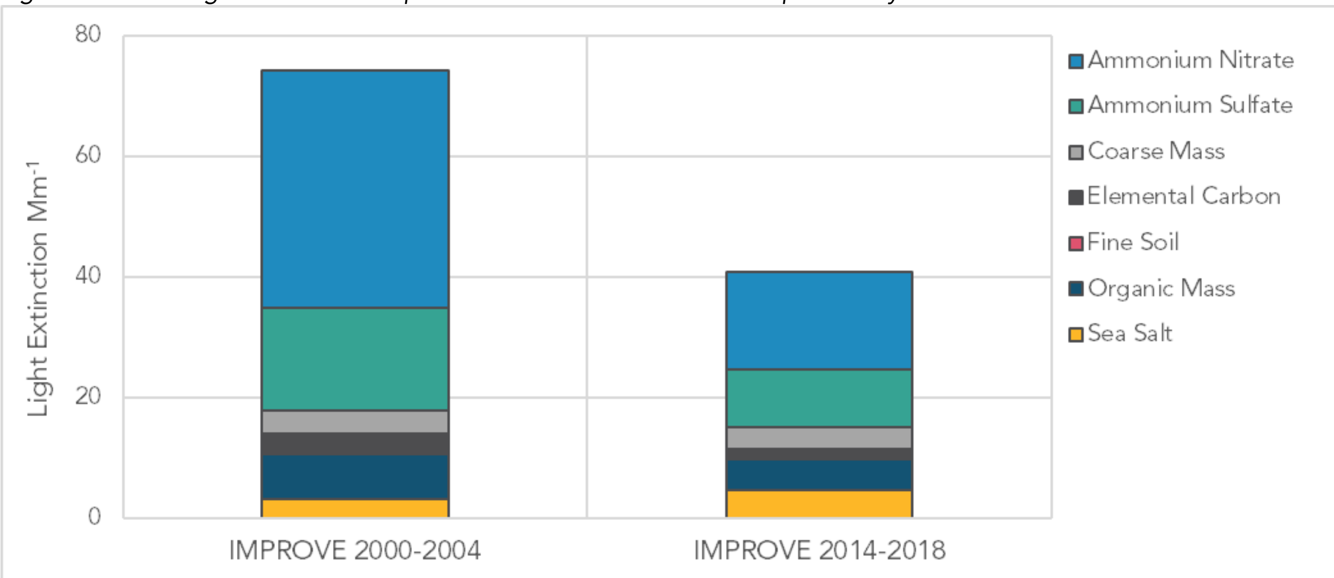
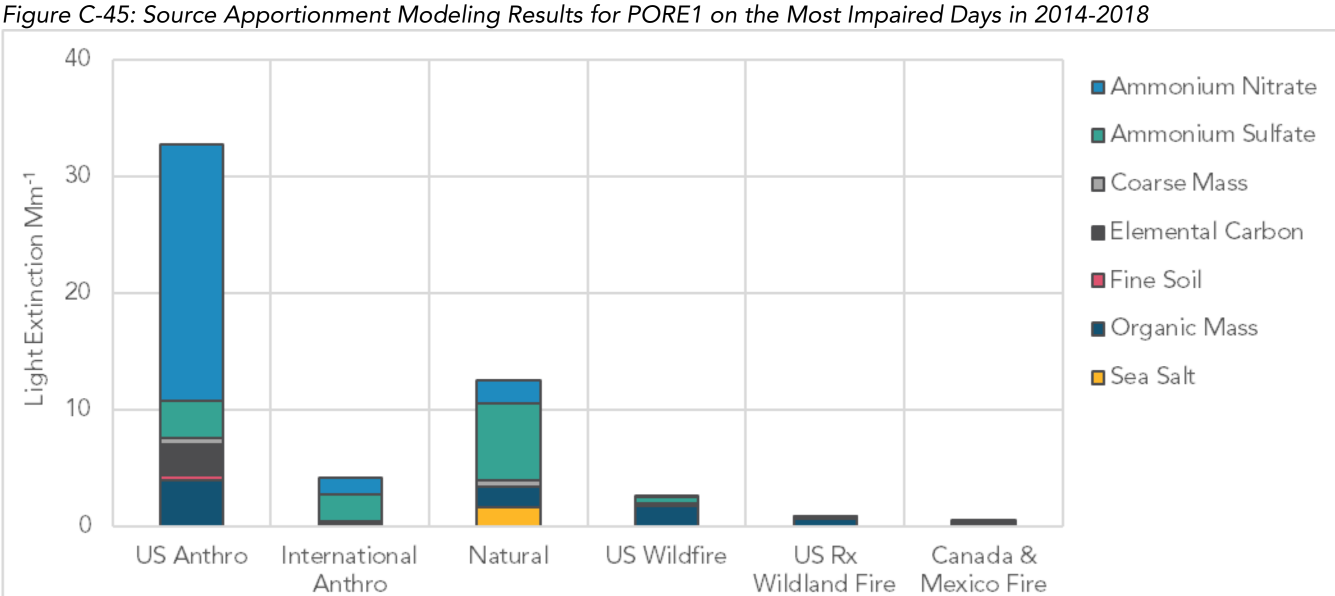


Figure C-44: Average Extinction Composition for PORE1 on the Most Impaired Days



Source apportionment modeling, shown in Figure C-45, indicates that U.S. emissions are the dominant source of visibility reducing particles measured at the PORE1 monitoring site. Emissions from natural sources, international sources, and fire also contribute to visibility impairment. Ammonium sulfate is the dominant PM species among those attributed to natural and international emissions. The portion of light extinction attributed to U.S. sources is dominated by ammonium nitrate.

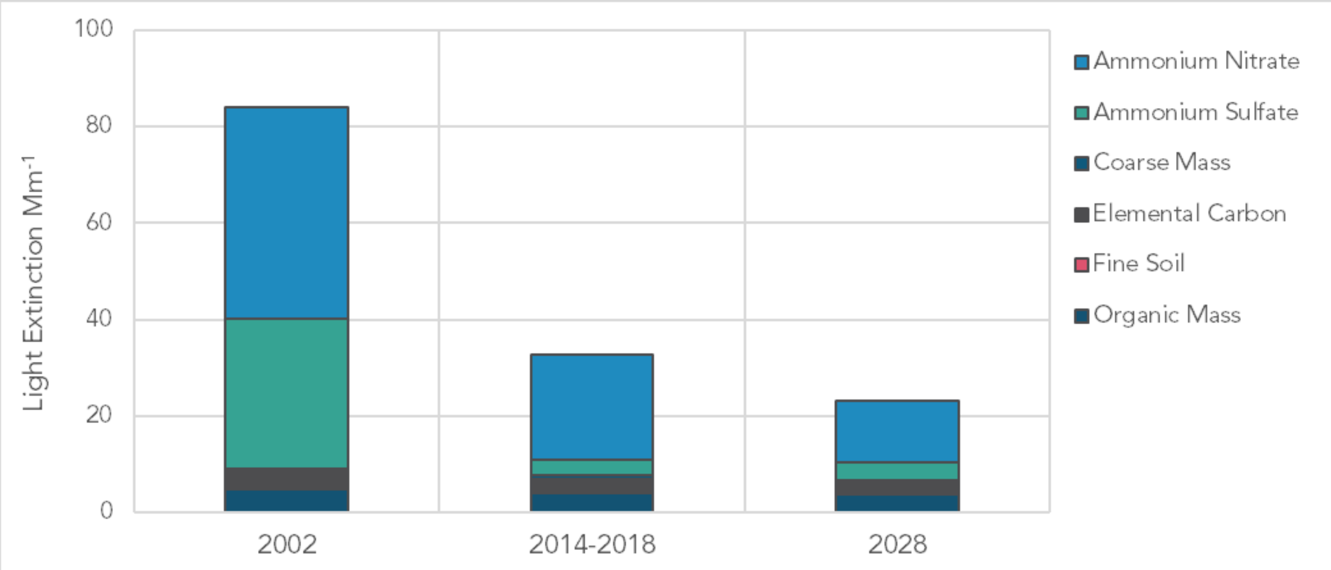
Figure C-45: Source Apportionment Modeling Results for PORE1 on the Most Impaired Days in 2014-2018



As shown in Figure C-46, between the current period and 2028, adopted emission controls are projected to reduce light extinction from the U.S. contribution to ammonium nitrate by

42 percent. However, ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. sources.

Figure C-46: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at PORE1 on the Most Impaired Days



The results of regional source apportionment for 2028 projections are shown in Figures C-47 and C-48. California mobile sources will continue to be the largest regional source of ammonium nitrate in 2028. Light extinction from ammonium sulfate attributable to regional sources is projected to be largely from stationary and area sources. However, the portion of light extinction from ammonium nitrate is more than three times greater than that from ammonium sulfate.

Figure C-47: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at PORE1

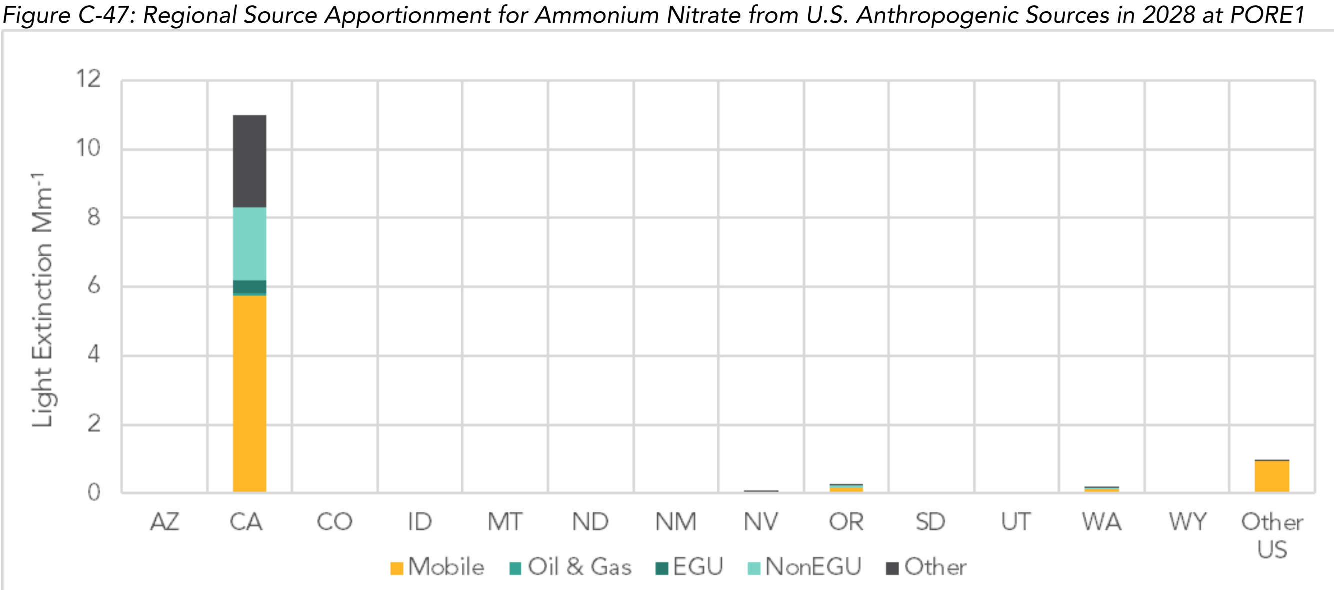
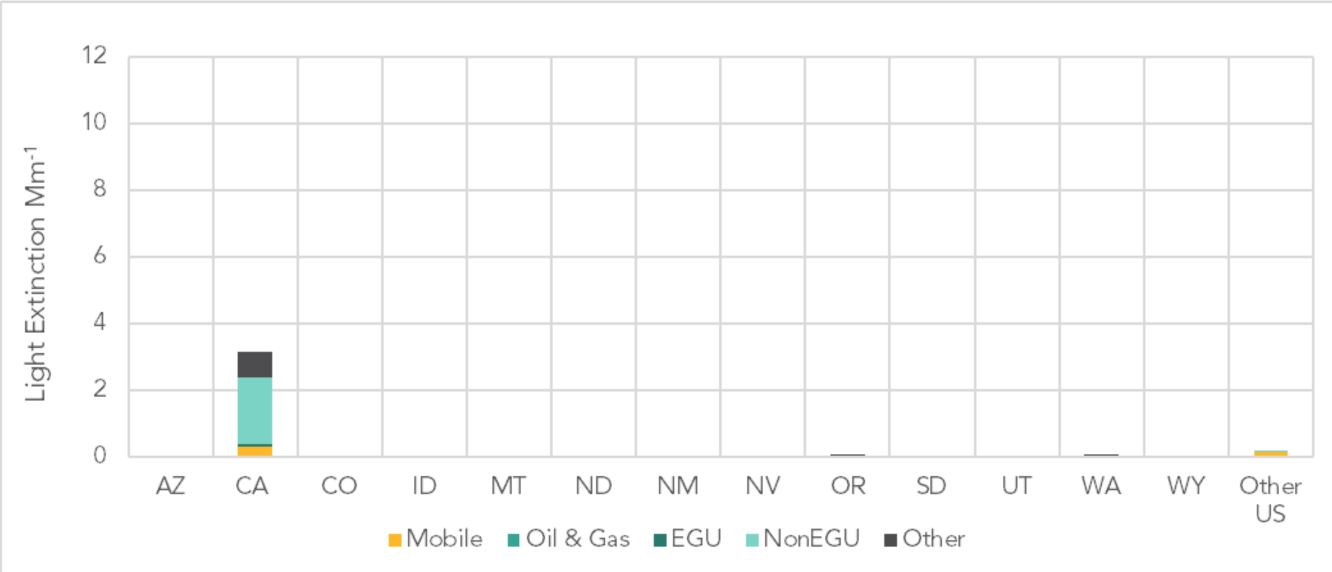


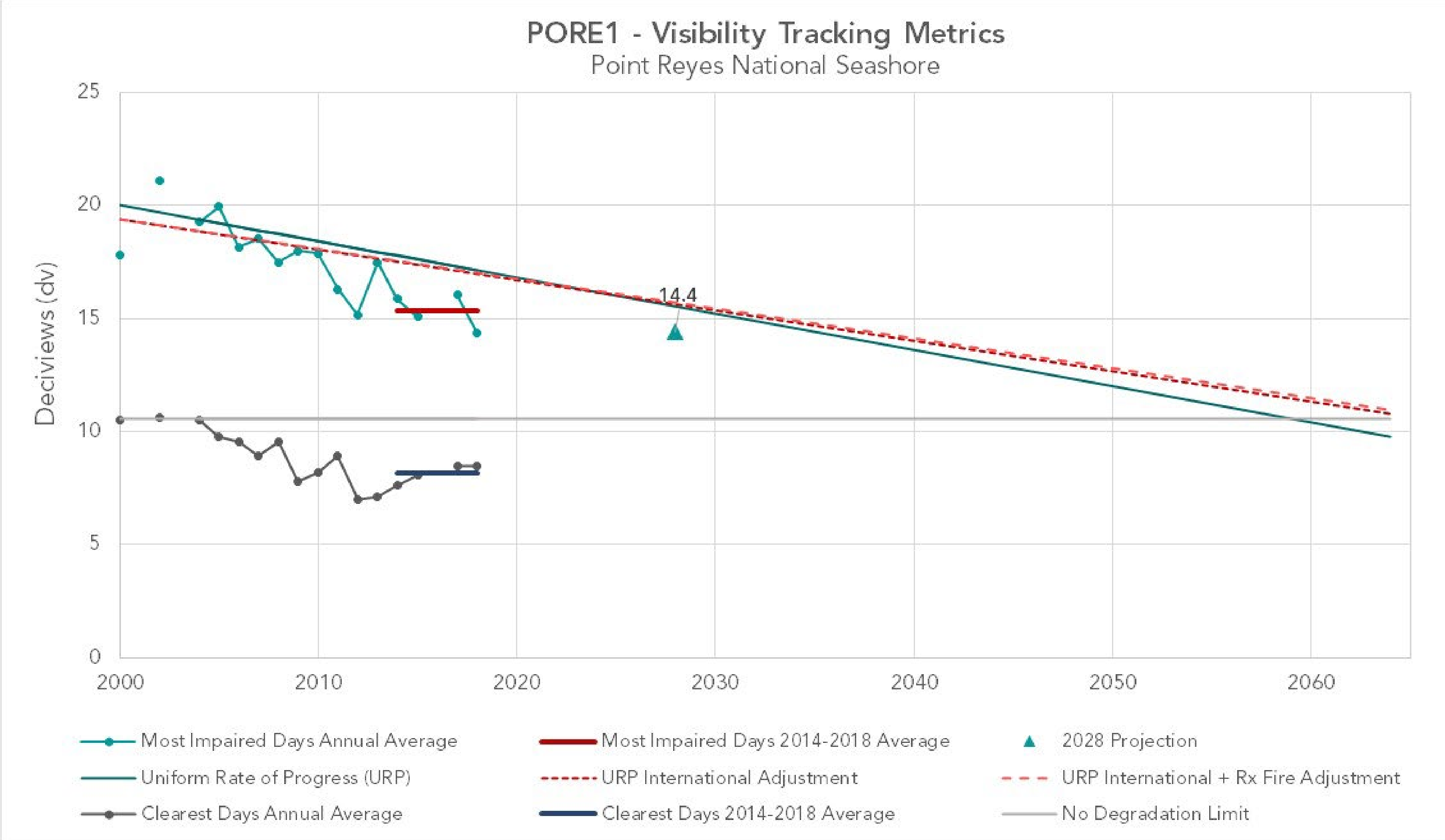
Figure C-48: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at PORE1



California's regional haze strategy is focused on reducing NOx emissions from mobile sources. Reducing NOx emissions, which generally drives the formation of ammonium nitrate in California, is projected to lead to a reduction in haze pollutants impacting visibility at Point Reyes National Seashore. Regional photochemical modeling analyses support this conclusion.

The current and projected trends for visibility tracking metrics at Point Reyes National Seashore are shown in Figure C-49. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 14.4 dv in 2028, which represents a visual range of 57 miles (92 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating that this area is on track to meet 2064 visibility targets.

Figure C-49: Visibility Tracking Metrics and Projections for Point Reyes National Seashore



Yosemite National Park (YOSE1) IMPROVE Monitoring Site

The YOSE1 monitoring site, shown in Figure C-50, is in the southwest portion of Yosemite National Park at 5,259 feet (1,603 m) asl. The monitoring site was established in March 1988 at Turtleback Dome, one mile west of Tunnel View. More than four million people visit the park annually, with nearly 800,000 visitors staying overnight in one of the thirteen campgrounds in either tents or RV campers. Concessioners operate multiple hotels, cabins, and tent cabins that host more than 600,000 visitors annually.[8] The heavy usage is promoted by Yosemite National Park's international acclaim and proximity to several urban areas. Data collected at the YOSE1 monitoring site are representative of visibility conditions in the Emigrant Wilderness Area and Yosemite National Park.

Figure C-50: Photograph of YOSE1 Monitoring Site

Photograph Source: https://www.nps.gov/yose/learn/nature/airquality.htm

The Emigrant Wilderness Area covers 104,311 acres. The Emigrant Wilderness Area is north of Yosemite National Park, which spans 759,172 acres. The landscape in the Emigrant Wilderness Area and Yosemite National Park is dramatic and features numerous granite peaks, glaciated granite basins and canyons, towering waterfalls, alpine meadows, and dense stands of evergreen trees. The Emigrant Wilderness Area, most of Yosemite National Park, and the YOSE1 monitor is within the Mountain Counties Air Basin. The southeastern edge of Yosemite National Park is within the San Joaquin Valley Air Basin.

As shown in Table C-7, visibility impairment on the clearest days during the baseline period was 3.4 dv. Visibility impairment on the clearest days decreased by 0.5 dv between the baseline and the current periods. During the current period, visibility impairment was 2.9 dv, which corresponds to a visual range of 181 miles (292 km).

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[8] *https://irma.nps.gov/STATS/Reports/Park/YOSE*

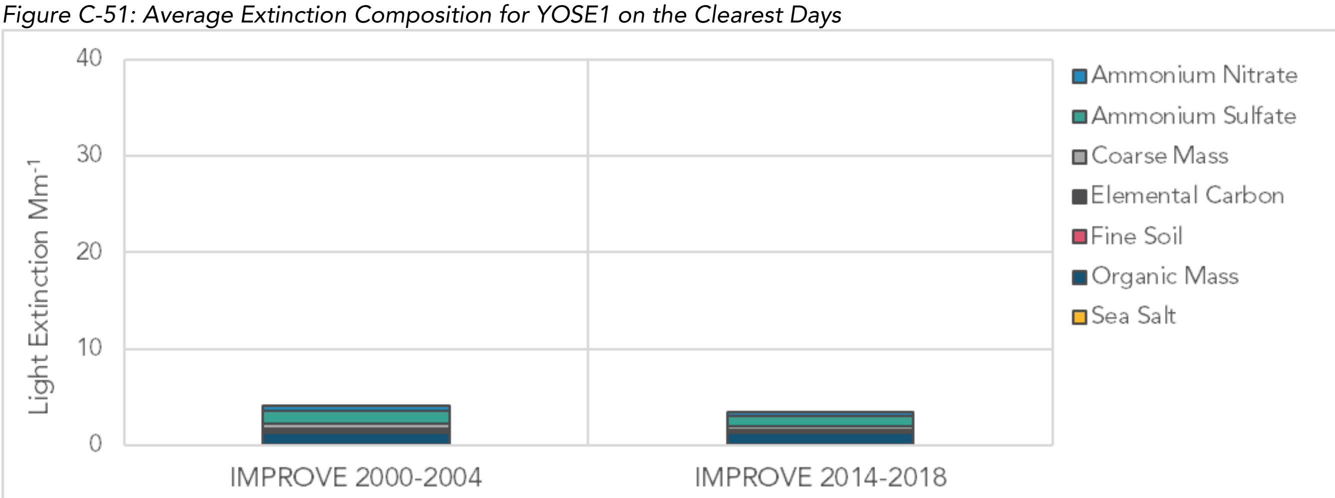
Visibility impairment on the most impaired days during the baseline period was 13.5 dv. Visibility impairment on the most impaired days decreased by 1.9 dv between the baseline and the current periods. During the current period, visibility impairment was 11.6 dv, which corresponds to a visual range of 76 miles (122 km). The average rate of progress between the baseline and current periods was 0.14 dv per year. This rate is greater than both the URP and the URP adjusted to account for international and prescribed fire emissions.

Table C-7: Visibility Tracking Metrics for YOSE1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	3.4	2.9	1.0	0.5 dv	1.9 dv	--	--
Most Impaired	13.5	11.6	6.3	1.9 dv	5.3 dv	0.12 dv/year (0.08 dv/year)	0.14 dv/year

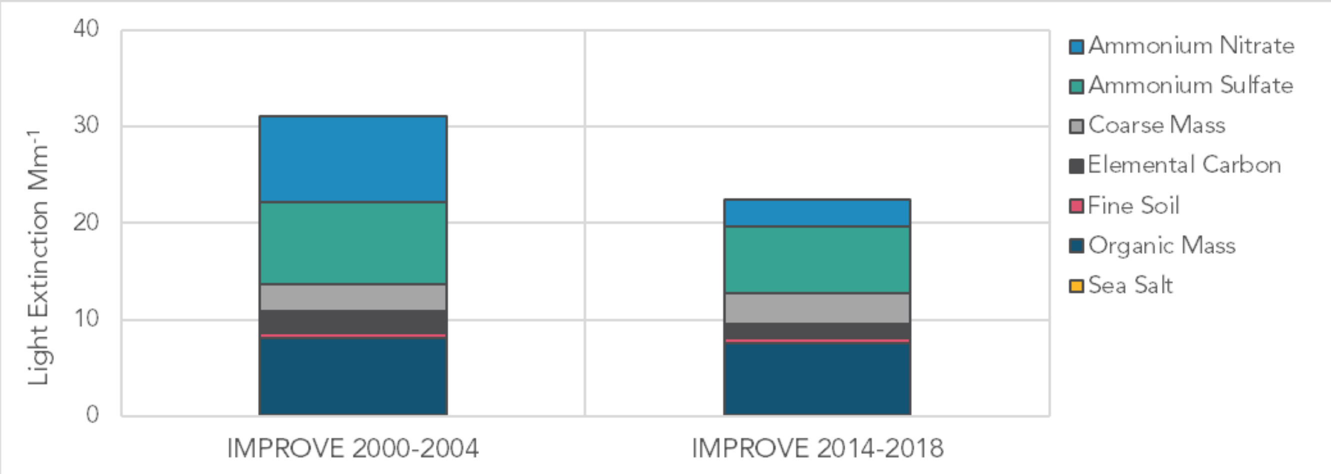
Monitoring data, shown in Figures C-51 and C-52, indicate that ammonium sulfate and organic mass have the most dominant impact on light extinction on the clearest days and the most impaired days.

Figure C-51: Average Extinction Composition for YOSE1 on the Clearest Days



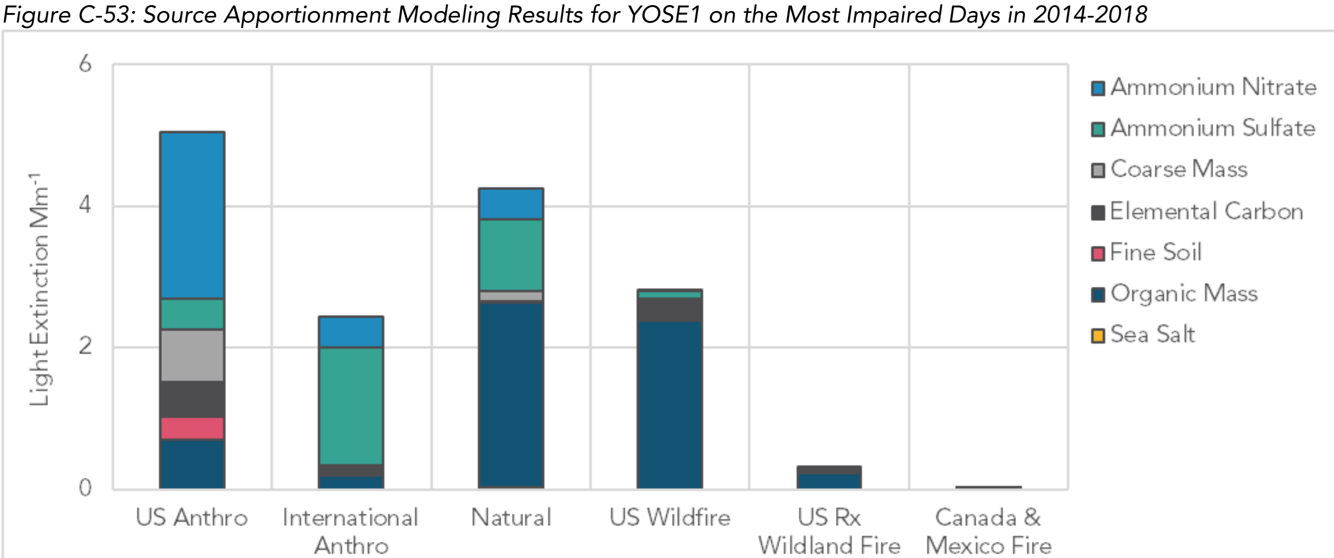
It is interesting to note that during the baseline monitoring period, ammonium nitrate accounted for the largest portion of light extinction on the most impaired days, closely followed by ammonium sulfate and organic mass. Between the baseline and current periods, light extinction from ammonium nitrate on the most impaired days decreased by 69 percent. Light extinction due to organic mass increased by four percent on the clearest days and decreased by seven percent on the most impaired days, whereas light extinction due to ammonium sulfate decreased by 26 percent on the clearest and 19 percent most impaired days.

Figure C-52: Average Extinction Composition for YOSE1 on the Most Impaired Days



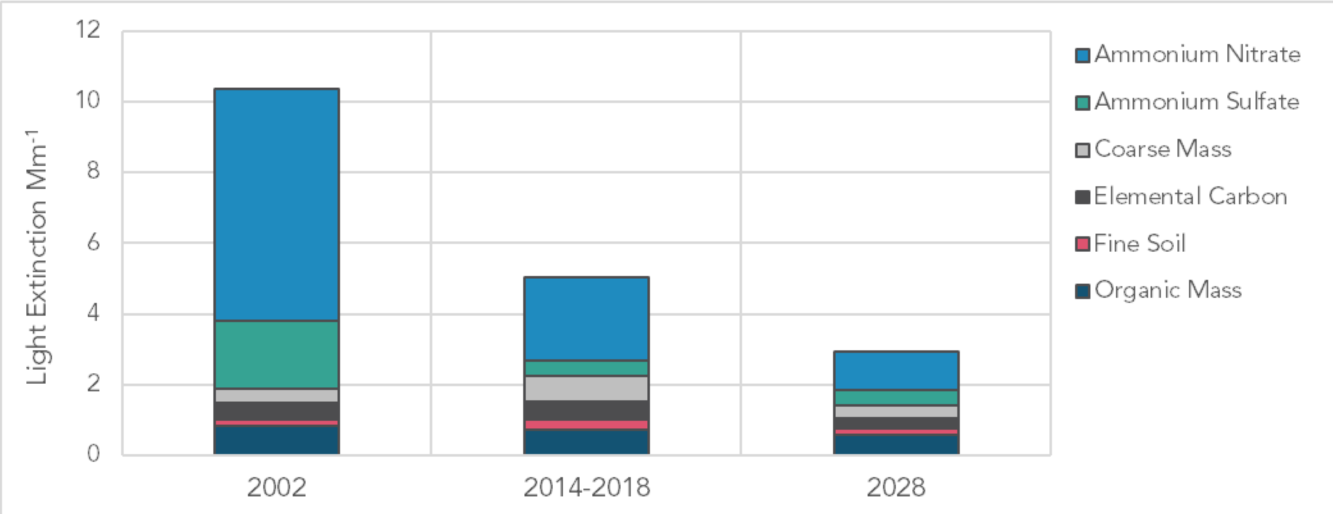
Source apportionment modeling, shown in Figure C-53, indicates that emissions from U.S. sources, natural sources, wildfires, and international sources contribute to visibility reducing particles measured at the YOSE1 monitoring site. Light extinction attributable to natural sources and wildfires is primarily due to organic mass, whereas light extinction attributable to international sources is largely due to ammonium sulfate. Ammonium nitrate is the dominant PM species attributable to U.S. sources contributing to light extinction.

Figure C-53: Source Apportionment Modeling Results for YOSE1 on the Most Impaired Days in 2014-2018



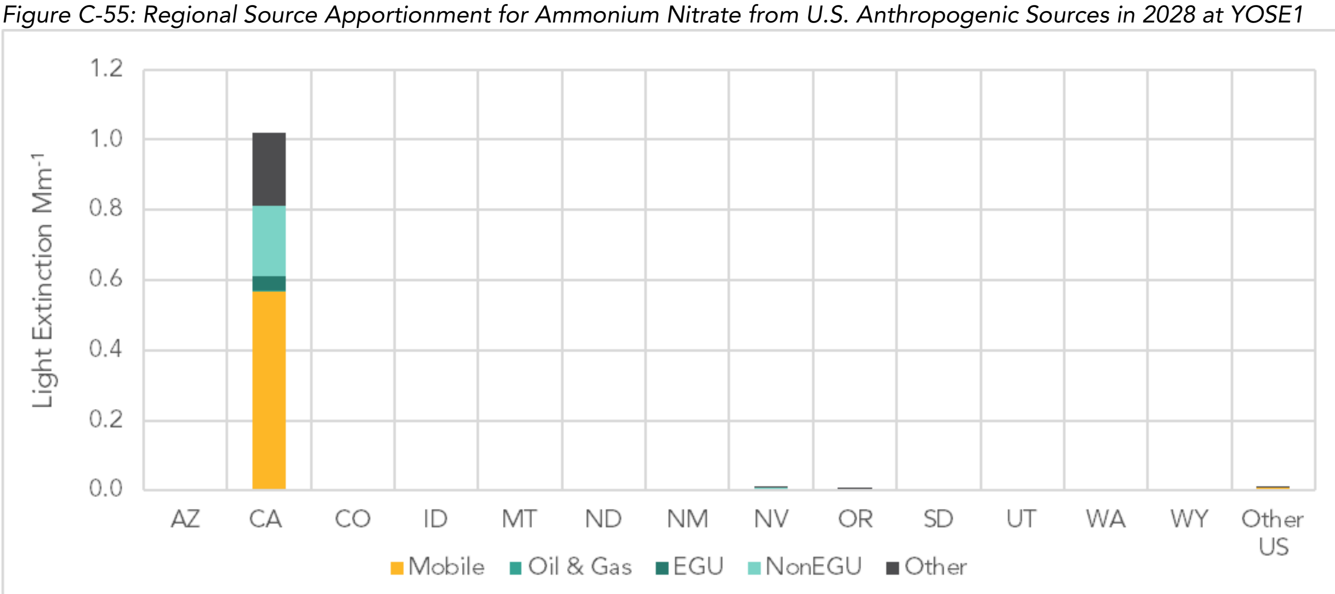
As shown in Figure C-54, emission reduction efforts have markedly reduced light extinction from ammonium nitrate and ammonium sulfate. Further reductions are expected. Between the current period and 2028, adopted emission controls are expected reduce light extinction from the U.S. sources contributing to ammonium nitrate by over 50 percent. Ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. emission sources in 2028.

Figure C-54: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at YOSE1 on the Most Impaired Days



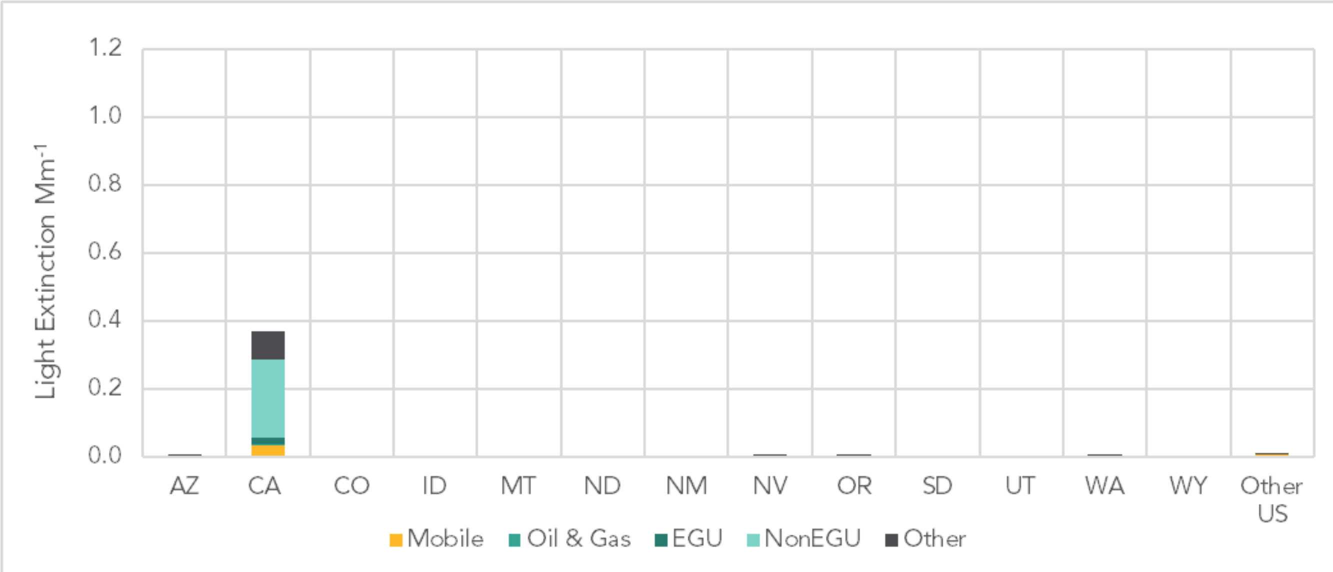
Regional source apportionment results are shown in Figures C-55 and C-56. The results indicate that California mobile sources will continue to be the largest regional source of ammonium nitrate in 2028, suggesting that continued efforts to reduce emissions from the mobile source sector will be an effective strategy to improve visibility in these areas.

Figure C-55: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at YOSE1



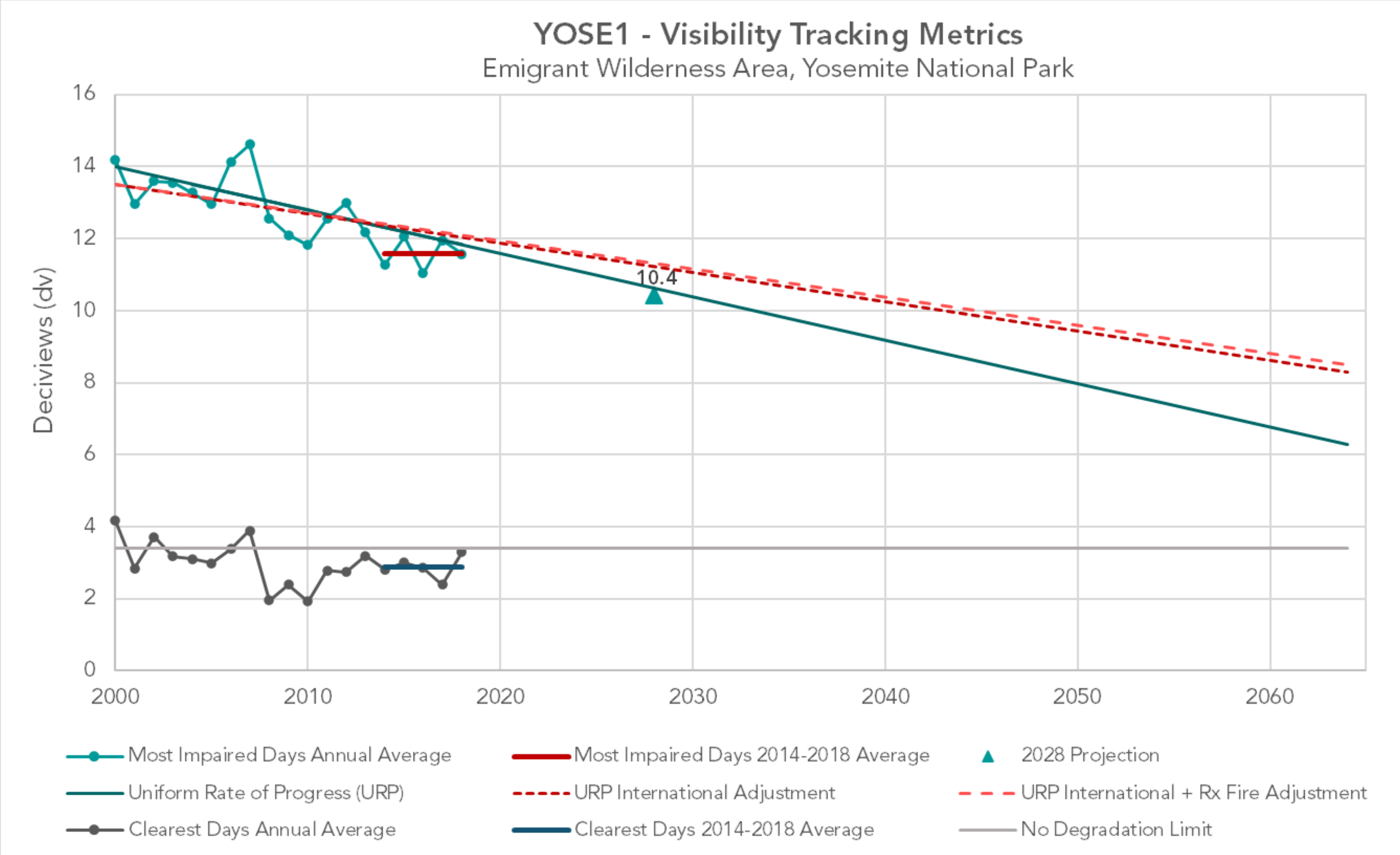
As shown in Figure C-56, California emissions account for the largest portion of light extinction from ammonium sulfate attributable regional anthropogenic emissions. The projected portion of light extinction from ammonium sulfate is less than half that from ammonium nitrate.

Figure C-56: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at YOSE1



The current and projected visibility tracking metrics for the Emigrant Wilderness Area and Yosemite National Park are shown in Figure C-57. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 10.4 dv in 2028, which is comparable to a visual range of 86 miles (138 km). This 2028 projection is below the adjusted glidepath that accounts for international emissions and wildland prescribed fire emissions, indicating that these areas are on track to meet 2064 visibility targets.

Figure C-57: Visibility Tracking Metrics and Projections for Emigrant Wilderness Area and Yosemite National Park



Central California

The population in the Central California region is concentrated around the cities of Stockton, Modesto, Fresno, and Bakersfield in the San Joaquin Valley Air Basin. These cities are hubs along one of California's busiest transportation corridors and surrounded by rural agricultural lands. The other air basins in the region are less populated.

The terrain and thermally driven circulation patterns play a critical role in the accumulation and transport of pollutants throughout this region. Differential heating between the land and the sea promotes a diurnal sea breeze circulation along the coastal areas. The sea breeze promotes onshore transport of marine air, while the mountains that border the Coast Range provide a physical barrier that prevents direct intrusion of marine air into the inland San Joaquin Valley. However, during the warmer months of the year, the pressure gradient driven by temperature contrasts between the inland valley and Pacific Ocean, promotes transport of marine air through the San Francisco Bay and into the northern end of the San Joaquin Valley. The mountainous terrain, combined with this pressure gradient, moves air from the northern end of the valley towards the southern end of the valley. The Hoover Wilderness Area, one of the Class I areas in Central California, is shown below in Figure C-58.

Figure C-58: Hoover Wilderness Area

Photo courtesy of Nicole Dolney

Emissions from urban areas, transportation corridors, and agricultural areas are entrained as air moves through the valley. The mountains surrounding the San Joaquin Valley limit dispersion. Meteorological conditions routinely promote formation of a shallow mixed layer throughout the valley and surrounding foothills, concentrating pollutants and further limiting dispersion. Differential heating between the valleys and the mountains promotes localized mountain valley flow, where accumulated emissions are recirculated within the valley and the flanks of the mountainous areas that surround the valley.

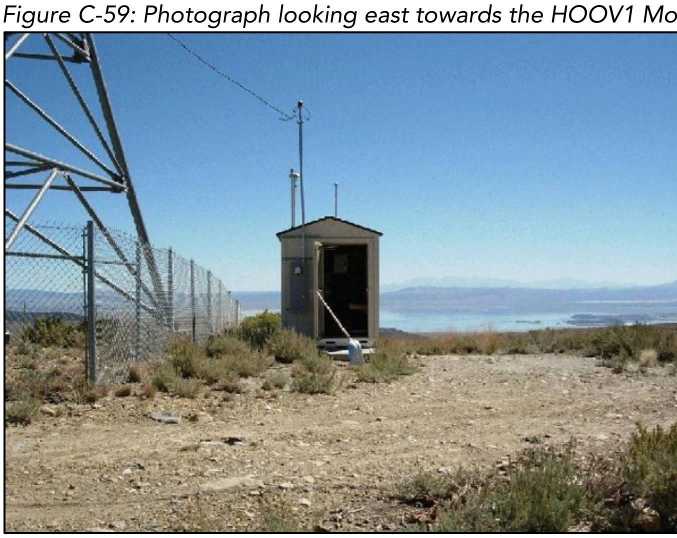
Emissions from the San Joaquin Valley Air Basin account for most of the region's emissions. The San Joaquin Valley is one of the most productive agricultural areas in the U.S., accounting for nearly two thirds of all fruit and nut production in the country. The movement of goods and people through the San Joaquin Valley and surrounding areas is the dominant source of emissions. Mobile sources accounted for nearly 80 percent of the region's NOx emissions in 2014 and were the largest emission source sector for each of the air basins in the Central California region.

Five IMPROVE monitoring sites are in the Central California region. From north to south, the monitoring sites in this region are located in or near the Hoover Wilderness Area, Kaiser Wilderness Area, Pinnacles National Park, San Rafael Wilderness Area, and Sequoia National Park. The following section provides an overview of the monitoring site, visibility monitoring data, and source apportionment for each location.

Hoover Wilderness Area (HOOV1) IMPROVE Monitoring Site

The HOOV1 monitoring site, shown in Figure C-59, is located at 8,398 feet (2,560 m) asl, east of the Hoover Wilderness Area. The monitoring site was established in July 2001, just east Conway Summit and U.S. Highway 395. Mono Lake is southeast of the site. The highway is the main thoroughfare along the eastern side of Sierra Nevada Mountains but is lightly traveled relative to most highways in California. Cal Trans traffic count data reported an annual average daily traffic count of 4,100 vehicles in 2017 at the Lee Vining visitor center, just a few miles south of the site.[9] Data collected at the HOOV1 monitoring site are representative of visibility conditions in the Hoover Wilderness Area.

Figure C-59: Photograph looking east towards the HOOV1 Monitoring Site



Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

[9] *https://dot.ca.gov/programs/traffic-operations/census/traffic-volumes/2017*

The Hoover Wilderness Area spans 47,916 acres and is characterized by dramatic mountainous terrain rising abruptly from the Great Basin to the crest of the Sierra Nevada Mountains. Numerous high alpine lakes, meadows, and isolated stands of aspen, cottonwood, hemlock, and pine populate the landscape. The Hoover Wilderness Area is in the Great Basin Valleys Air Basin.

As shown in Table C-8, visibility impairment on the clearest days during the baseline period was 1.4 dv. Visibility impairment on the clearest days decreased by 0.4 dv between the baseline and the current periods. During the current period, visibility impairment was 1.0 dv, which corresponds to a visual range of 219 miles (353 km).

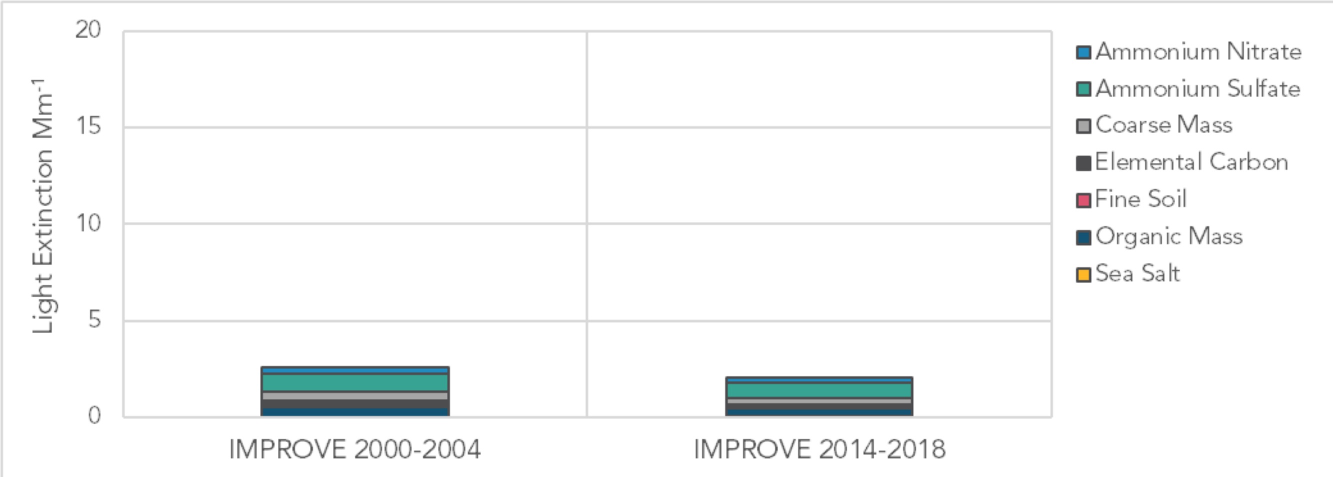
Visibility impairment on the most impaired days during the baseline period was 8.9 dv. Visibility impairment on the most impaired days decreased by 1.1 dv between the baseline and the current periods. During the current period visibility impairment was 7.8 dv, which is equivalent to a visual range of 111 miles (179 km). The average rate of progress between the baseline and current periods was 0.08 dv per year. This rate is faster than the URP and more than double the adjusted URP.

Table C-8: Visibility Tracking Metrics for HOOV1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	1.4	1.0	0.1	0.4 dv	0.9 dv	--	--
Most Impaired	8.9	7.8	4.9	1.1 dv	2.9 dv	0.07 dv/year (0.03 dv/year)	0.08 dv/year

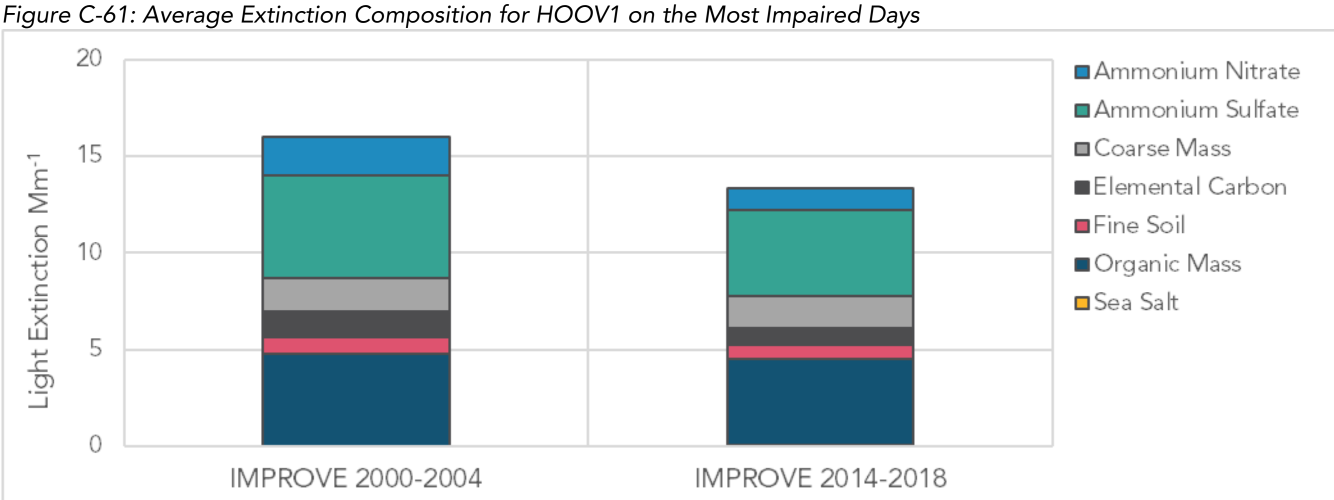
Monitoring data shown in Figure C-60 indicates that on the clearest days, ammonium sulfate accounts for the largest portion of light extinction at the HOOV1 monitoring site. Between the baseline period and current period, light extinction from ammonium sulfate decreased by 13 percent.

Figure C-60: Average Extinction Composition for HOOV1 on the Clearest Days



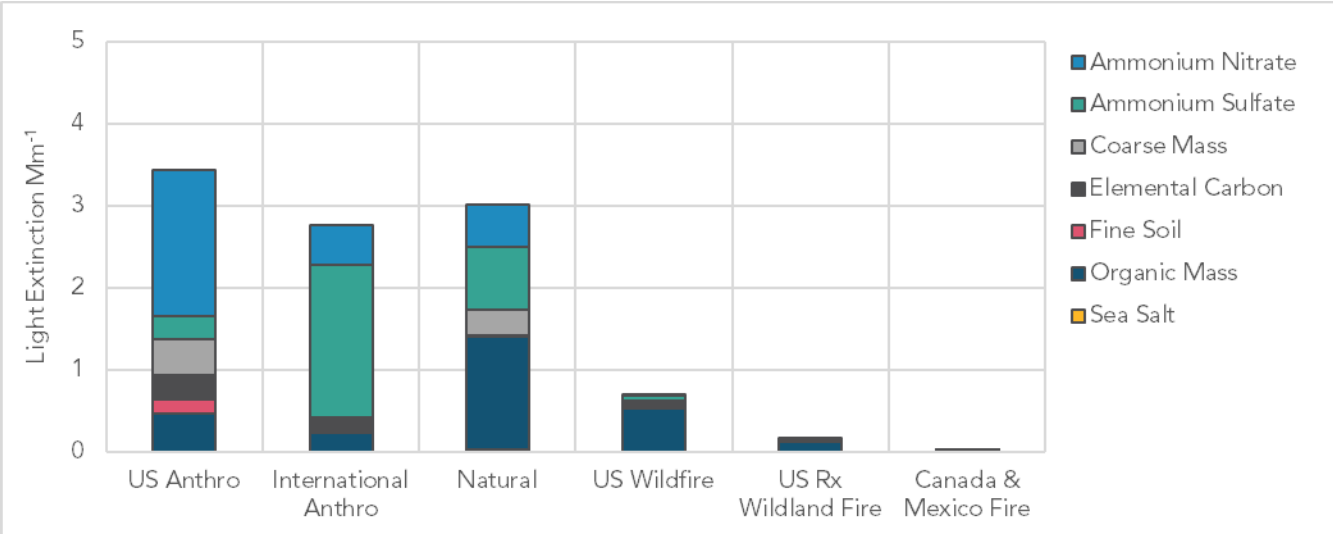
As shown in Figure C-61, ammonium sulfate and organic mass combine to account for over 60 percent of light extinction on the most impaired days. Between the baseline and current periods, light extinction from ammonium sulfate and organic mass on the most impaired days decreased by 17 percent and 7 percent, respectively.

Figure C-61: Average Extinction Composition for HOOV1 on the Most Impaired Days



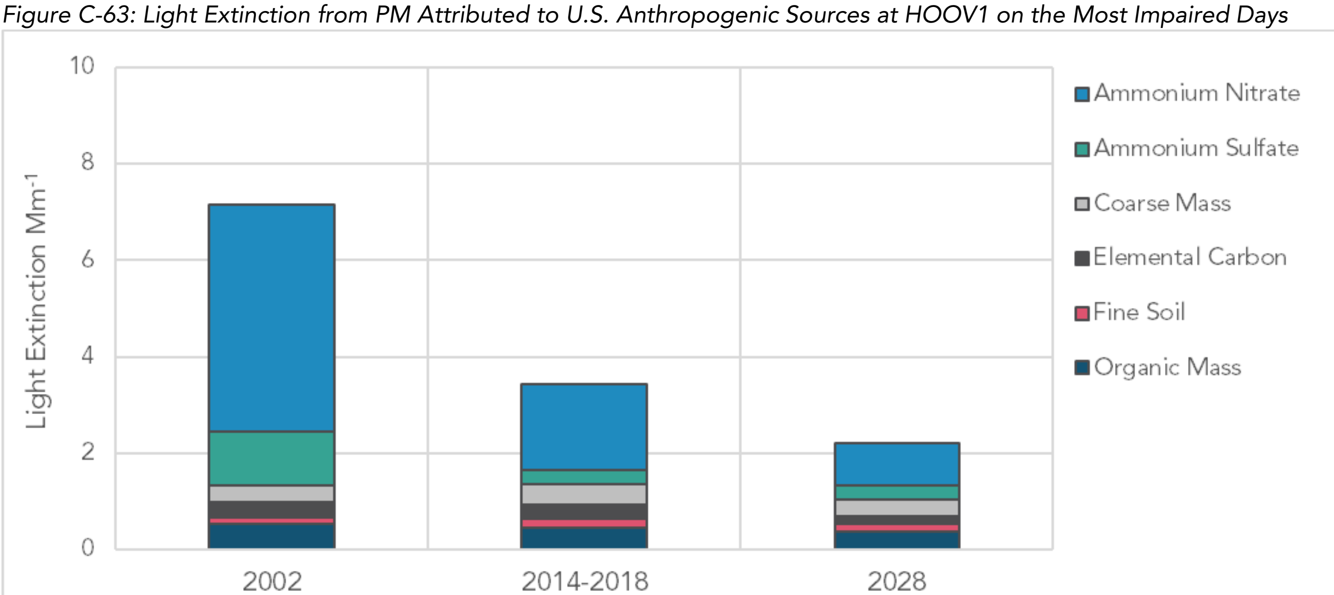
Source apportionment modeling, shown in Figure C-62, indicates that emissions from U.S., international, and natural sources make the largest contributions to impairment in the Hoover Wilderness Area. Light extinction from ammonium sulfate is primarily attributable to international and natural emissions, whereas organic mass is primarily from natural emissions and wildfires. Light extinction from U.S. sources is dominated by ammonium nitrate.

Figure C-62: Source Apportionment Modeling Results for HOOV1 on the Most Impaired Days in 2014-2018



As shown in Figure C-63, light extinction attributable to ammonium nitrate has decreased markedly between the baseline and current periods. Between the current period and 2028, light extinction attributable ammonium nitrate is projected to decrease by an additional 50 percent. Ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. emission sources in 2028.

Figure C-63: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at HOOV1 on the Most Impaired Days



The results of regional source apportionment projections for ammonium nitrate and ammonium sulfate are shown in Figures C-64 and C-65. Light extinction attributable to ammonium nitrate is projected to be more than double ammonium sulfate. California mobile source emissions are projected to make the largest contribution to ammonium nitrate in 2028.

Figure C-64: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at HOOV1

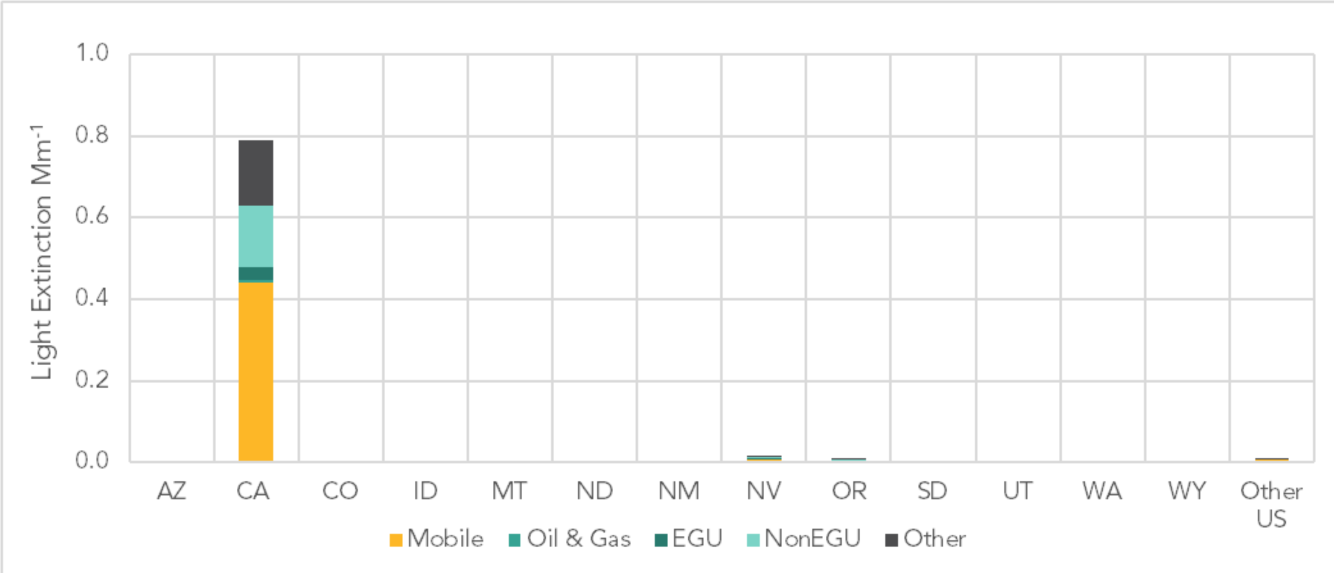
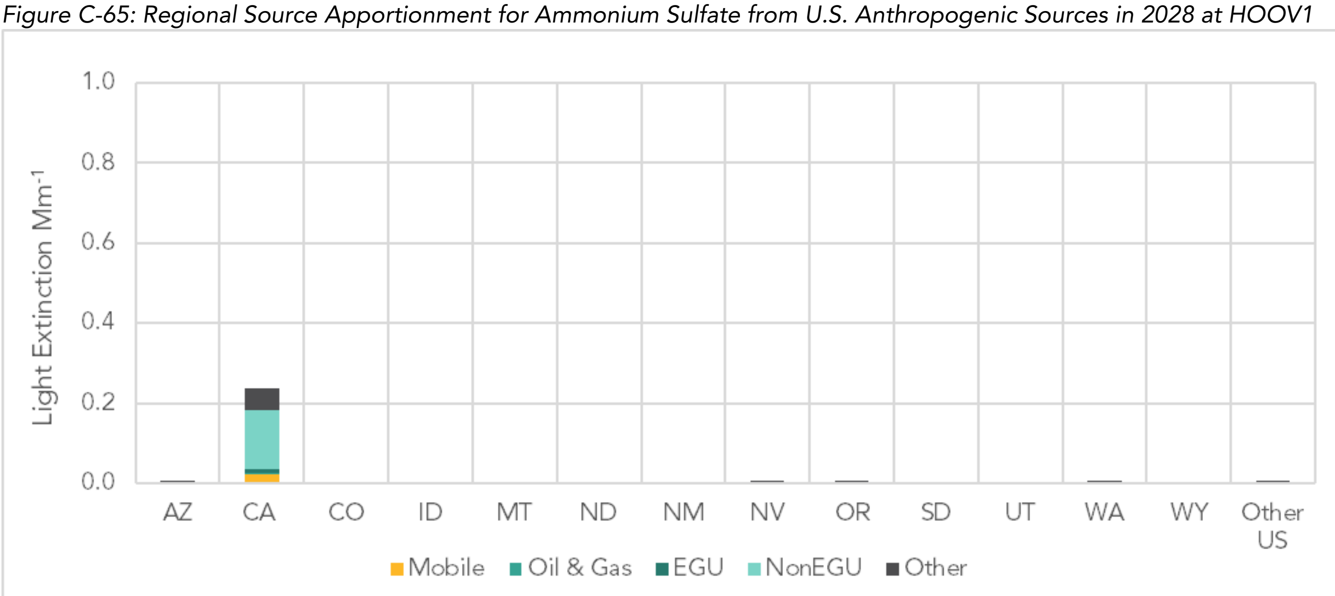
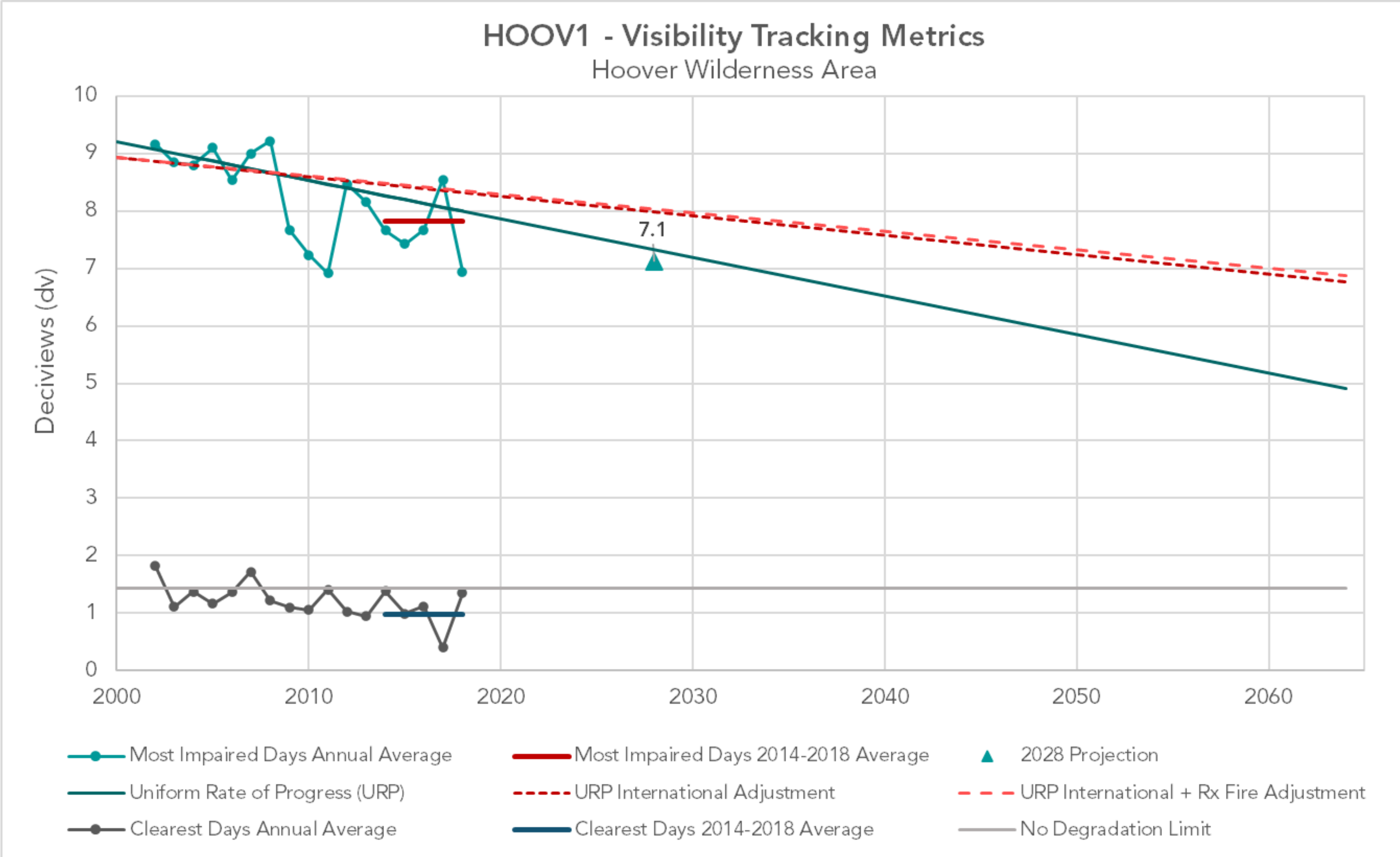


Figure C-65: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at HOOV1



California's long-term strategy for regional haze is focused reducing NOx emissions from mobile sources. Projections indicate that this focus will lead to visibility benefits in the Hoover Wilderness Area. The current and projected trends for visibility tracking metrics at the Hoover Wilderness Area are shown in Figure C-66. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 7.1 dv in 2028, which is comparable to a visual range of 119 miles (192 km). This 2028 projection is below the adjusted glidepath that accounts for international emissions and wildland prescribed fire emissions, indicating visibility in the Hoover Wilderness Area is on track to meet 2064 targets.

Figure C-66: Visibility Tracking Metrics and Projections for the Hoover Wilderness Area



Kaiser Wilderness Area (KAIS1) IMPROVE Monitoring Site

The KAIS1 monitoring site, shown in Figure C-67, is located near the southern border of the Kaiser Wilderness at 8,520 feet (2,597 m) asl. The monitoring site was established in January 2000 southeast of Huntington Lake, on the backside of the Summit Ski Patrol Hut at China Peak Mountain Resort. Data collected at this site are representative of visibility conditions in the Ansel Adams, John Muir, and Kaiser Wilderness Areas.

Figure C-67: Photograph looking southeast towards the KAIS1 Monitoring Site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

The Ansel Adams Wilderness Area covers 109,484 acres. When it was first established in 1964, it was known as the Minarets Wilderness. It was renamed in tribute to the well-known nature photographer and environmentalist following his death in 1984. The landscape is characterized by stunning mountains and glacial carved valleys. Elevations range from 3,500 to 13,157 feet (1,067 to 4,010 m) asl. The southern portion of Ansel Adams Wilderness is in the San Joaquin Valley Air Basin and the northern portion is in the Great Basin Valleys Air Basin.

The John Muir Wilderness Area stretches along the crest of the Sierra Nevada Mountains. It spans 484,673 acres and is contiguous with several Class I areas including the Ansel Adams Wilderness Area, Kings Canyon National Park, and Sequoia National Park. Most of the John Muir Wilderness Area is in the San Joaquin Valley Air Basin except for the eastern edge, which is in the Great Basin Valleys Air Basin. Elevations range from 4,000 feet to 14,496 feet (1,219 to 4,418 m) asl. Lower elevations are dominated by mixed forests of pine, cedar, and fir whereas higher elevations are barren granite replete with numerous alpine lakes. Due to the proximity to California's major cities, this area sees very heavy usage and quota systems are in place to limit overnight use during the busiest periods.

The Kaiser Wilderness Area was established in 1976 and includes 22,500 acres. The Kaiser Wilderness Area is in the San Joaquin Valley Air Basin. Elevation ranges from 6,600 to 9,370 feet (2,012 to 2,856 m) asl. The terrain in the southern portion is dominated by dense stands of fir and pine forest. Forest cover in the northern portion is less dense and alpine lakes dot the landscape.

As shown in Table C-9, visibility impairment on the clearest days during the baseline period was 2.3 dv. Visibility impairment on the clearest days decreased by 0.8 dv between the baseline and the current periods. During the current period, visibility impairment on the clearest days was 1.5 dv, which corresponds to a visual range of 209 miles (336 km).

Visibility impairment on the most impaired days during the baseline period was 12.9 dv. Visibility impairment on the most impaired days decreased by 1.9 dv between the baseline and the current periods. During the current period, visibility impairment on the most impaired days was 11.0 dv, which corresponds to a visual range of 81 miles (130 km).

Table C-9: Visibility Tracking Metrics for KAIS1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	2.3	1.5	0.0	0.8 dv	1.5 dv	--	--
Most Impaired	12.9	11.0	6.1	1.9 dv	4.9 dv	0.11 dv/year (0.06 dv/year)	0.14 dv/year

Like monitoring data from the YOSE1 monitoring site, monitoring data from the KAIS1 site indicate that ammonium sulfate and organic mass have the most dominant impact on light extinction on the clearest days and the most impaired days except for the most impaired days during the baseline monitoring period (Figures C-68 and C-69). During the baseline period, ammonium nitrate accounted for the largest portion of light extinction on the most impaired days, closely followed by ammonium sulfate and organic mass.

Visibility impairment attributable to these key visibility reducing PM species has markedly decreased between the baseline and current periods. Light extinction attributable to ammonium nitrate on the most impaired days decreased by 52 percent. Light extinction attributable to organic mass decreased by 26 percent on the clearest days and 17 percent on the most impaired days. Light extinction attributable to ammonium sulfate decreased by 14 percent and 12 percent on the clearest and most impaired days, respectively.

Figure C-68: Average Extinction Composition for KAIS1 on the Clearest Days

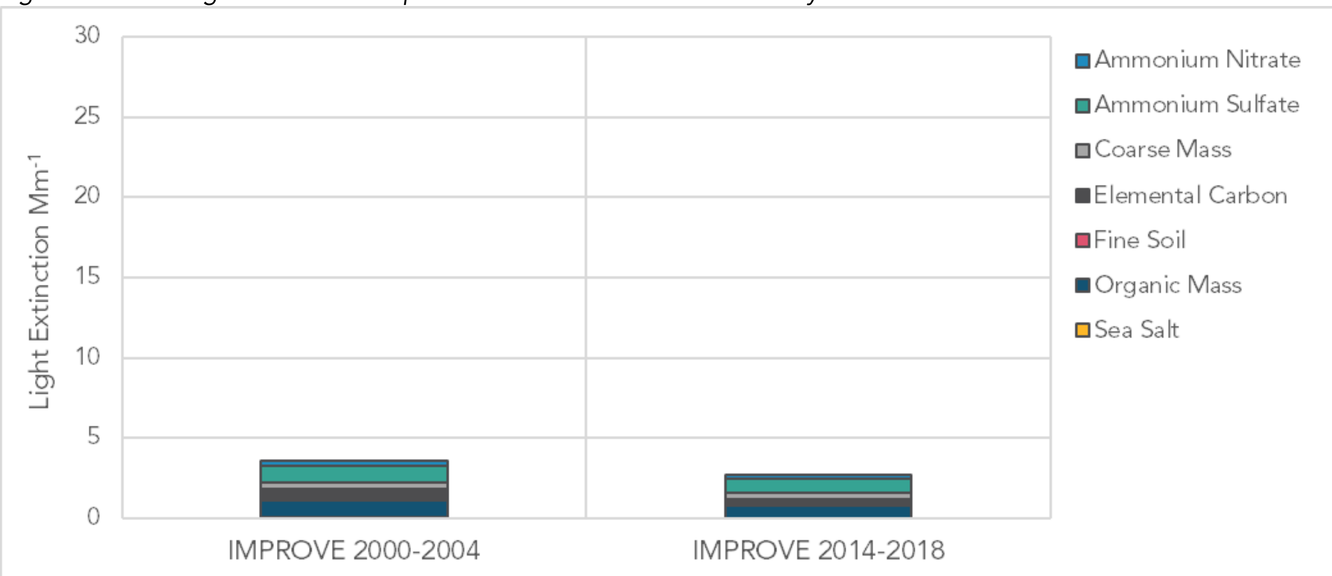
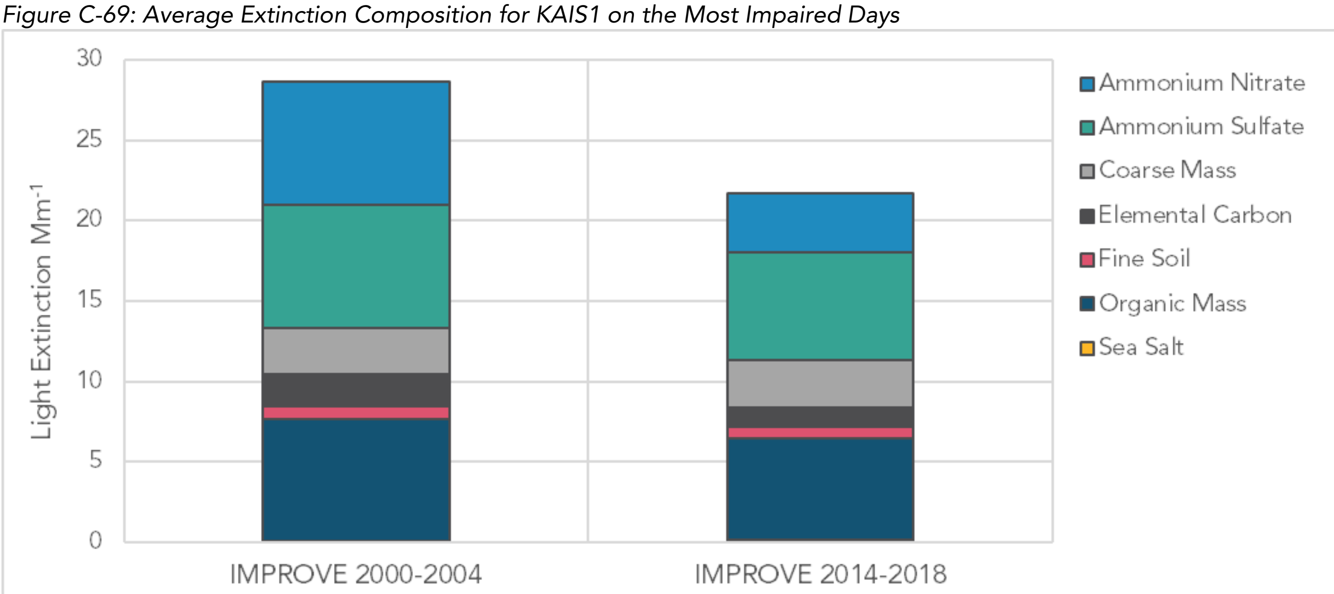
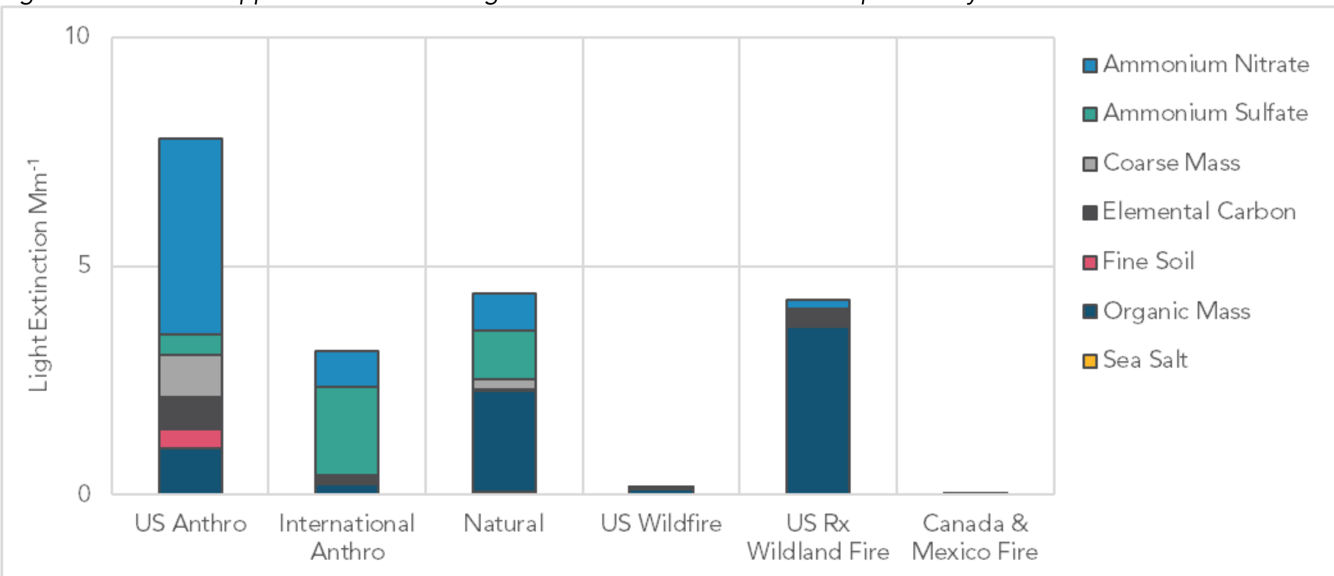


Figure C-69: Average Extinction Composition for KAIS1 on the Most Impaired Days



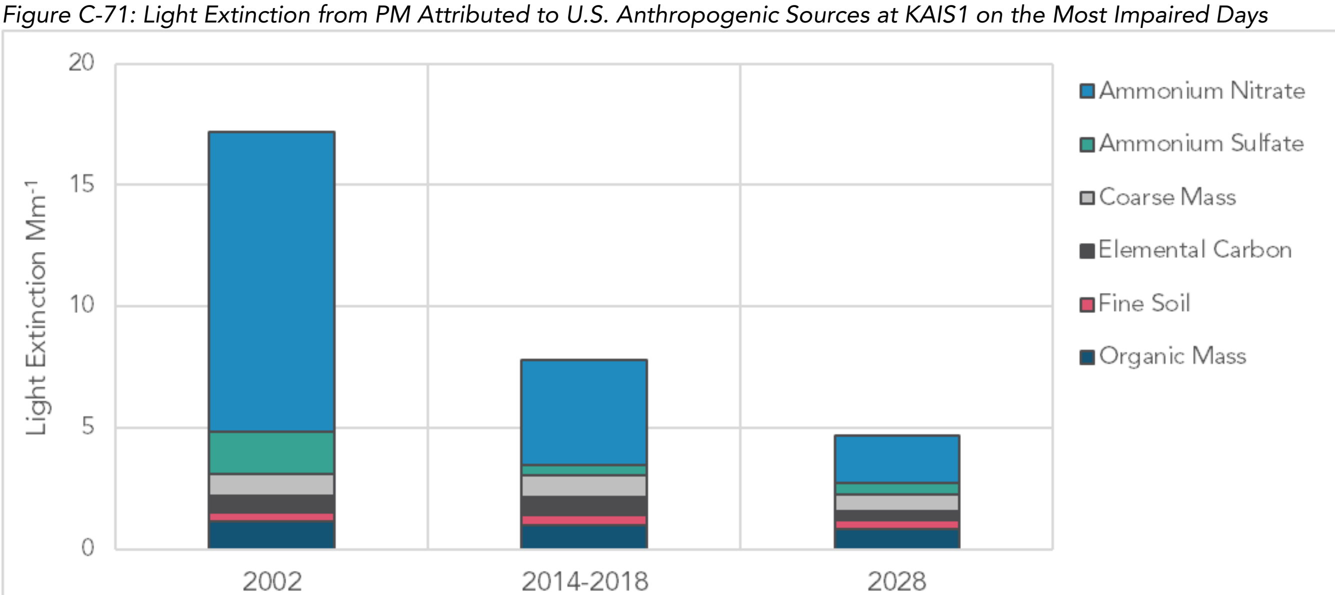
Source apportionment modeling, shown in Figure C-70, indicates that U.S. sources, wildland fire, natural sources, and international sources contribute to visibility impairment at the KAIS1 monitoring site. Light extinction attributable to organic mass is primarily from fire and natural emission sources, whereas ammonium sulfate is primarily attributable to international and natural emission sources. The portion of light extinction attributed to U.S. sources is dominated by ammonium nitrate.

Figure C-70: Source Apportionment Modeling Results for KAIS1 on the Most Impaired Days in 2014-2018



As shown in Figure C-71, light extinction between the baseline and current periods decreased significantly. Further decreases are expected moving forward. Between the current period and 2028, adopted emission controls are expected to reduce light extinction attributable to ammonium nitrate by an additional 56 percent. Ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. emission sources in 2028.

Figure C-71: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at KAIS1 on the Most Impaired Days



Regional source apportionment projections are shown in Figures C-72 and 73. California mobile sources are projected to account for the largest share of light extinction attributable to ammonium nitrate. The share of light extinction attributable to ammonium nitrate from U.S. sources is much greater than the share from ammonium sulfate. California's regional haze strategy for this planning period is focused on NOx, the precursor to ammonium nitrate formation. This focus is expected to benefit visibility in the Ansel Adams, John Muir, and Kaiser Wilderness Areas.

Figure C-72: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at KAIS1

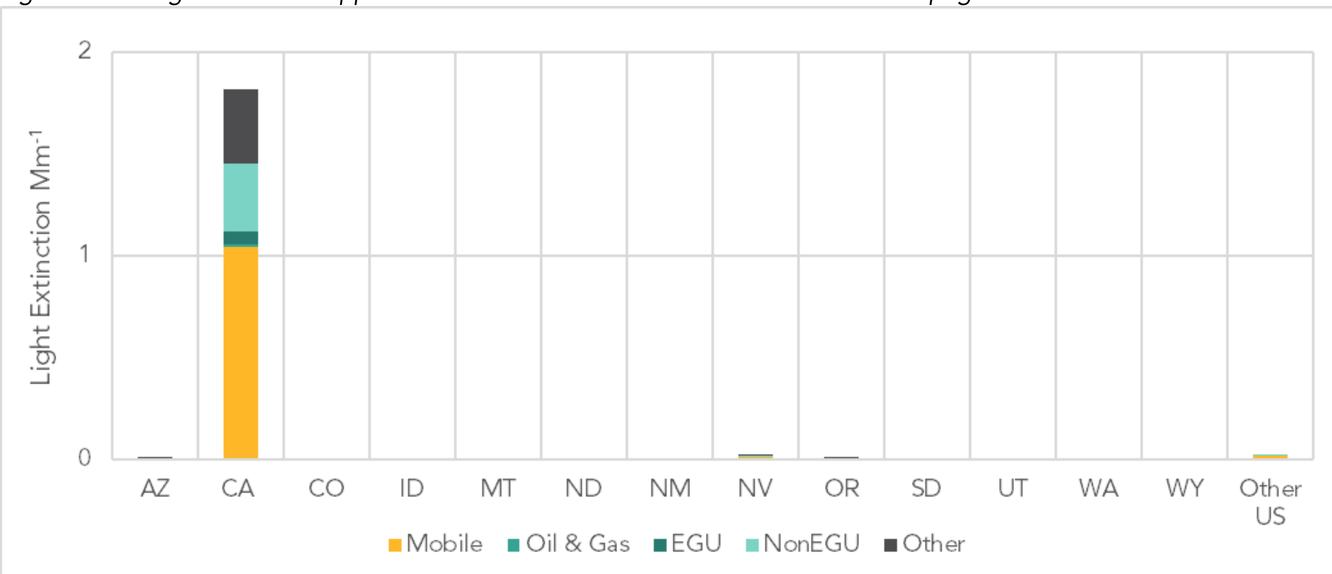
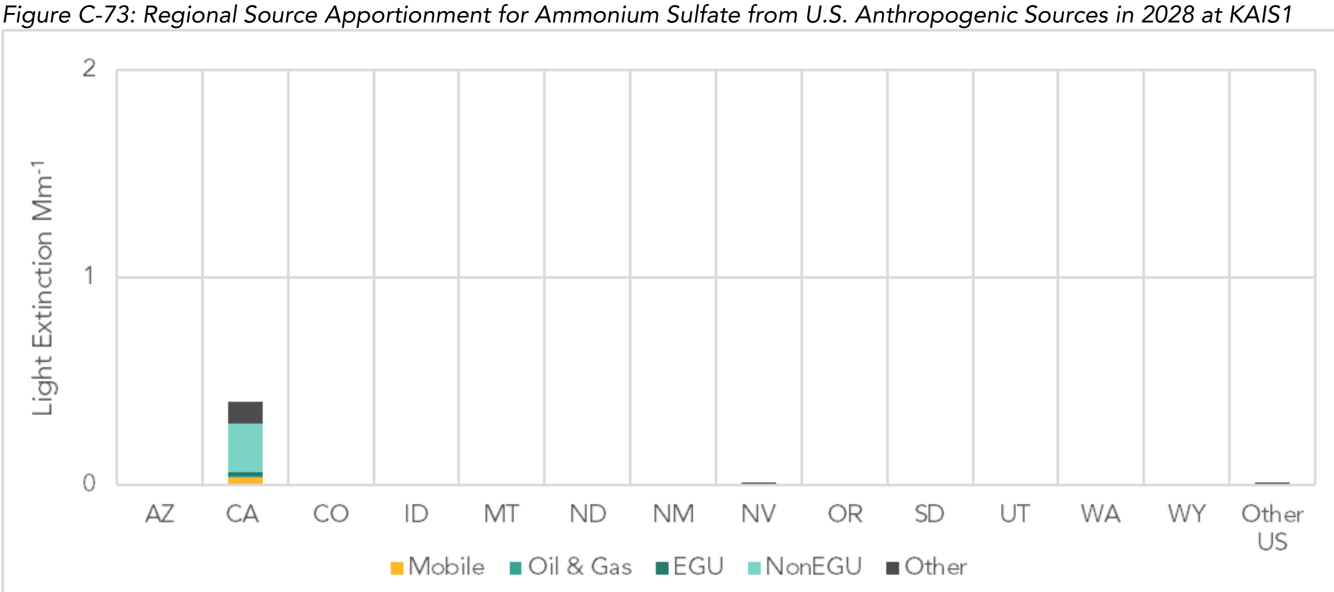
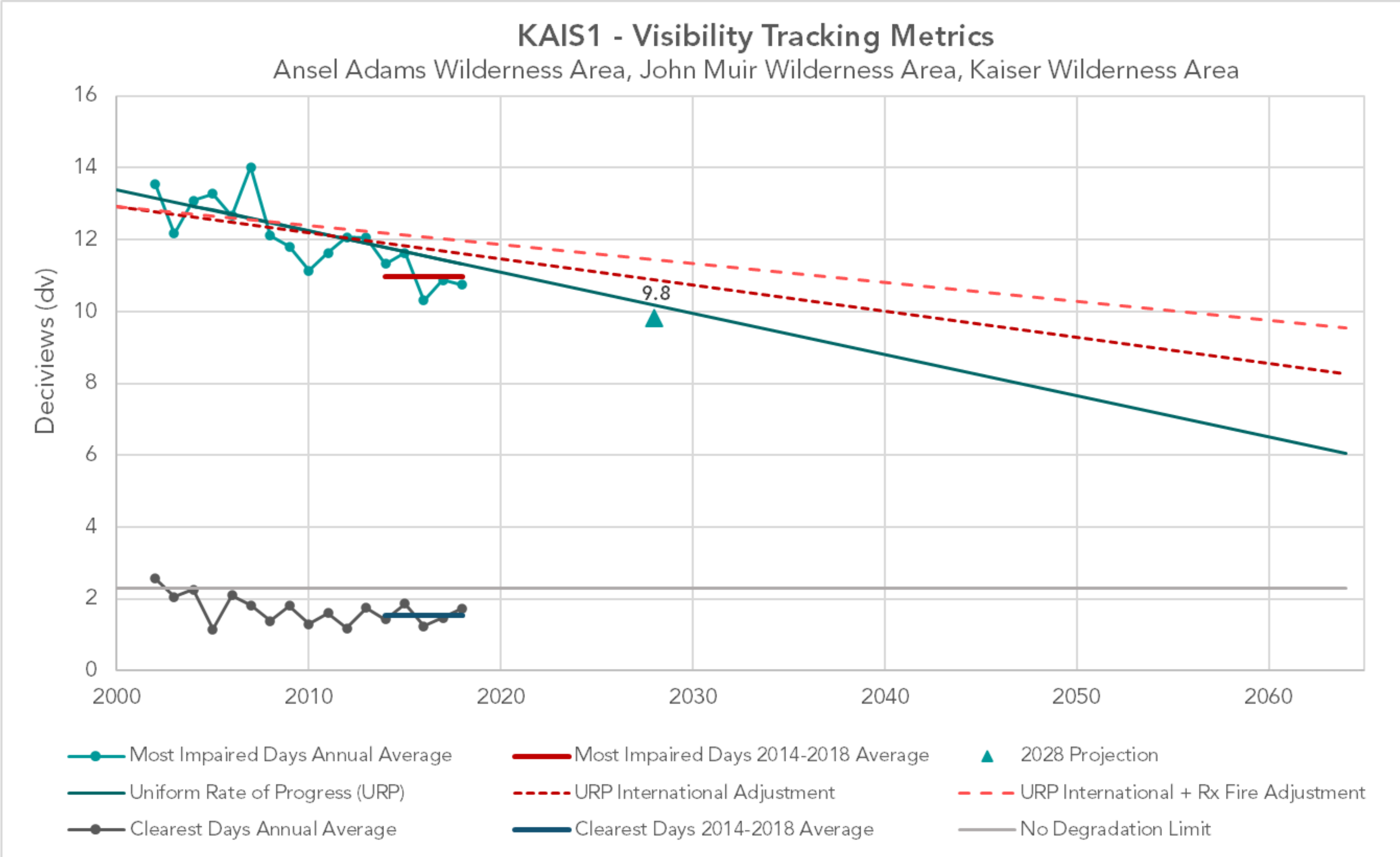


Figure C-73: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at KAIS1



The current and projected trends in the visibility tracking metrics for the Ansel Adams, John Muir, and Kaiser Wilderness Areas are shown in Figure C-74. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 9.8 dv in 2028, which is comparable to a visual range of 91 miles (146 km). This 2028 projection is below the adjusted glidepath which accounts for international and wildland prescribed fire emissions, indicating that visibility in these areas is on track to meet 2064 targets.

Figure C-74: Visibility Tracking Metrics and Projections for the Ansel Adams, John Muir, and Kaiser Wilderness Areas



Pinnacles National Park (PINN1) IMPROVE Monitoring Site

The PINN1 monitoring site, shown in Figure C-75, is located at 991 feet (302 m) asl near the eastern border of Pinnacles National Park. The monitoring site was established in March 1988, southwest of the east entrance. Pinnacle National Park's 134 site developed campground is located just inside the east entrance. Each camp site is equipped with a fire ring and campfires are generally allowed. RV sites have electrical hookups. Data collected at this monitoring site are representative of the visibility conditions in Pinnacles National Park and the Ventana Wilderness Area.

Figure C-75: Photograph looking southwest towards the PINN1 Monitoring Site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

Pinnacles National Park spans 12,952 acres. It was originally established as a national monument but was redesignated as a national park in 2013. The landscape is a mix of oak woodlands and chaparral covered hills, and towering rock spires. The Ventana Wilderness Area is 95,152 rugged acres with dense communities of chaparral, oak woodlands, and pine stands. Pinnacles National Park and Ventana Wilderness Area are in the North Central Coast Air Basin.

As shown in Table C-10, visibility impairment on the clearest days during the baseline period was 8.9 dv. Visibility impairment on the clearest days decreased by 1.2 dv between the baseline and the current periods. During the current period, visibility impairment was 7.7 dv which is comparable to a visual range of 112 miles (181 km).

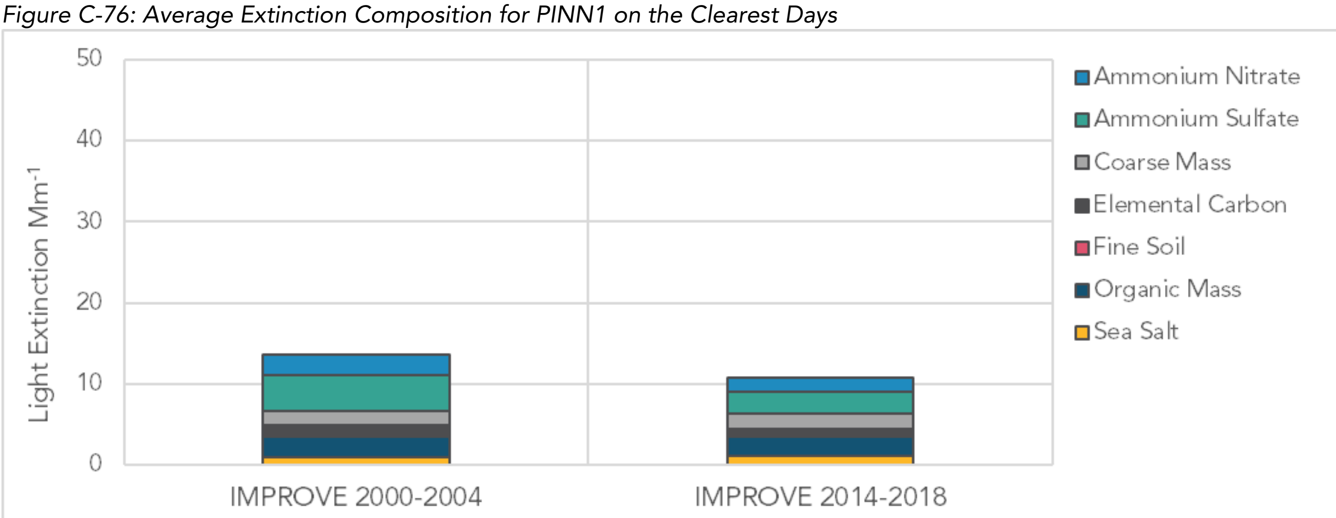
Visibility impairment on the most impaired days during the baseline period was 17.0 dv. Visibility impairment on the most impaired days decreased by 2.9 dv between the baseline and current periods. During the current period, visibility impairment was 14.1 dv, which is comparable to a visual range of 59 miles (95 km). The rate of progress between the baseline and current periods averaged 0.21 dv per year. This rate is faster than both the URP and the adjusted URP.

Table C-10: Visibility Tracking Metrics for PINN1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	8.9	7.7	3.5	1.2 dv	4.2 dv	--	--
Most Impaired	17.0	14.1	6.9	2.9 dv	7.2 dv	0.17 dv/year (0.13 dv/year)	0.21 dv/year

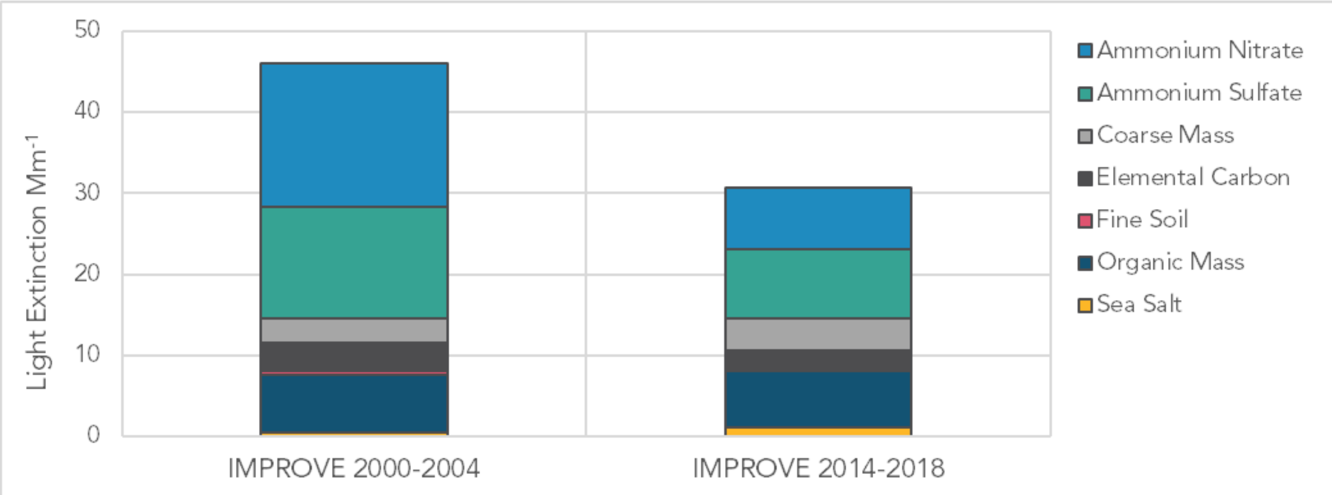
Monitoring data, shown in Figures C-76, indicates that on clearest days ammonium sulfate accounts for the largest portion of light extinction. Between the baseline period and the current period, light extinction attributed to ammonium sulfate decreased by 38 percent on the clearest days.

Figure C-76: Average Extinction Composition for PINN1 on the Clearest Days



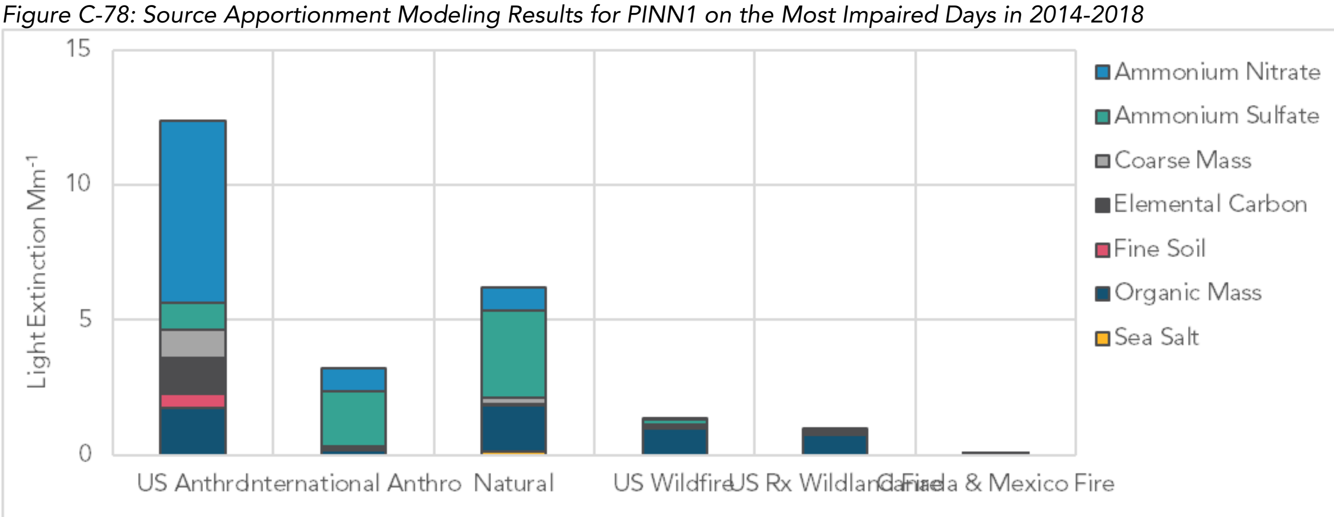
As shown in Figure C-77, ammonium nitrate and ammonium sulfate accounted for the largest portion of light extinction on the most impaired days. Between the baseline monitoring period and the current period, light extinction attributable to ammonium nitrate decreased by 57 percent and light extinction attributable to ammonium sulfate decreased by 38 percent on the most impaired days.

Figure C-77: Average Extinction Composition for PINN1 on the Most Impaired Days



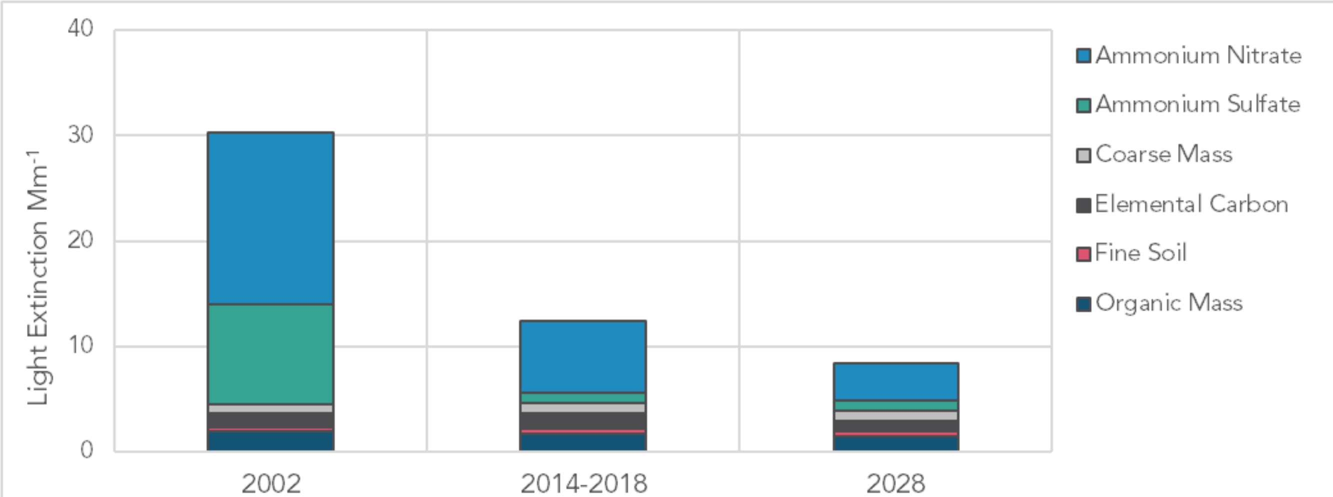
Source apportionment modeling, shown in Figure C-78, indicates that U.S. emissions are the dominant source of visibility reducing particles measured at the PINN1 monitoring site. Emissions from natural sources, international sources, and fire also contribute to visibility impairment at the site. Ammonium nitrate is the dominant source of light extinction attributable to U.S. sources whereas ammonium sulfate is the dominant source of light extinction attributable to international and natural sources. Organic mass is the dominant source of light extinction attributable to fire sources.

Figure C-78: Source Apportionment Modeling Results for PINN1 on the Most Impaired Days in 2014-2018



As shown in Figure C-79, light extinction from ammonium nitrate and ammonium sulfate decreased substantially between the baseline and current periods. Between the current period and 2028, adopted emissions controls are expected to reduce light extinction attributable to ammonium nitrate by and additional 49 percent. Ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. emission sources on the most impaired days in 2028.

Figure C-79: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at PINN1 on the Most Impaired Days



Regional source apportionment projections are shown in Figures C-80 and C-81. Mobile sources operating in California are projected to account for the largest share of light extinction attributable to ammonium nitrate. Light extinction attributable to ammonium sulfate is projected to be less than one-third of the amount of light extinction attributable to ammonium nitrate. California's long-term strategy is focused on reducing NOx emissions from mobile sources. This strategy is expected to yield visibility improvements for areas represented by the PINN1 monitor.

Figure C-80: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at PINN1

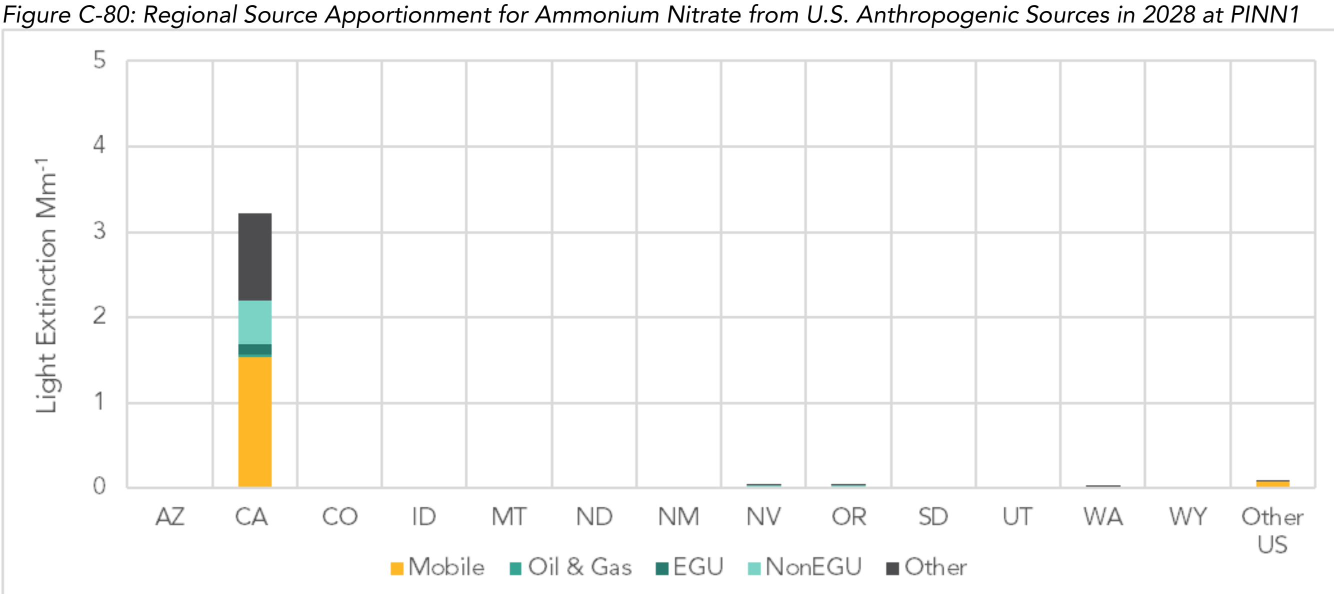
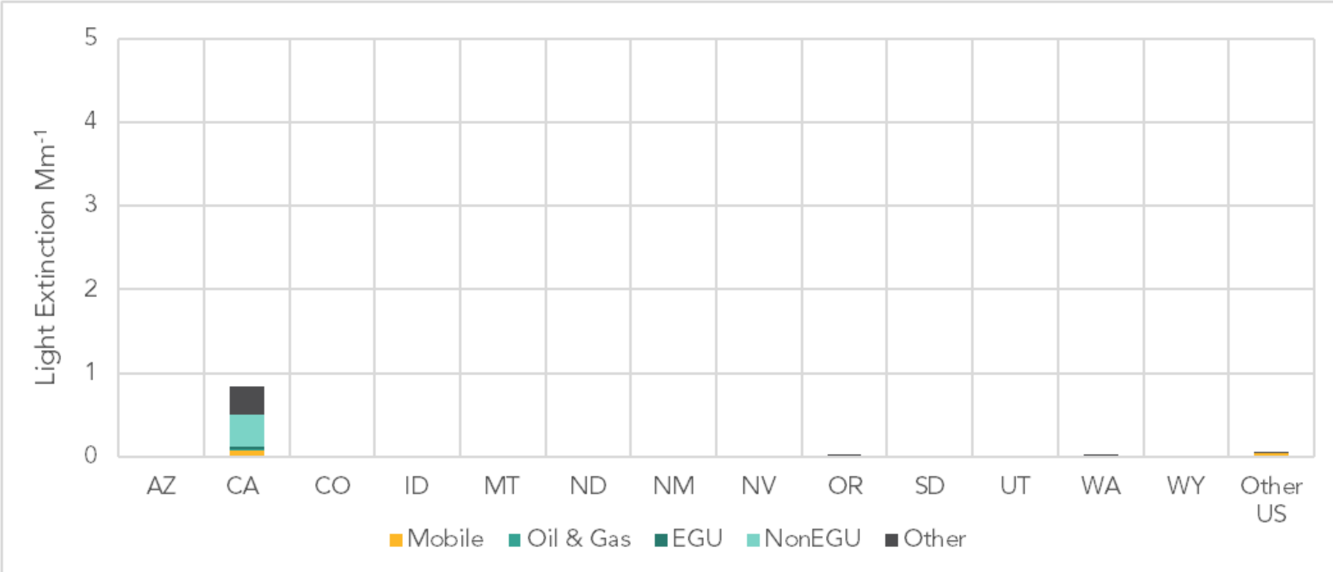
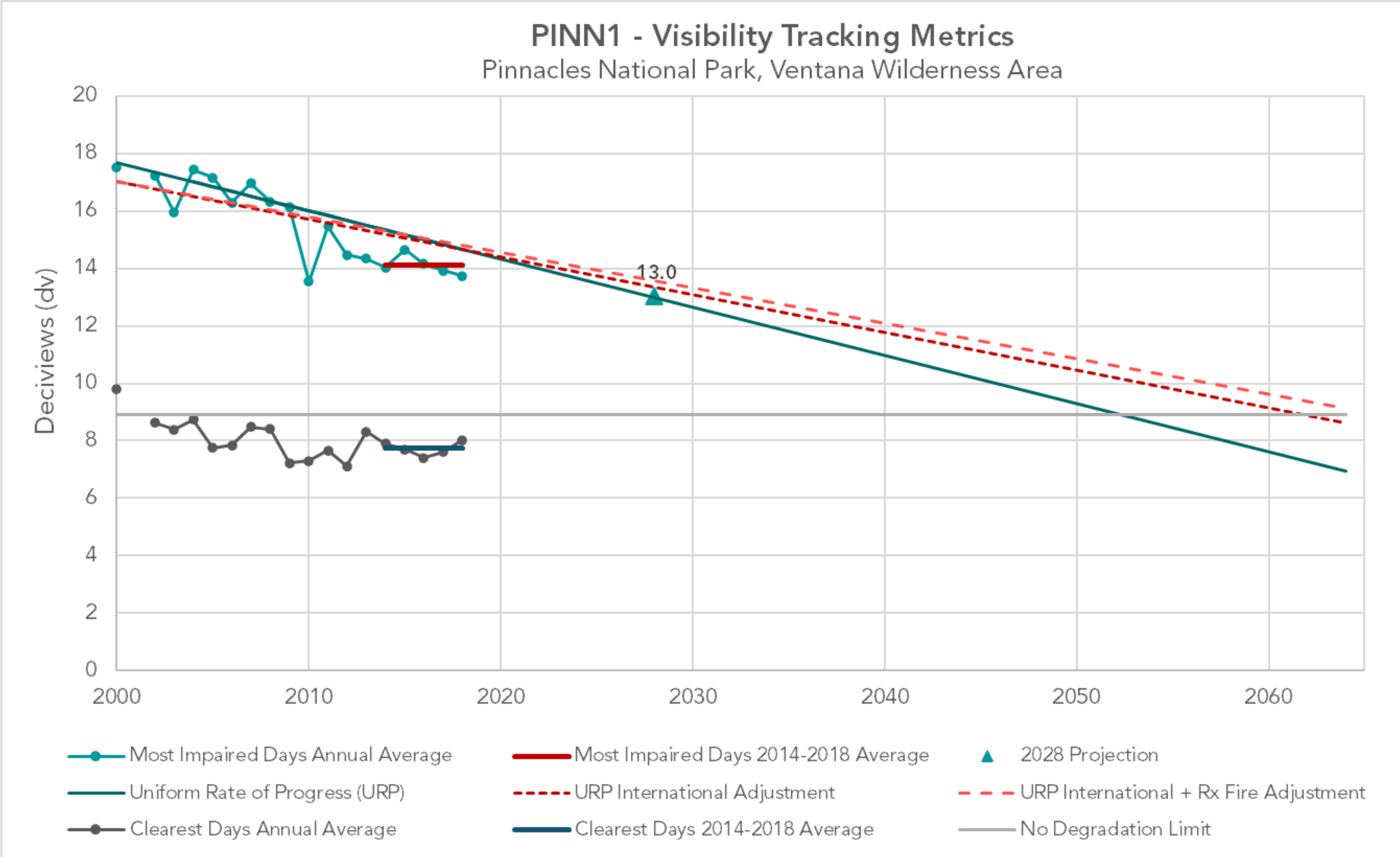


Figure C-81: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at PINN1



The current and projected visibility tracking metrics for Pinnacles National Park and Ventana Wilderness Area are shown in Figure C-82. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 13.0 dv, which is comparable to a visual range of 66 miles (106 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating that the progress occurring in this area is on track to meet 2064 visibility targets.

Figure C-82: Visibility Tracking Metrics and Projections for Pinnacles National Park and the Ventana Wilderness Area



Sequoia National Park (SEQU1) IMPROVE Monitoring Site

The SEQU1 monitoring site, shown in Figure C-83, is located at 1,703 feet (519 m) asl near the western edge of Sequoia National Park. The monitoring site was established in March 1992, in the residence area of park headquarters near the Ash Mountain water tank. Data collected at this site are representative of visibility conditions in Kings Canyon and Sequoia National Parks.

Figure C-83: Photograph looking northwest toward SEQUI Monitoring Site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser

Kings Canyon and Sequoia National Parks span 459,994 acres and 386,642 acres, respectively, in the southern Sierra Nevada Mountains on the east side of the San Joaquin Valley. The landscape is dramatic with deep valleys carved out by glaciers, lush meadows, dense forests, and high alpine meadows. Twelve peaks rise more than 14,000 feet (4,267 m) asl including Mt. Whitney, the tallest peak in the contiguous U.S. Both parks are located within the San Joaquin Valley Air Basin.

Due to the ease of access from several of California's urban areas, visitation to these parks is high. Kings Canyon and Sequoia National Parks each have over one million visitors annually. During the busiest summer months, more than 40,000 vehicles pass through the main entrances to these parks over the course of a month. The 14 campgrounds in these parks collectively host over 300,000 campers annually.[10]

As shown in Table C-11, visibility impairment on the clearest days during the baseline period was 8.8 dv. Visibility impairment on the clearest days decreased by 1.8 dv between the

[10] *https://irma.nps.gov/STATS/Reports/Park/SEQU*

baseline and the current periods. During the current period, visibility impairment on the clearest days was 7.0 dv, which is comparable to a visual range of 120 miles (194 km).

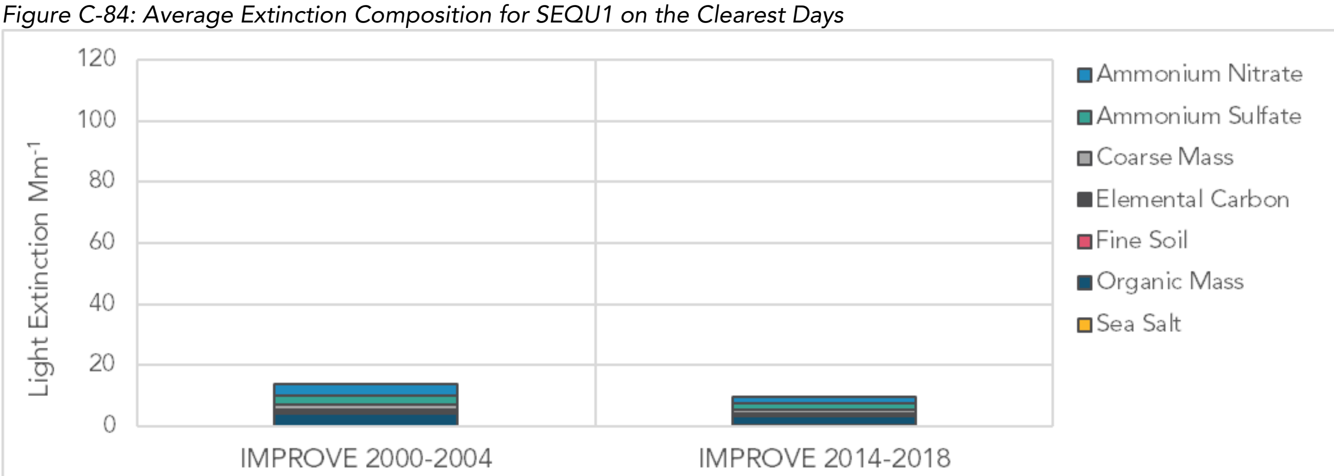
Visibility impairment on the most impaired days during the baseline period was 23.2 dv. Visibility impairment on the most impaired days decreased by 4.8 dv between the baseline and the current periods. During the current period, visibility impairment on the most impaired days was 18.4 dv, which is comparable to a visual range of 38 miles (62 km). The average rate of progress between the baseline and current periods amounted to 0.34 dv per year. This rate is faster than both the URP and the adjusted URP.

Table C-11: Visibility Tracking Metrics for SEQU1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	8.8	7.0	2.3	1.8 dv	4.7 dv	--	--
Most Impaired	23.2	18.4	6.3	4.8 dv	12.1 dv	0.28 dv/year (0.21 dv/year)	0.34 dv/year

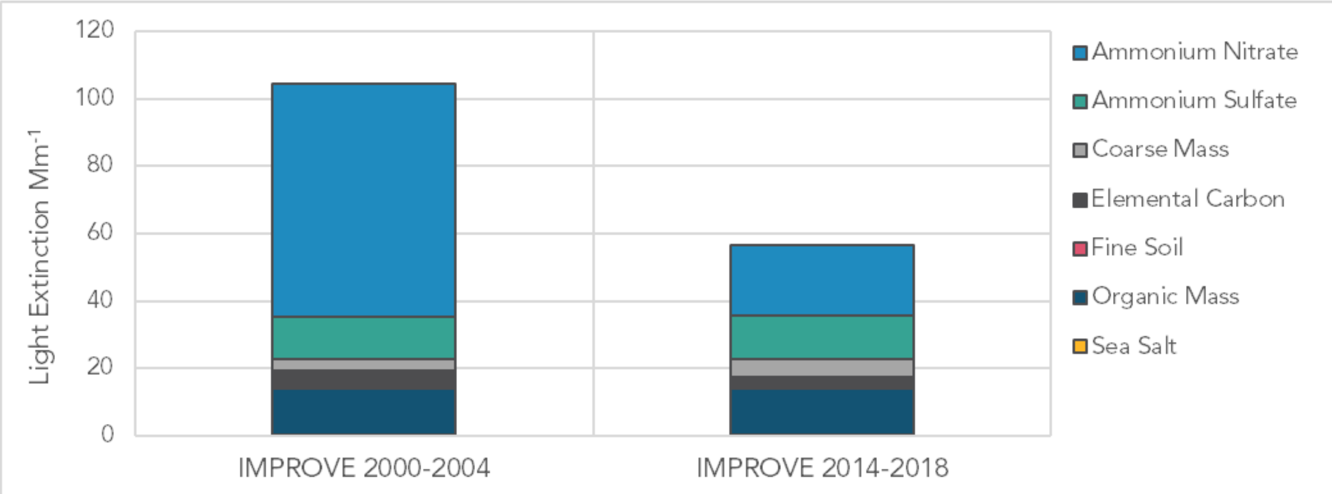
Monitoring data, shown in Figure C-84, indicates that on the clearest days during the baseline monitoring period ammonium nitrate accounted for the largest portion of light extinction. Between the baseline and current periods, light extinction attributed to ammonium nitrate decreased by 46 percent. During the current period, organic mass and ammonium sulfate accounted for the largest portion of light extinction on the clearest days.

Figure C-84: Average Extinction Composition for SEQU1 on the Clearest Days



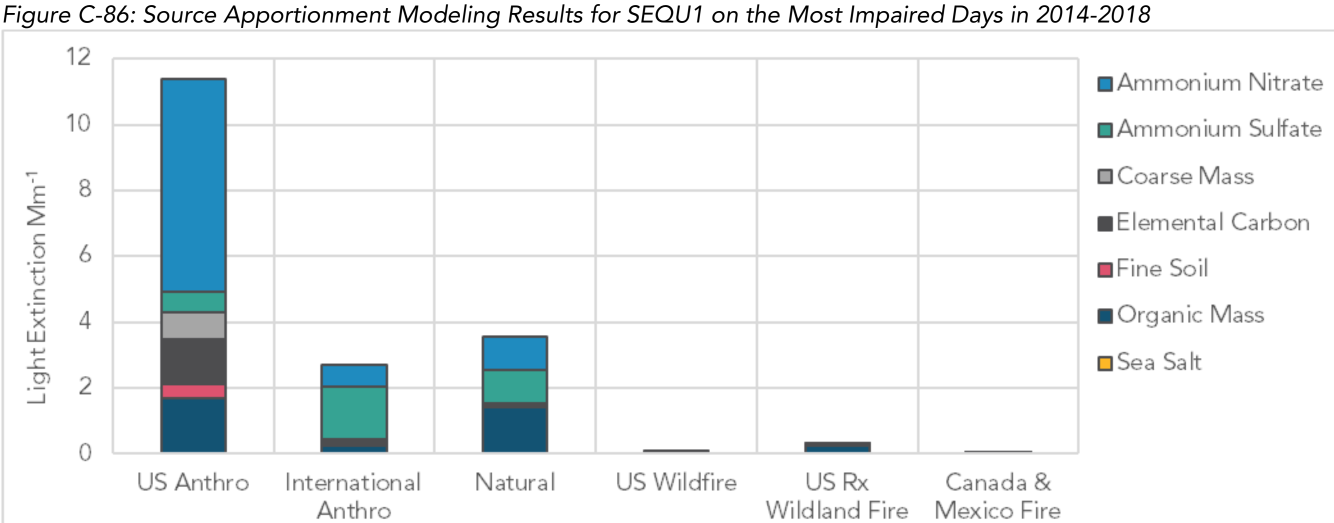
As shown in Figure C-85, ammonium nitrate is responsible for the largest portion of light extinction on the most impaired days. Between the baseline period and the current period, light extinction attributed to ammonium nitrate decreased by 70 percent on the most impaired days.

Figure C-85: Average Extinction Composition for SEQU1 on the Most Impaired Days



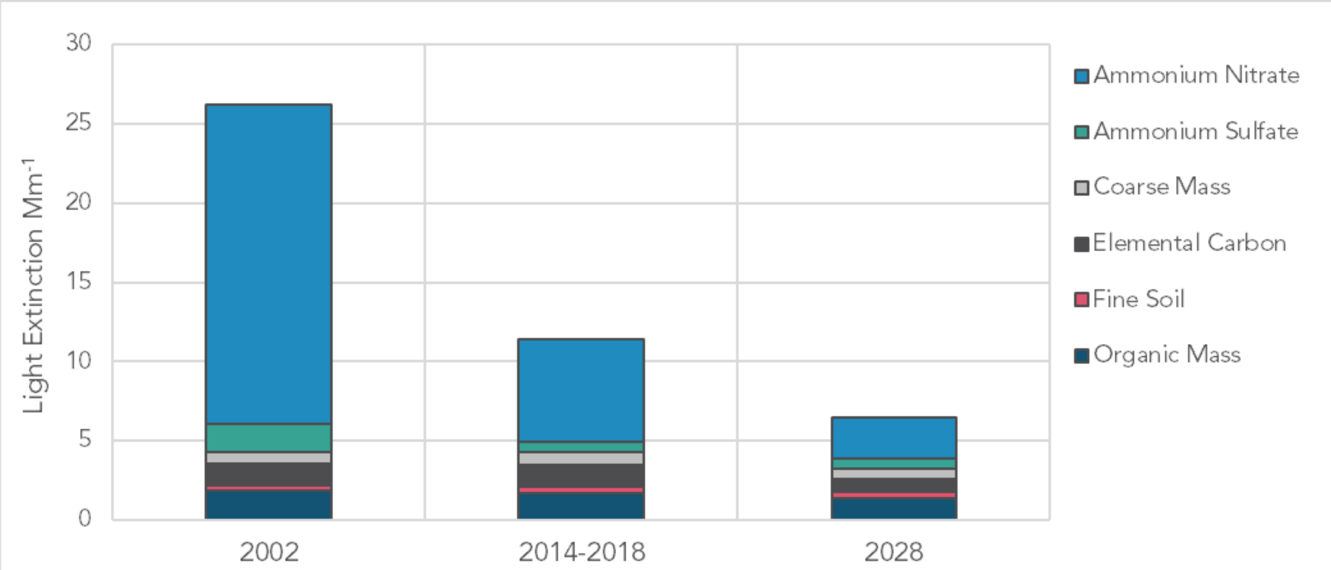
Source apportionment modeling, shown in Figure C-86, indicates that U.S. emissions are the dominant source of visibility reducing particles measured at the SEQU1 monitoring site. Emissions from natural and international sources also contribute to visibility impairment at the site. The portion of light extinction attributed to U.S. sources is dominated by ammonium nitrate. The portion of light extinction attributable to natural and international sources is dominated by organic mass and ammonium sulfate, respectively.

Figure C-86: Source Apportionment Modeling Results for SEQU1 on the Most Impaired Days in 2014-2018



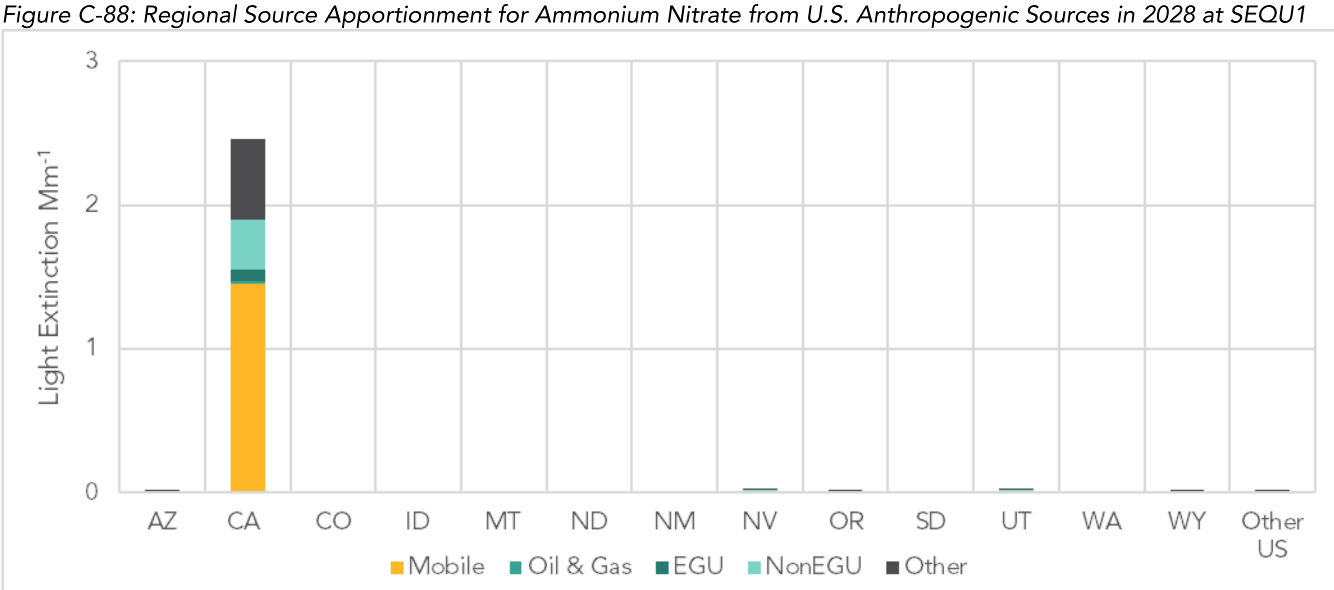
As shown in Figure C-87, light extinction attributable to ammonium nitrate has decreased significantly and further reductions are projected for 2028. Between the current period and 2028, adopted emissions controls are expected to reduce light extinction attributable to ammonium nitrate by an additional 59 percent on the most impaired days. Ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. emission sources in 2028.

Figure C-87: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at SEQU1 on the Most Impaired Days



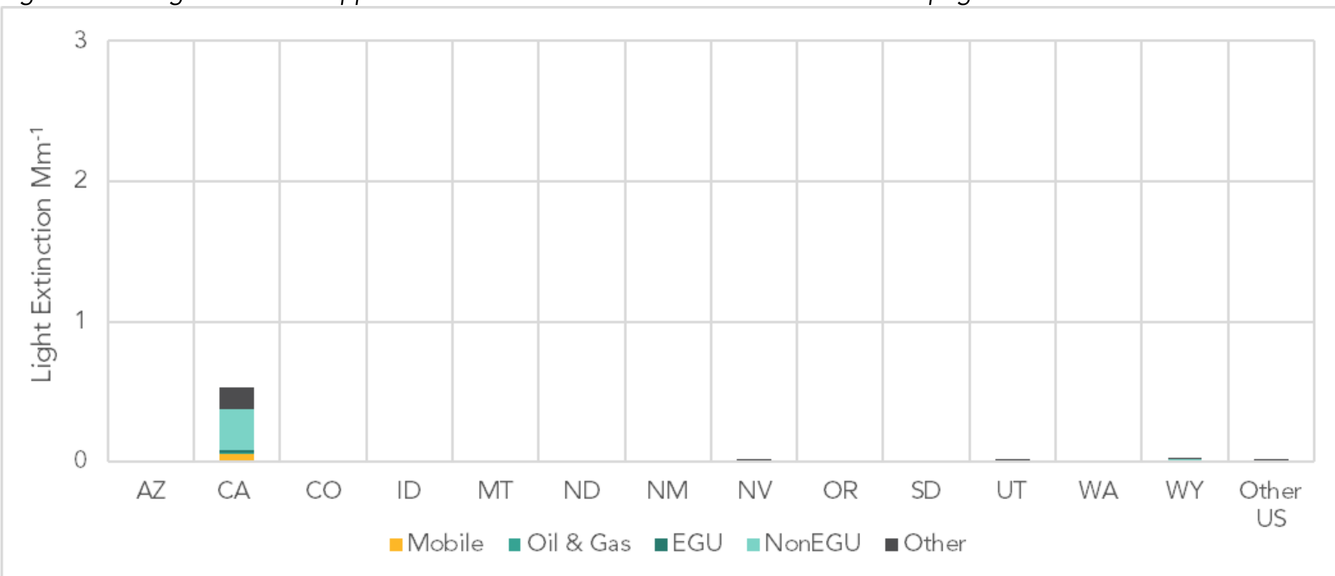
Regional source apportionment projections are shown in Figure C-88. California mobile sources are projected to be the largest regional source of ammonium nitrate in 2028. These results suggest that California's continued focus on reducing NOx emissions from mobile sources will be an effective means to improve visibility in these Class I areas.

Figure C-88: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at SEQU1



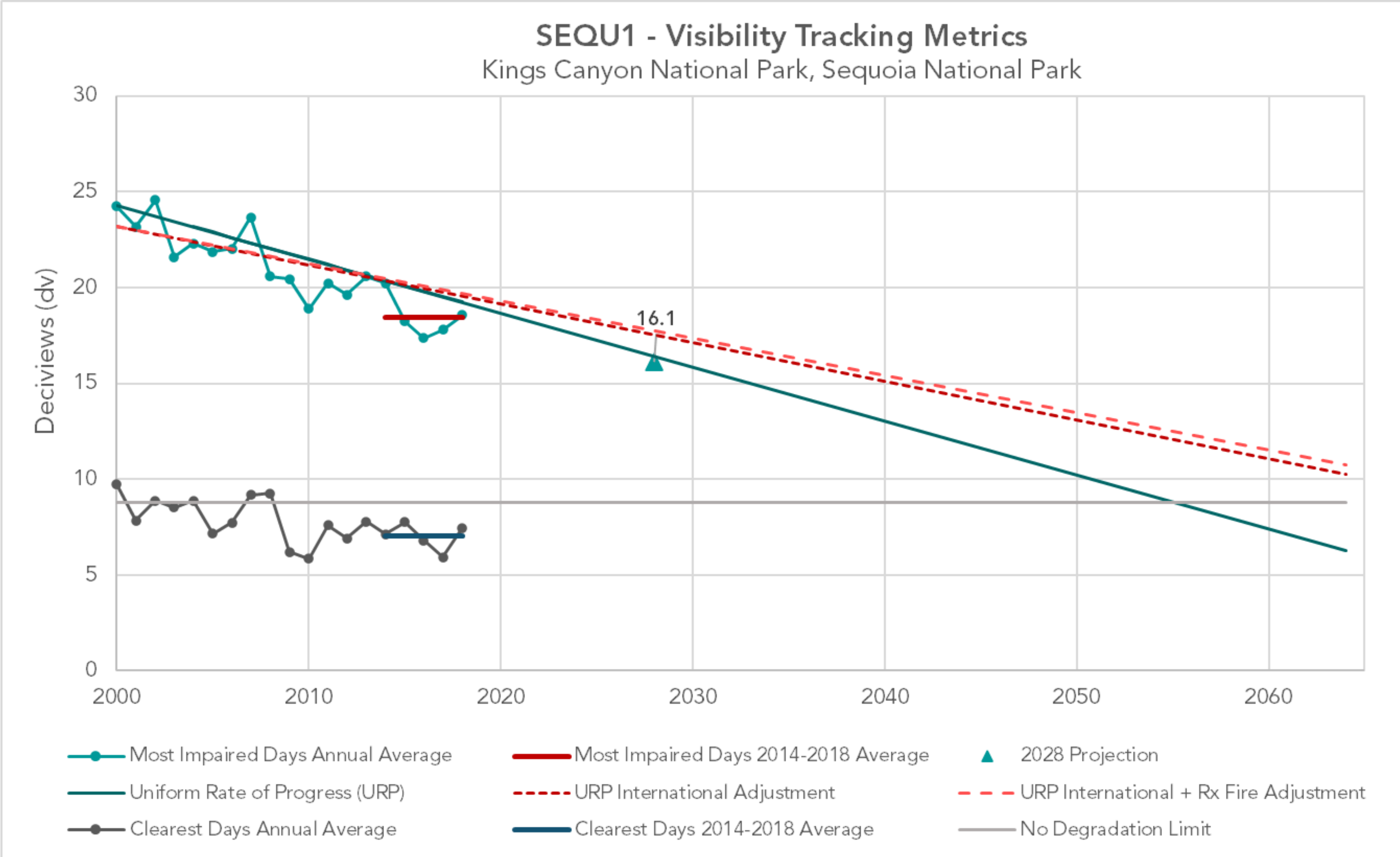
As shown in Figure C-89, light extinction from ammonium sulfate is projected to be less than a quarter of light extinction from ammonium nitrate. California's long-term strategy for regional haze is focused on reducing NOx emissions from mobile sources. Projections indicate that this strategy will lead to visibility benefits for Kings Canyon and Sequoia National Parks.

Figure C-89: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at SEQU1



The current and projected visibility tracking metrics for Kings Canyon and Sequoia National Parks are shown in Figure C-90. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 16.1 dv, which is comparable to a visual range of 48 miles (78 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating that the progress occurring in this area is on track to meet 2064 visibility targets.

Figure C-90: Visibility Tracking Metrics and Projections for Kings Canyon and Sequoia National Parks



San Rafael Wilderness Area (RAFA1) IMPROVE Monitoring Site

The RAFA1 monitoring site, shown in Figure C-91, is located near the southwestern border of the San Rafael Wilderness Area at 3,136 feet (956 m) asl. The monitoring site was established in February 2000, just south of the Figueroa Forest Service Ranger Station. The Figueroa Off Highway Vehicle Recreation Area is northeast of the site, as well as four developed family campgrounds: Figueroa (33 sites), Davy Brown (13 sites), Nira (12 sites), and Cachuma (7 sites). Data collected at the RAFA1 site are representative of visibility conditions at the San Rafael Wilderness Area.

Figure C-91: Photograph looking west towards the RAFA1 monitoring site

Photograph: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

The San Rafael Wilderness Area spans 142,722 acres in the South Central Coast Air Basin. Situated primarily within the southern portion of the Coastal Range, rugged chaparral covered hills and grassy meadows characterize much of the landscape.

As shown in Table C-12, visibility impairment on the clearest days during the baseline period was 6.5 dv. Visibility impairment on the clearest days decreased by 1.6 dv between the baseline and the current periods. During the current period, visibility impairment 4.9 dv, which is equivalent to a visual range of 148 miles (239 km).

Visibility impairment on the most impaired days during the baseline period was 17.3 dv. Visibility impairment on the most impaired days decreased by 3.2 dv between the baseline and the current periods. During the current period, visibility impairment was 14.1 dv, which is equivalent to a visual range of 59 miles (95 km). The rate of progress at this site between the baseline and current periods averaged 0.23 dv per year, which is faster than both the URP and adjusted URP.

Table C-12: Visibility Tracking Metrics for RAFA1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	6.5	4.9	1.8	1.6 dv	3.1 dv	--	--
Most Impaired	17.3	14.1	6.8	3.2 dv	7.3 dv	0.18 dv/year (0.14 dv/year)	0.23 dv/year

Monitoring data, shown in Figures C-92 and C-93, indicate that on the clearest and most impaired days ammonium sulfate accounts for the largest share of light extinction at the RAFA1 monitoring site. The low sulfur diesel regulations adopted in California have led to decreased sulfur emissions from mobile sources and subsequently decreased sulfate particles. Between the baseline and current periods, light extinction from ammonium sulfate decreased by 37 percent on the clearest days and by 43 percent on the most impaired days. On the most impaired days during the baseline period, ammonium nitrate accounted for the second largest portion of light extinction. Between the baseline and current periods, light extinction from ammonium nitrate decreased by 50 percent on the most impaired days.

Figure C-92: Average Extinction Composition for RAFA1 on the Clearest Days

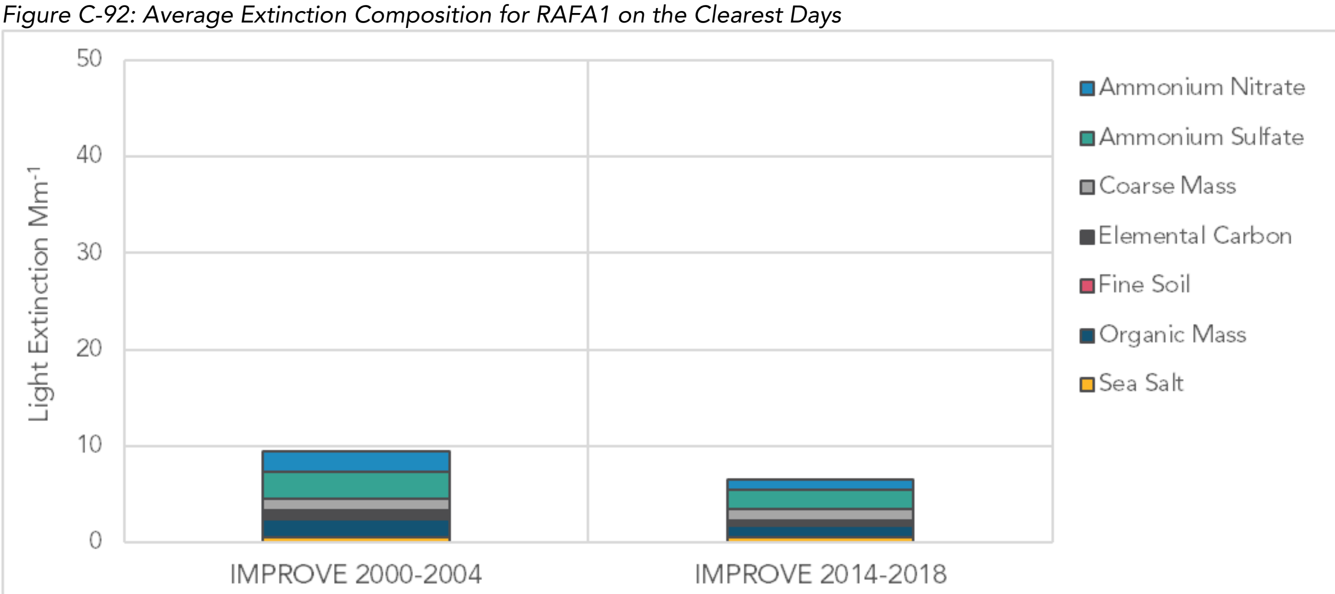
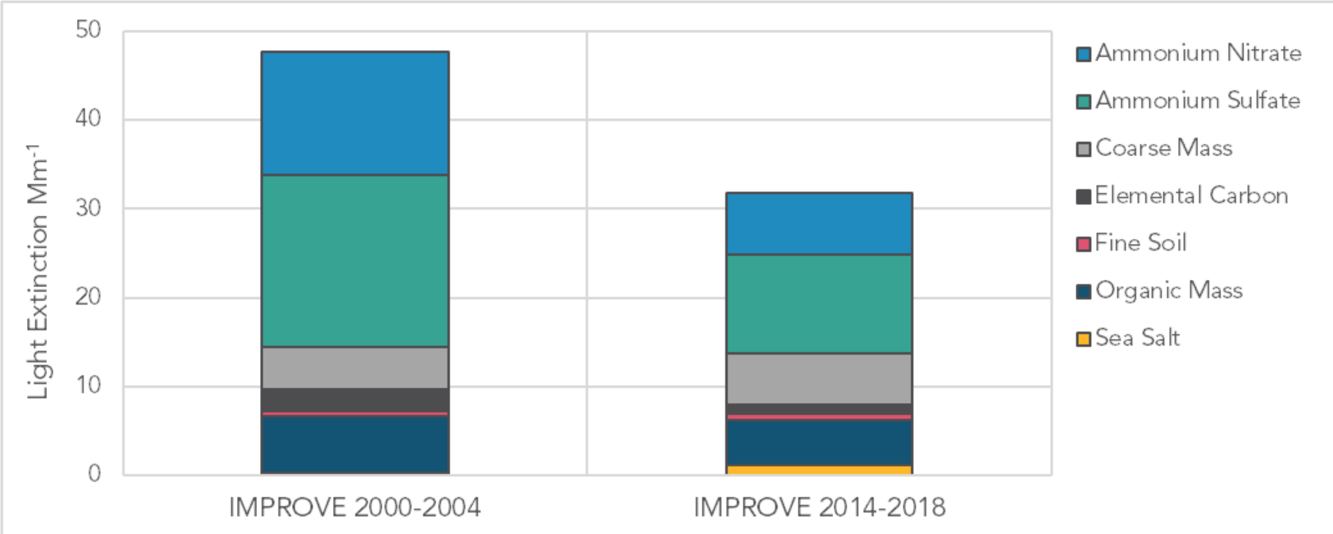
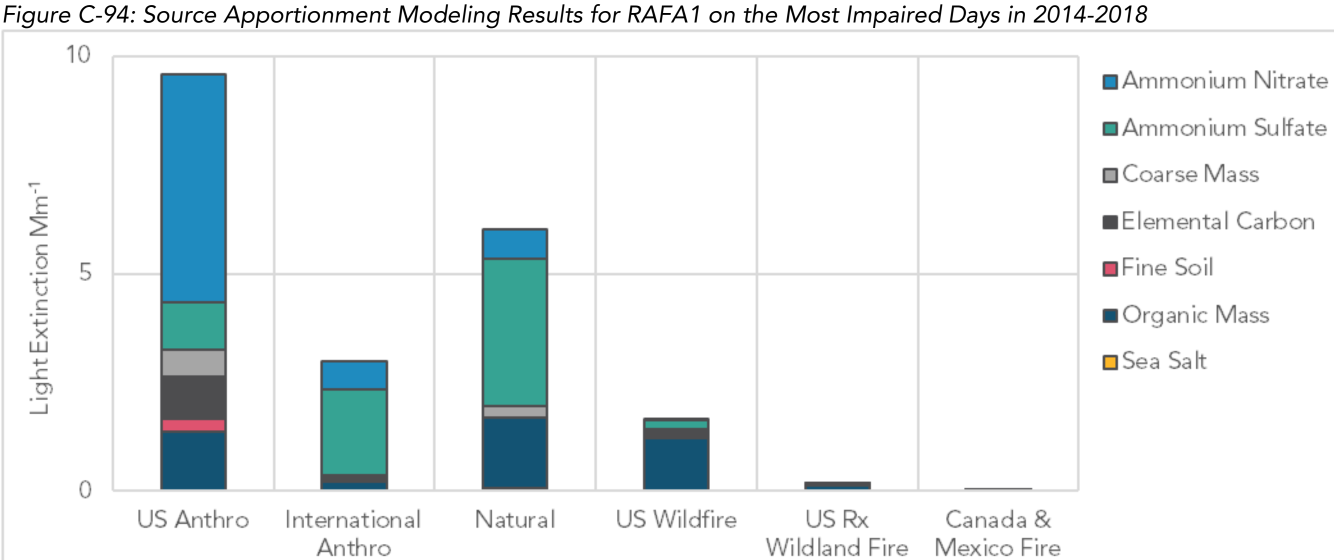


Figure C-93: Average Extinction Composition for RAFA1 on the Most Impaired Days



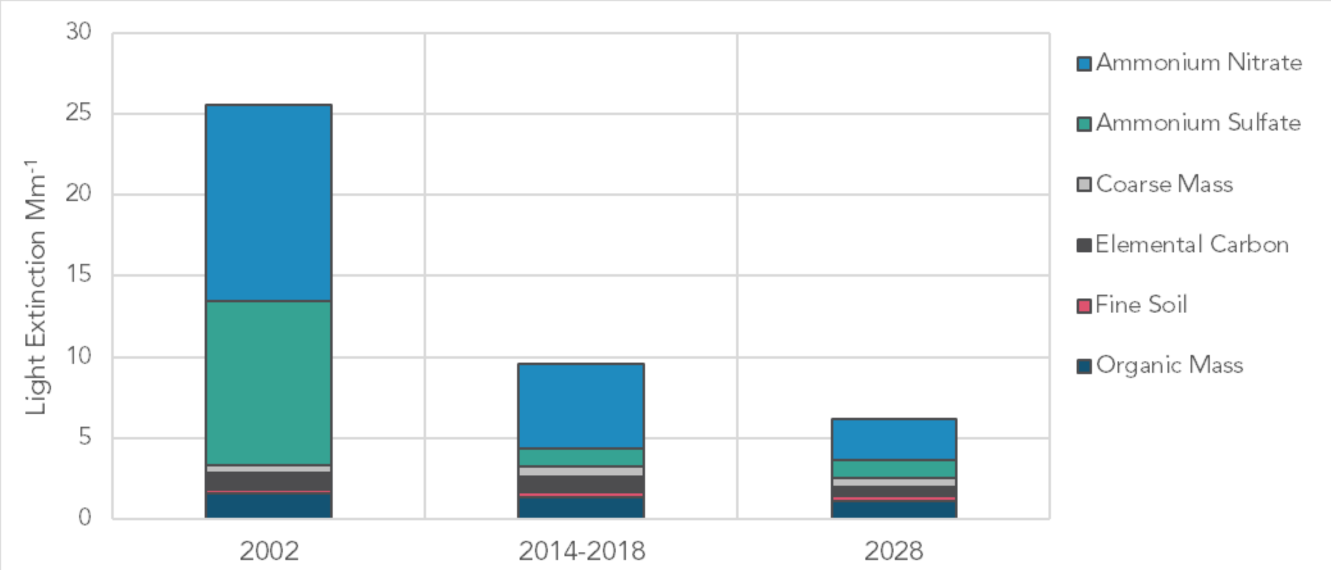
Source apportionment modeling, shown in Figure C-94, indicates most of the light extinction measured at the RAFA1 monitoring site is attributable to emissions from U.S. and natural sources. Emissions from international sources also contribute to visibility impairment on the most impaired days. Ammonium nitrate accounts for the largest share of light extinction attributable to U.S. sources and ammonium sulfate accounts for the largest share of light extinction attributable to international and natural sources.

Figure C-94: Source Apportionment Modeling Results for RAFA1 on the Most Impaired Days in 2014-2018



As shown in Figure C-95, light extinction attributable to U.S. sources has decreased substantially, largely due to controls focused on sulfur and NOx emissions. Projections show that between the current period and 2028, adopted emission controls are expected to reduce light extinction attributable to ammonium nitrate by an additional 52 percent.

Figure C-95: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at RAFA1 on the Most Impaired Days



Regional source apportionment modeling results are shown in Figures C-96 and C-97. These results indicate that California mobile sources are projected to account for the largest share of light extinction attributable to ammonium nitrate in 2028. Light extinction attributable to U.S. sources from ammonium nitrate is expected to be more than two times greater than light extinction from ammonium sulfate. California's long-term strategy for regional haze is focused on improving visibility through reduction of NOx emissions from mobile sources. This strategy is projected to yield visibility improvements for the San Rafael Wilderness Area.

Figure C-96: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at RAFA1

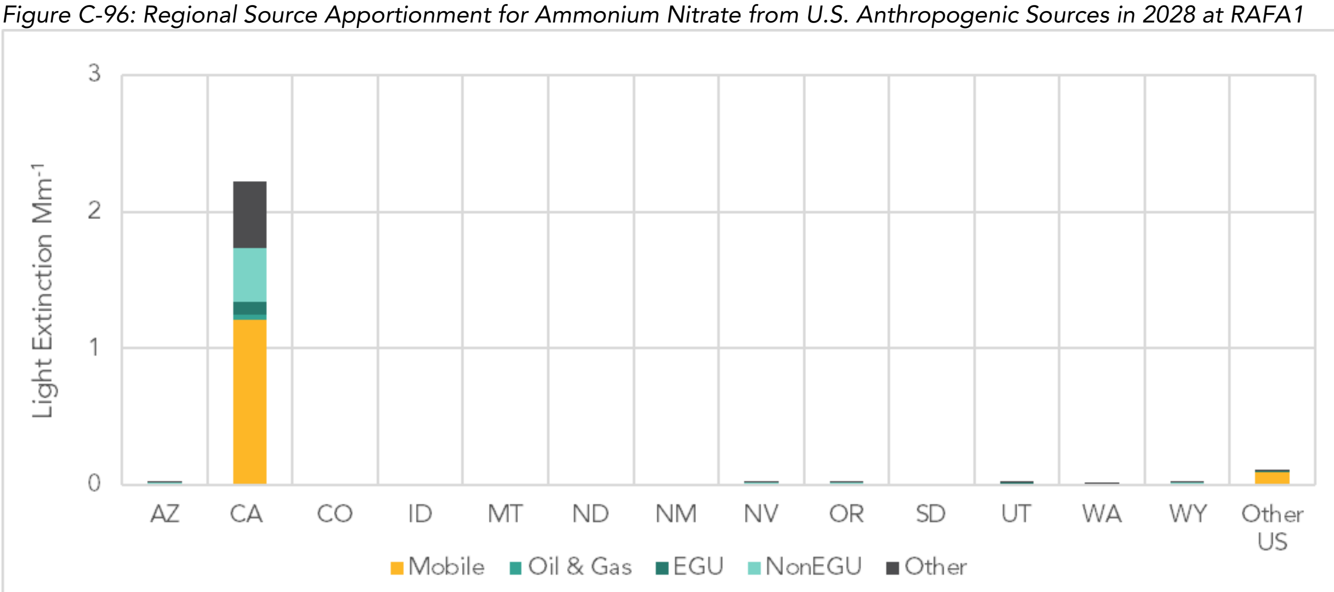
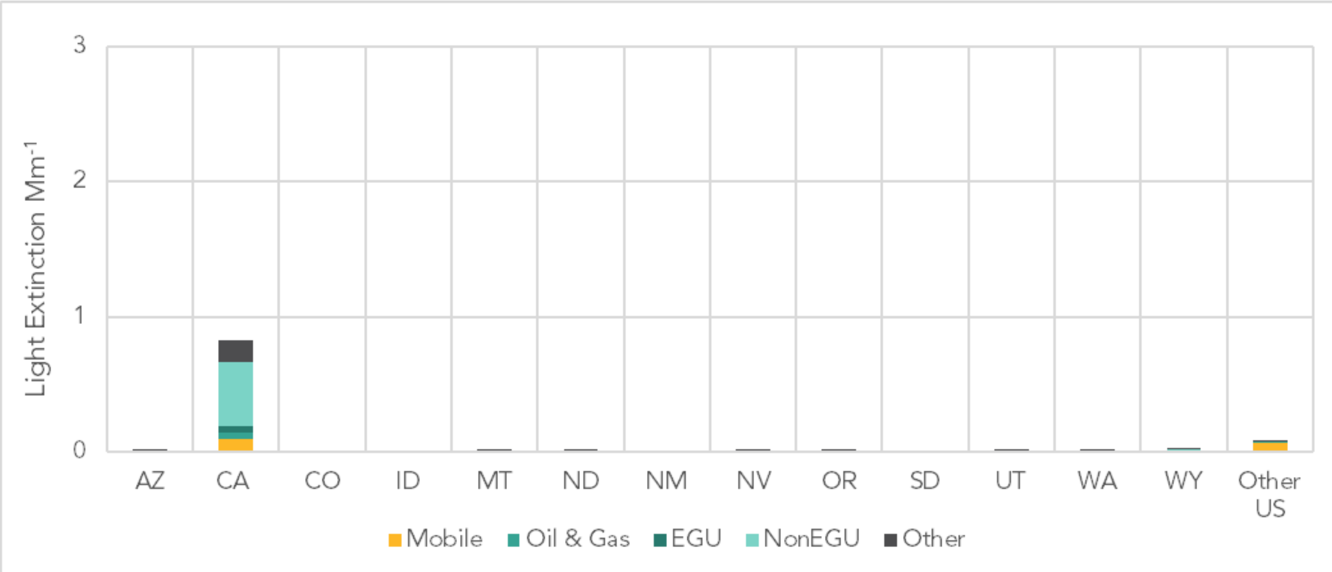
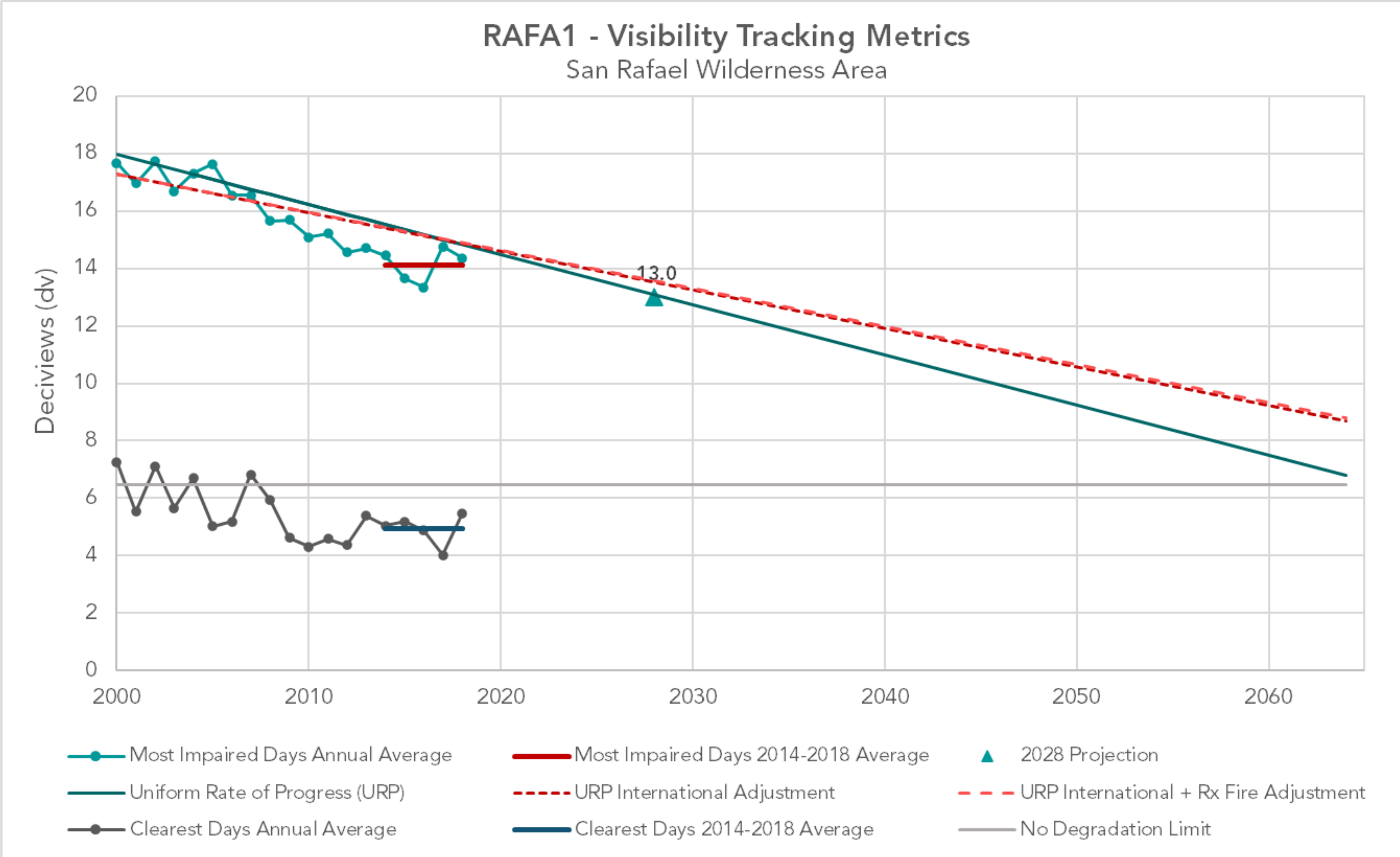


Figure C-97: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at RAFA1



The current and projected trends in visibility tracking metrics for the San Rafael Wilderness Area are shown in Figure C-98. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 13.0 dv in 2028, which corresponds to a visual range of 66 miles (106 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating that the rate of progress occurring in this area is on track to meet 2064 visibility targets.

Figure C-98: Visibility Tracking Metrics and Projections for San Rafael Wilderness Area



Southern California

Southern California's population is concentrated in the coastal areas. More than 40 percent of California's population resides in the South Coast Air Basin. Nearly half of the residents in the San Diego County Air Basin live within the City of San Diego. The Salton Sea Air Basin's largest city is Indio, which has a population of about 90,000 people but draws in more than one million visitors annually to a wide range of music, food, and art festivals. The largest cities in the Mojave Desert Air Basin include Lancaster, Palmdale, and Victorville, which are located just north of the South Coast Air Basin. The rest of the Mojave Desert Air Basin is sparsely populated. Emissions from urban areas contribute to visibility impairment at Class I areas in the Southern California region.

The movement of goods and people is a significant source of emissions in Southern California. The sea ports of Los Angeles and Long Beach, which are the busiest in North America, are in the South Coast Air Basin and the Port of San Diego is in the San Diego County Air Basin. Networks of highways, city streets, and rail lines are common features on the landscape.

Emissions from the South Coast Air Basin account for most of the Southern California region's emissions. In 2014, emissions from the South Coast Air Basin accounted for 61 percent of NOx emissions in the Southern California region. Mobile sources are the dominant NOx emission source sector in each air basin, and overall accounted for 82 percent of the region's NOx emissions in 2014.

Terrain and prevailing meteorological conditions play a predominant role in the transport of emissions in Southern California. Emission sources are generally concentrated in the western portion of the region. The sea-breeze circulation along the coast provides a mechanism to temper transport but also recirculate emissions in the coastal areas. Prevailing winds transport emissions inland. Mountainous terrain provides a physical barrier to trap pollutants and mountain passes provide a conduit to route emissions inland.

Five IMPROVE monitoring sites are in the Southern California region. From north to south, the monitoring sites in this region are in or near the Domeland Wilderness Area, San Gabriel Wilderness Area, San Gorgonio Wilderness Area, Joshua Tree National Park, and Agua Tibia Wilderness Area. The following section provides an overview of the monitoring sites and their associated Class I areas, visibility monitoring data, and source apportionment for each location.

Domeland Wilderness Area (DOME1) IMPROVE Monitoring Site

The DOME1 monitoring site, shown in Figure C-99, is located at 3,041 feet (927 m) asl near the southeast portion of the Domeland Wilderness Area. The monitoring site was established in February 2000 adjacent to California's State Route 178. Data collected at this site are representative of visibility conditions in the Domeland Wilderness Area.

Figure C-99: Photograph looking northeast towards DOME1 Monitoring Site

Photograph Source: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

The Domeland Wilderness Area includes 62,206 acres of semi-arid terrain. The landscape is covered in pinyon pine, juniper, and sagebrush that is interrupted by numerous outcrops of the area's namesake granite domes. Elevation ranges from 3,000 to 9,730 feet (914 to 2,966 m) asl. The northern portion of the Domeland Wilderness Area is within the San Joaquin Valley Air Basin. The southern portion and the IMPROVE monitoring site are within the Mojave Desert Air Basin.

As shown in Table C-13, visibility impairment on the clearest days during the baseline period was 5.1 dv. Visibility impairment on the clearest days decreased by 0.7 dv between the baseline and the current periods. During the current period, visibility impairment was 4.4 dv, which is comparable to a visual range of 156 miles (251 km).

Visibility impairment on the most impaired days during the baseline period was 17.2 dv. On the most impaired days, visibility impairment decreased by 2.1 dv between the baseline and the current periods. During the current period, visibility impairment was 15.1 dv, which is comparable to a visual range of 54 miles (86 km). Progress between the baseline and current periods averaged 0.15 dv per year, which is faster than the URP adjusted to account for international emissions and prescribed fire.

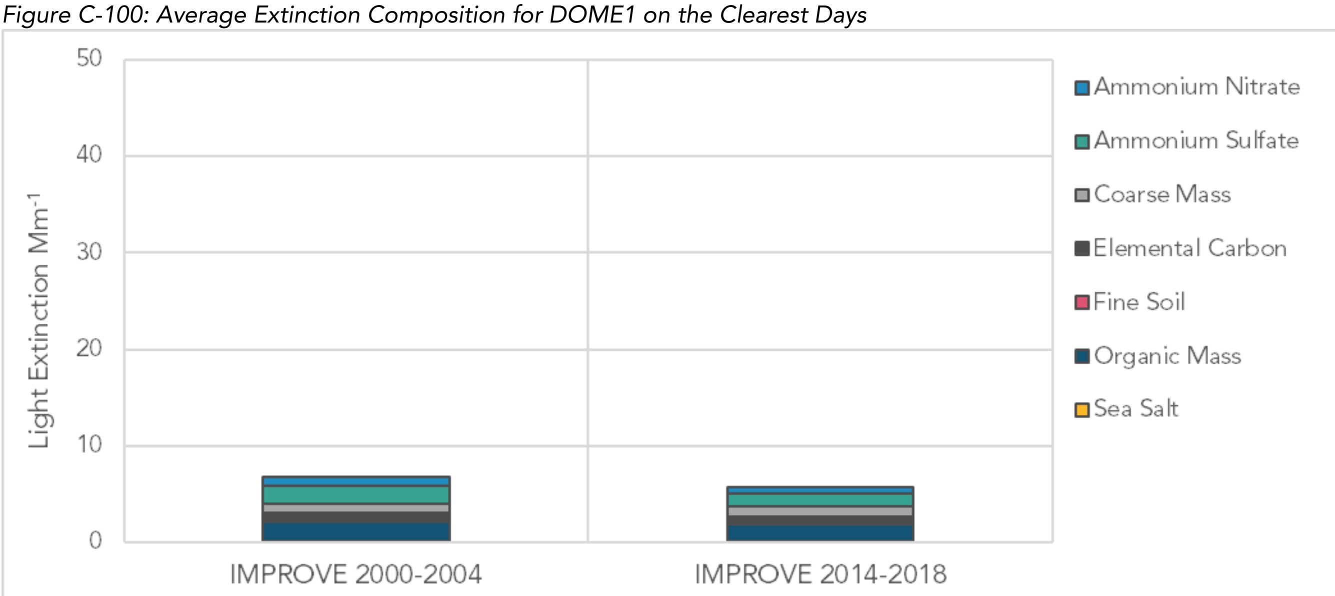
Table C-13: Visibility Tracking Metrics for DOME1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress

Clearest	5.1	4.4	1.2	0.7 dv	3.2 dv	--	--
Most Impaired	17.2	15.1	6.2	2.1 dv	8.9 dv	0.18 dv/year (0.13 dv/year)	0.15 dv/year

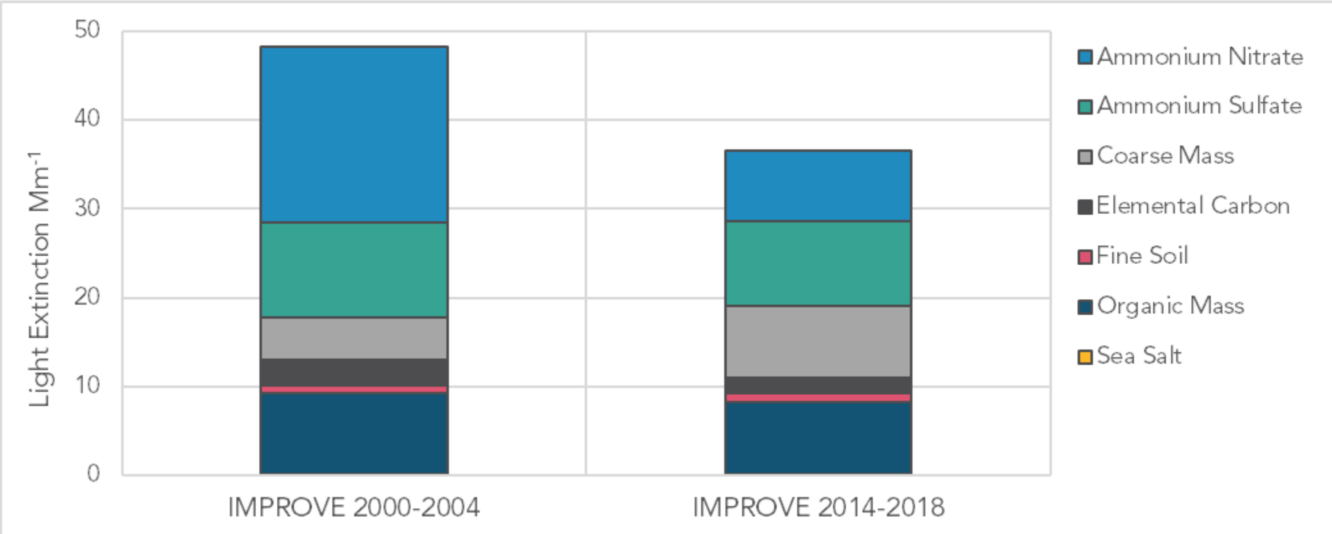
Monitoring data, shown in Figures C-100, indicate that on the clearest days, ammonium sulfate and organic mass account for the largest portion of light extinction at the DOME1 monitoring site. Between the baseline period and the current period, light extinction from ammonium sulfate decreased by 27 percent and light extinction from organic mass decreased by 11 percent on the clearest days.

Figure C-100: Average Extinction Composition for DOME1 on the Clearest Days



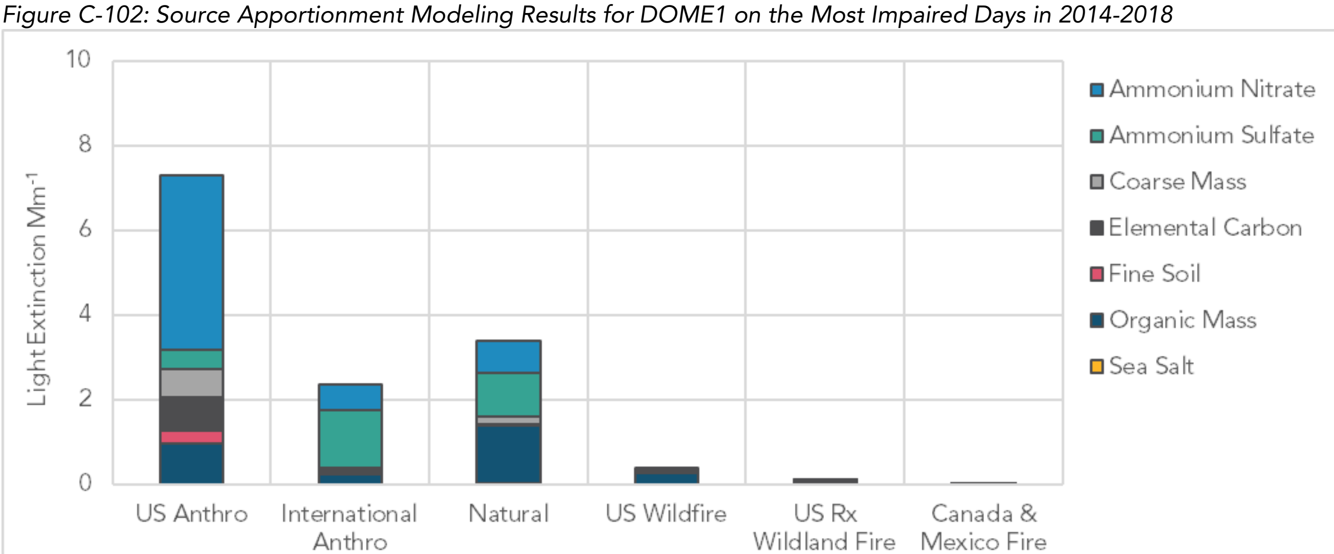
As shown in Figure C-101, ammonium nitrate accounted for the largest portion of light extinction on the most impaired days during the baseline period. Between the baseline period and the current period, the amount of light extinction attributed to ammonium nitrate decreased 60 percent. During the current period, ammonium nitrate, ammonium sulfate, coarse mass and organic mass contributed to visibility impairment on the most impaired days.

Figure C-101: Average Extinction Composition for DOME1 on the Most Impaired Days



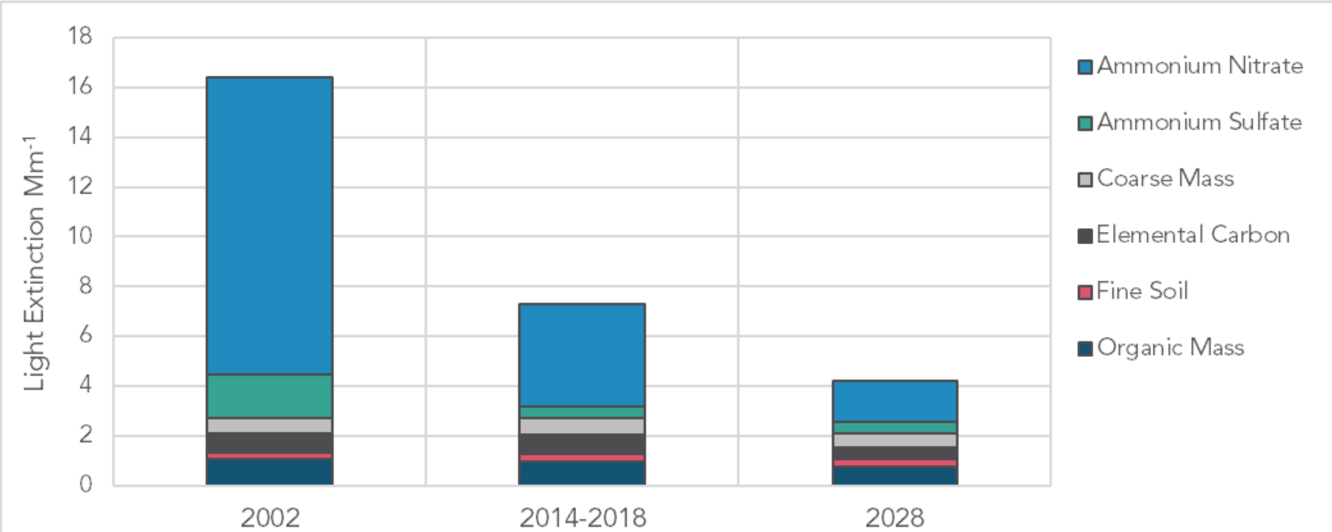
Source apportionment modeling, shown in Figure C-102, indicates that emissions from U.S. sources account for the largest share of light extinction on the most impaired days at the DOME1 monitoring site. Emissions from natural and international sources also contribute to light extinction on the most impaired days. The portion of light extinction attributed to U.S. sources is dominated by ammonium nitrate. Ammonium sulfate accounts for the largest share of light extinction attributable to international sources and organic mass accounts for the largest share of the light extinction attributed to natural sources.

Figure C-102: Source Apportionment Modeling Results for DOME1 on the Most Impaired Days in 2014-2018



As shown in Figure C-103, ammonium nitrate is the dominant species in the portion of light extinction attributable to U.S. sources. The decreasing impact of ammonium nitrate on light extinction on the most impaired days is reflective of ongoing efforts to reduce NOx emissions in California. Between the current period and 2028, the amount of light extinction from ammonium nitrate is projected to decrease by an additional 59 percent, signaling that emission control strategies are reducing visibility reducing PM in this Class I area.

Figure C-103: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at DOME1 on the Most Impaired Days



The results of regional source apportionment modeling projections are shown in Figures C-104 and C-105. These results indicate that California mobile sources will continue to be the largest regional source of ammonium nitrate in 2028. The portion of light extinction from ammonium nitrate attributable to regional sources is more than four times larger than from ammonium sulfate. These results suggest that continued efforts focused on reducing emissions from the mobile source sector will continue to benefit visibility in the Domeland Wilderness Area.

Figure C-104: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at DOME1

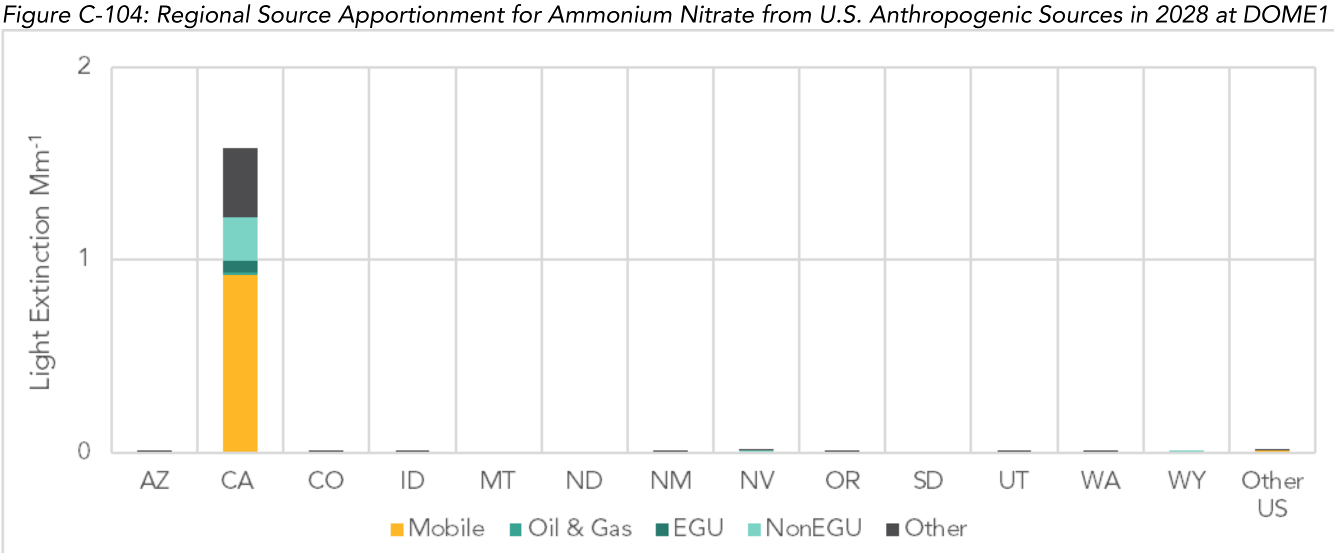
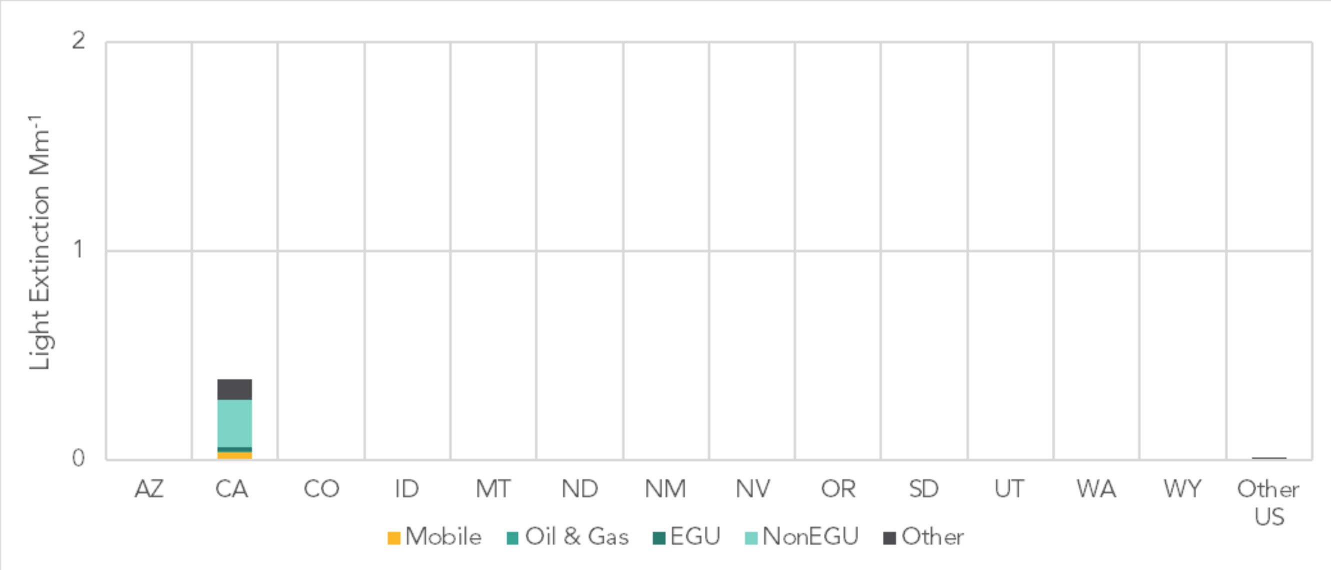
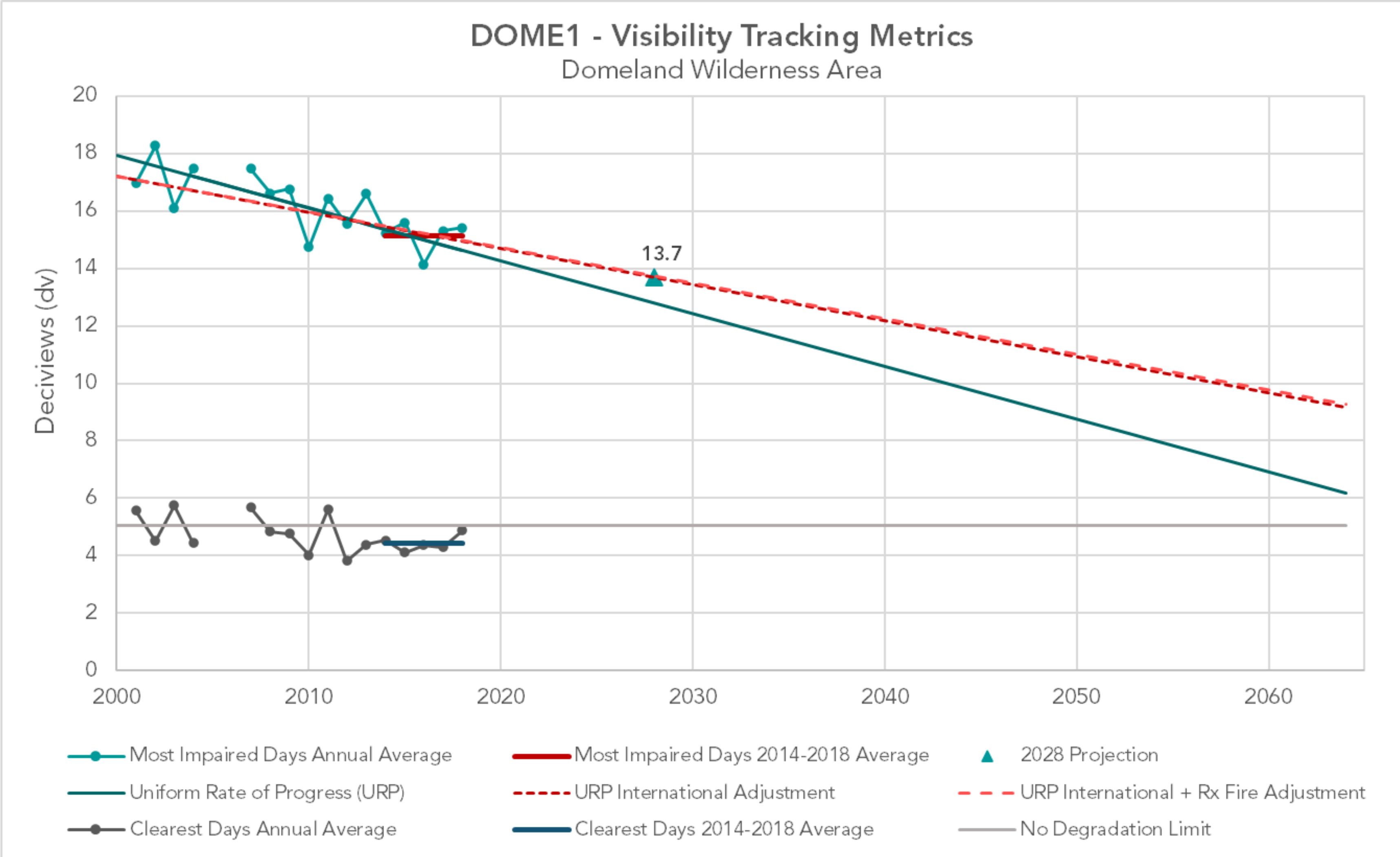


Figure C-105: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at DOME1



The current and projected trends for visibility tracking metrics in the Domeland Wilderness Area are shown in Figure C-106. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 13.7 dv in 2028, which represents a visual range of 62 miles (99 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating that this area is on track to reach 2064 visibility targets.

Figure C-106: Visibility Tracking Metrics and Projections for Domeland Wilderness Area



San Gabriel Wilderness Area (SAGA1) IMPROVE Monitoring Site

The SAGA1 monitoring site, shown in Figure C-107, is on the west side of the San Gabriel Wilderness Area at 5,876 feet (1791 m) asl, adjacent to the Vetter Mountain Fire Lookout. The monitoring site was established in December 2001. Data collected at this site are representative of visibility conditions in the Cucamonga and San Gabriel Wilderness Areas.

Figure C-107: Photograph looking south toward the SAGA1 monitoring site

Photograph: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

The Cucamonga and San Gabriel Wilderness Areas span 9,022 acres and 36,137 acres, respectively. The landscape of the low elevation portion of the San Gabriel Wilderness Area is characterized by dense chaparral. The higher elevations of the San Gabriel and Cucamonga Wilderness Areas have dense fir and pine stands. More than 15 million people live within a 90-minute drive of these wilderness areas and both are very heavily used. The San Gabriel and Cucamonga Wilderness Areas are in the South Coast Air Basin. Emissions from the adjacent urban areas contribute to visibility impairment.

As shown in Table C-14, visibility impairment on the clearest days during the baseline period was 4.8 dv. Visibility impairment on the clearest days decreased by 2.6 dv between the baseline and the current periods. During the current period, visibility impairment was 2.8 dv, which is comparable to a visual range of 183 miles (295 km).

Visibility impairment on the most impaired days during the baseline period was 17.9 dv. Between the baseline and current periods, visibility impairment on the most impaired days decreased by 4.7 dv. During the current period, visibility impairment was 13.2 dv, which is comparable to a visual range of 65 miles (104 km). The average rate of progress between the baseline and current periods was 0.34 dv per year. This rate is faster than the URP and double the adjusted URP.

Table C-14: Visibility Tracking Metrics for SAGA1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	4.8	2.8	0.4	2.0 dv	2.4 dv	--	--
Most Impaired	17.9	13.2	6.1	4.7 dv	7.1 dv	0.20 dv/year (0.17 dv/year)	0.34 dv/year

Monitoring data, shown in Figures C-108 and C-109, indicate that ammonium nitrate and ammonium sulfate account for the largest portion of light extinction on the clearest days and the most impaired days at the SAGA1 monitor. Between the baseline period and the current period, light extinction from ammonium nitrate decreased by 55 percent on the clearest days and 64 percent on the most impaired days. Light extinction from ammonium sulfate decreased by 35 percent on the clearest days and by 25 percent on the most impaired days.

Figure C-108: Average Extinction Composition for SAGA1 on the Clearest Days

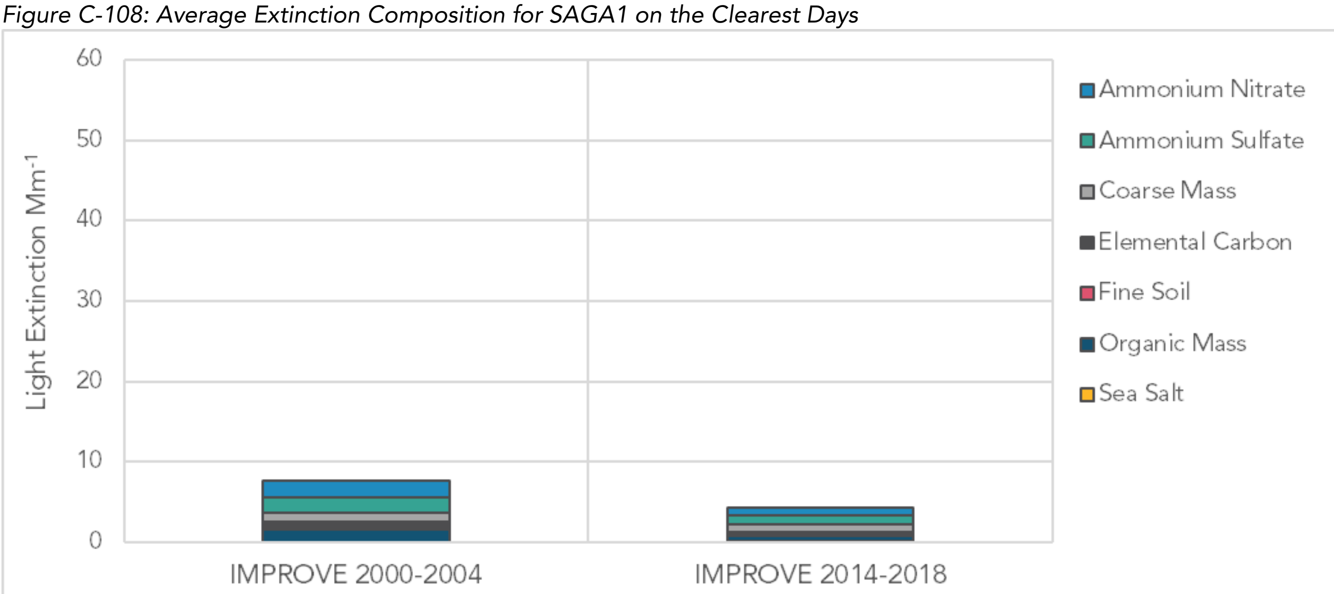
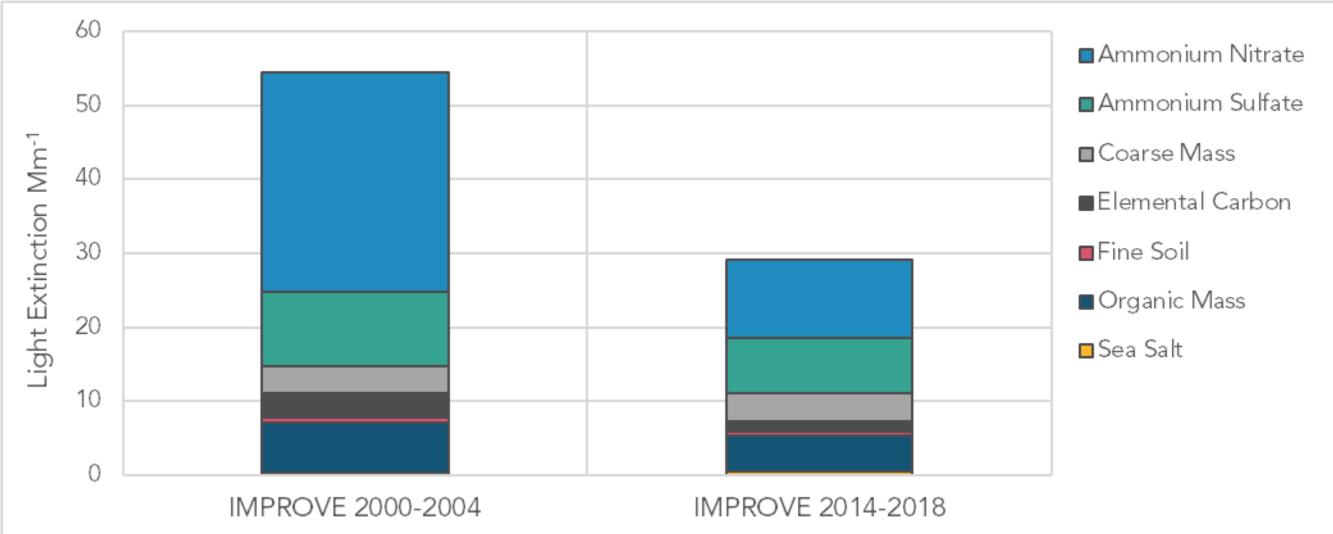
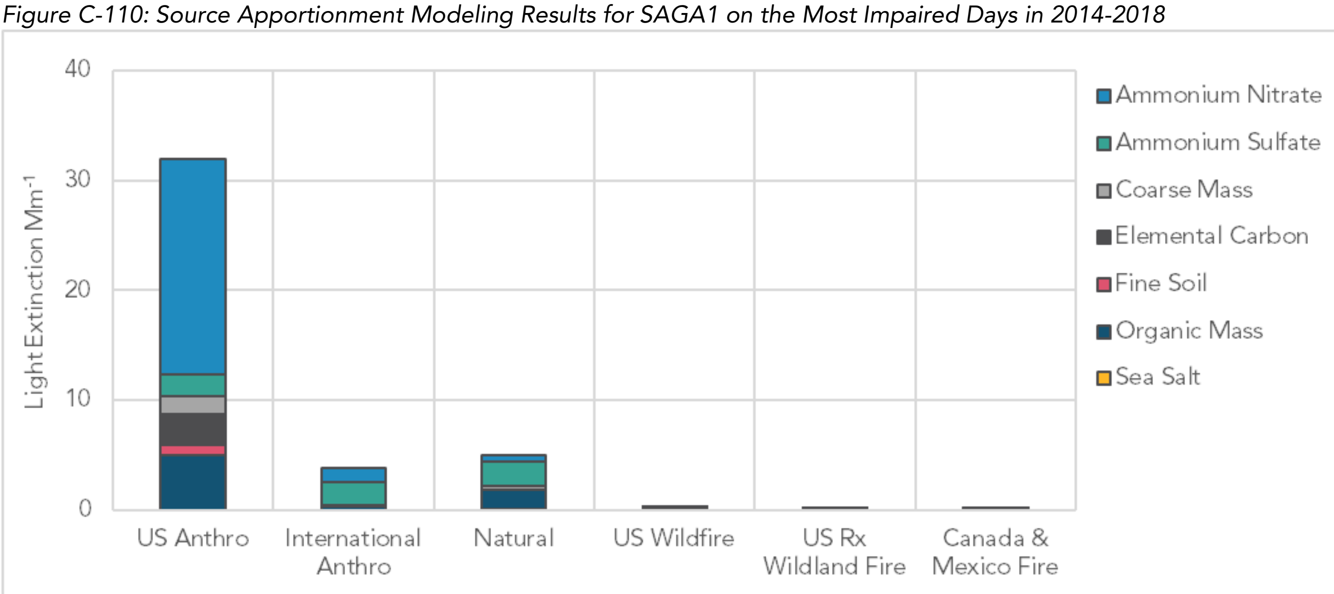


Figure C-109: Average Extinction Composition for SAGA1 on the Most Impaired Days



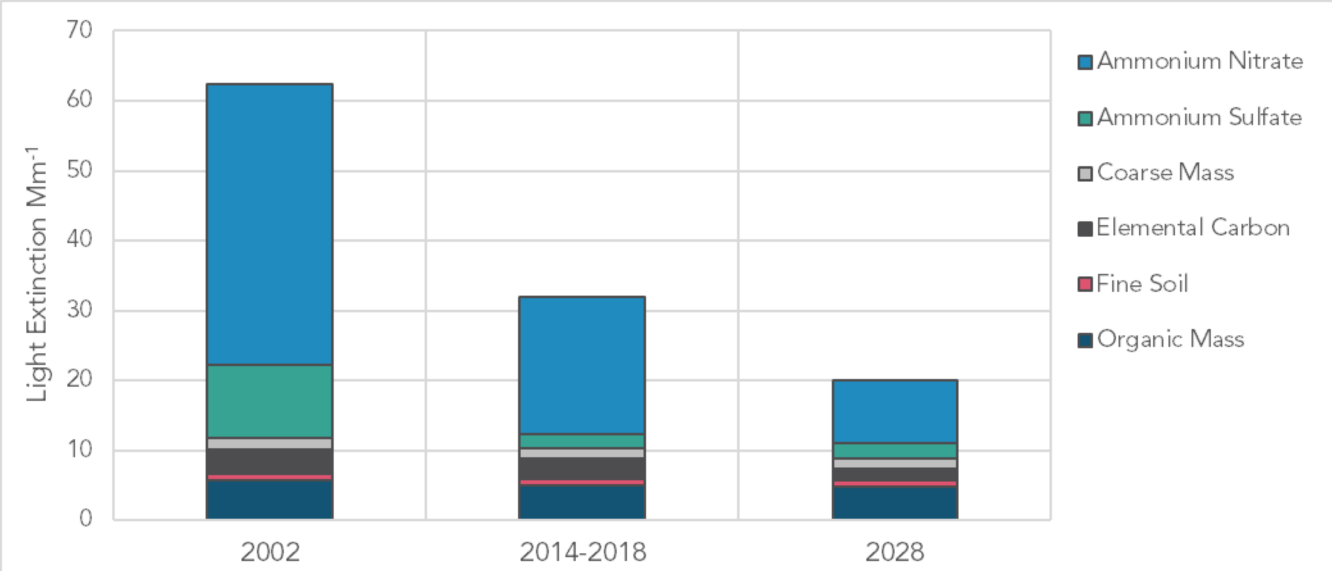
Source apportionment modeling, shown in Figure C-110, indicates that U.S. emissions account for the largest portion of light extinction measured at the SAGA1 monitoring site. Emissions from natural and international sources also contribute to visibility impairment. Ammonium nitrate accounts for the majority of light extinction attributable to U.S. sources; whereas ammonium sulfate accounts for the majority of light extinction attributable to international and natural sources.

Figure C-110: Source Apportionment Modeling Results for SAGA1 on the Most Impaired Days in 2014-2018



As shown in Figure C-111, ammonium nitrate attributable to U.S. sources is decreasing. Light extinction attributable to ammonium nitrate from U.S. sources is projected to decrease by an additional 54 percent on the most impaired days between the current period and 2028.

Figure C-111: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at SAGA1 on the Most Impaired Days



Regional source apportionment projections are shown in Figures C-112 and C-113. The portion of light extinction attributable to ammonium nitrate from regional sources is more than four times larger than light extinction attributable to ammonium sulfate from regional sources. California mobile sources account for the largest share of ammonium nitrate attributable to regional sources. Continued efforts to reduce emissions from this sector will continue to yield visibility improvements for the Cucamonga and San Gabriel Wilderness Areas.

Figure C-112: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at SAGA1

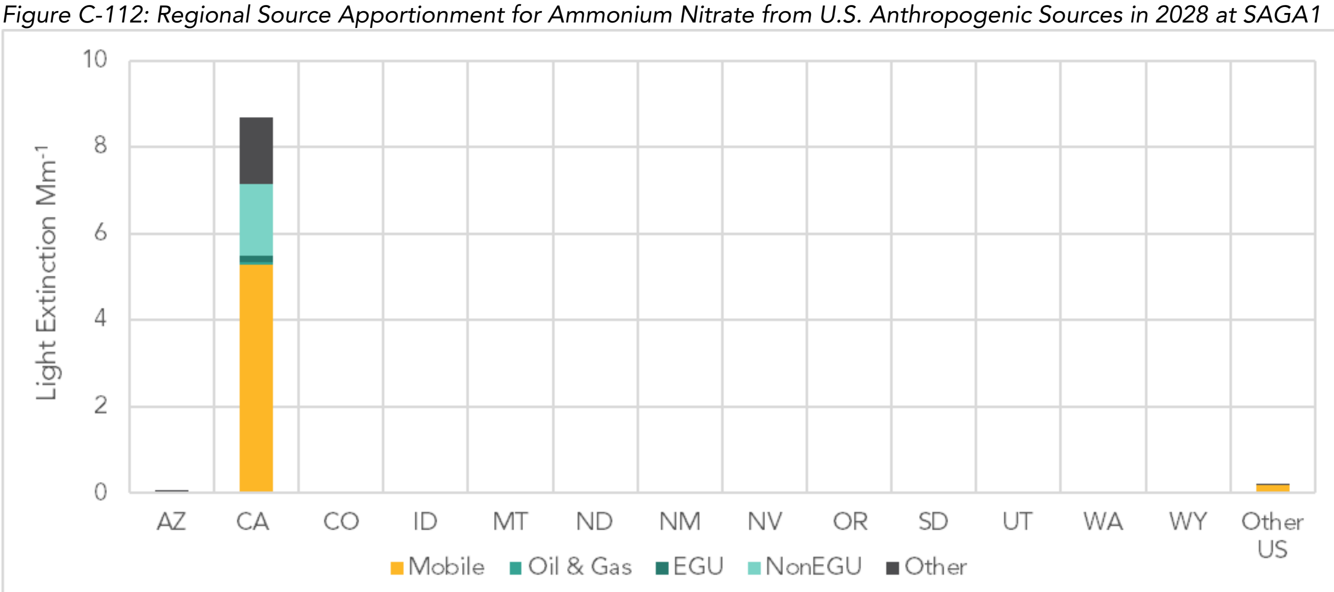
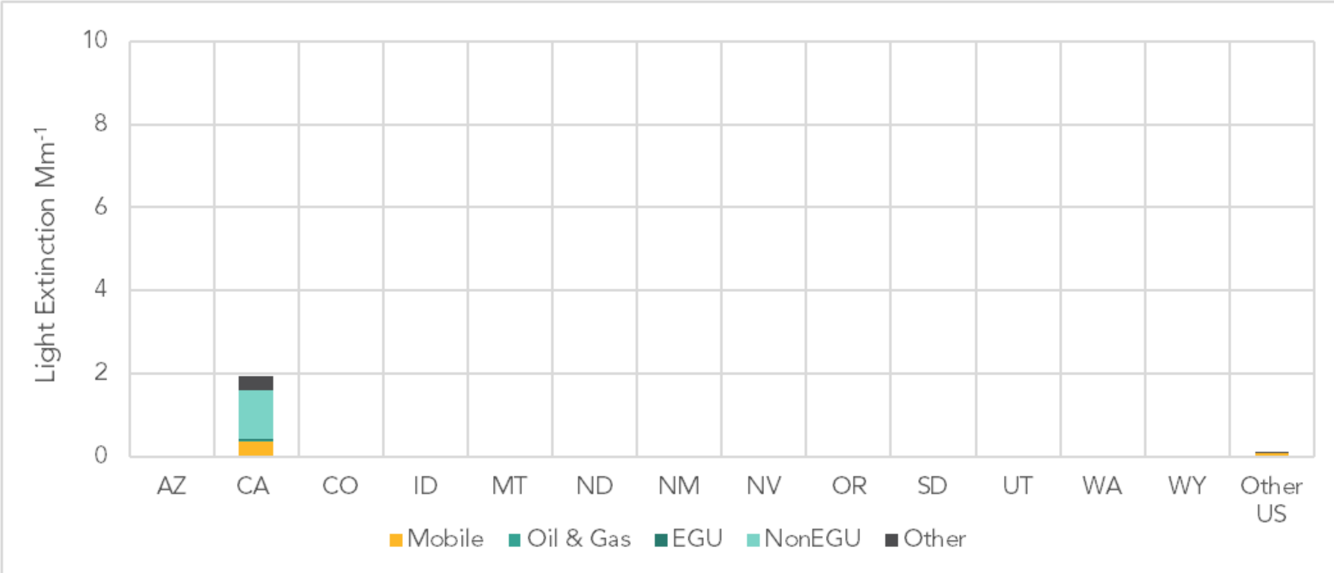
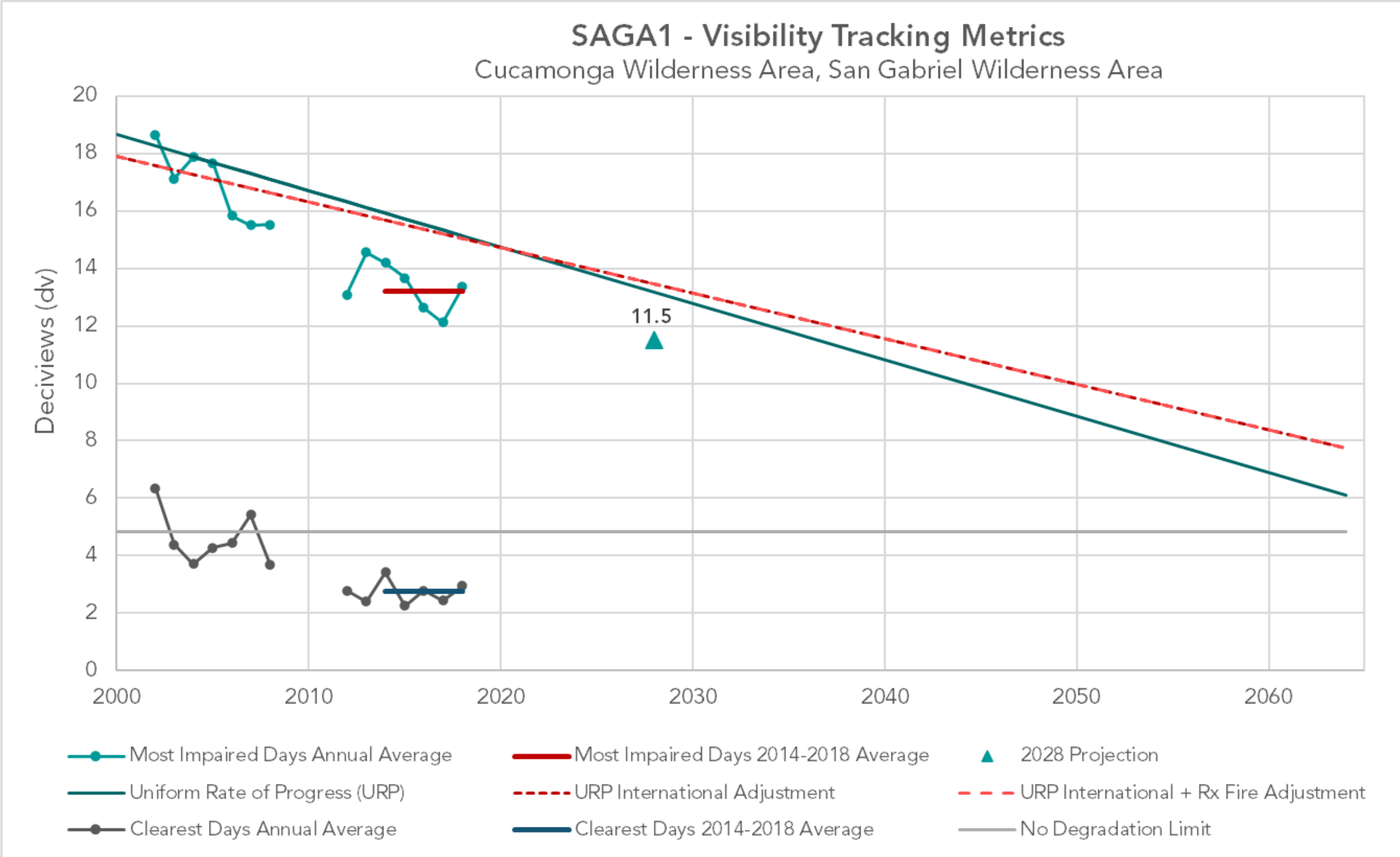


Figure C-113: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at SAGA1



The current and projected trends for visibility tracking metrics in the Cucamonga and San Gabriel Wilderness Areas are shown in Figure C-114. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility on the most impaired days is projected to be 11.5 dv in 2028, which represents a visual range of 77 miles (123 km). This 2028 projection is below the adjusted glidepath adjusted that accounts for international and wildland prescribed fire emissions, indicating that these areas are on track to meet 2064 visibility targets.

Figure C-114: Visibility Tracking Metrics and Projections for Cucamonga Wilderness Area and San Gabriel Wilderness Area



San Gorgonio Wilderness Area (SAGO1) IMPROVE Monitoring Site

The SAGO1 monitoring site, shown in Figure C-115, is located at 1,726 m asl near the northwest border of the San Gorgonio Wilderness Area. The monitoring site was established in March 1988 adjacent to the Converse Fire Station. The site is a couple of miles south of Big Bear Lake, a well-known recreational destination in southern California with ski areas and marinas. Data collected at the SAGO1 site are representative of visibility conditions in the San Gorgonio and San Jacinto Wilderness Areas.

Figure C-115: Photograph looking northwest toward the SAGO1 monitoring site

Photograph: http://vista.cira.colostate.edu/Improve/monitoring-site-browser/

The San Gorgonio Wilderness Area spans 34,644 acres. Terrain is forested and rugged with more than eleven peaks rising above 10,000 feet (3,048 m) asl. Like the San Gabriel and Cucamonga Wilderness Areas, the San Gorgonio Wilderness Area is in the South Coast Air Basin.

The San Jacinto Wilderness Area covers 20,564 acres. The northern portion is alpine terrain with dense pine stands. In contrast, the southern portion is high desert with dense chaparral. The San Jacinto Wilderness Area straddles the border of the South Coast and Salton Sea Air Basins. The San Gorgonio and San Jacinto Wilderness Areas are impacted by emissions from the upwind urban areas in the South Coast Air Basin.

As shown in Table C-15, visibility impairment on the clearest days during the baseline period was 5.4 dv. Visibility impairment on the clearest days decreased by 2.1 dv between the baseline and the current periods. During the current period, visibility impairment was 3.3 dv, which is comparable to a visual range of 174 miles (280 km).

Visibility impairment on the most impaired days during the baseline period was 20.4 dv. Between the baseline period and the current period, visibility impairment on the most impaired days decreased by 6.0 dv. During the current period, visibility impairment was 14.4 dv, which is equivalent to a visual range of 57 miles (92 km) in the San Gorgonio and San Jacinto Wilderness Areas. The rate of progress between the baseline and current periods amounted to an average of 0.43 dv per year. This rate is faster than the URP and more than double the adjusted URP.

Table C-15: Visibility Tracking Metrics for SAGO1

	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	5.4	3.3	1.2	2.1 dv	2.1 dv	--	--
Most Impaired	20.4	14.4	6.2	6.0 dv	8.2 dv	0.24 dv/year (0.20 dv/year)	0.43 dv/year

Monitoring data, shown in Figures C-116 and C-117, indicate that ammonium sulfate accounts for the largest portion of light extinction on the clearest days and ammonium nitrate accounts for the largest portion of light extinction on the most impaired days at the SAGO1 monitoring site. Between the baseline period and the current period, light extinction from ammonium sulfate decreased by 39 percent on the clearest days and light extinction from ammonium nitrate decreased by 68 percent on the most impaired days.

Figure C-116: Average Extinction Composition for SAGO1 on the Clearest Days

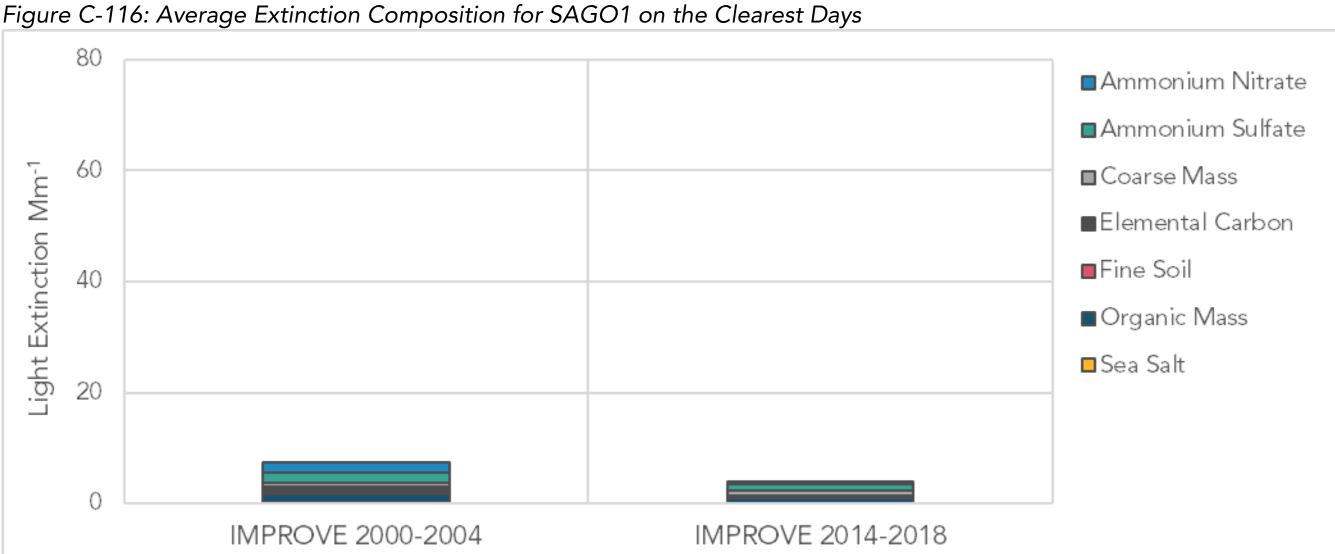
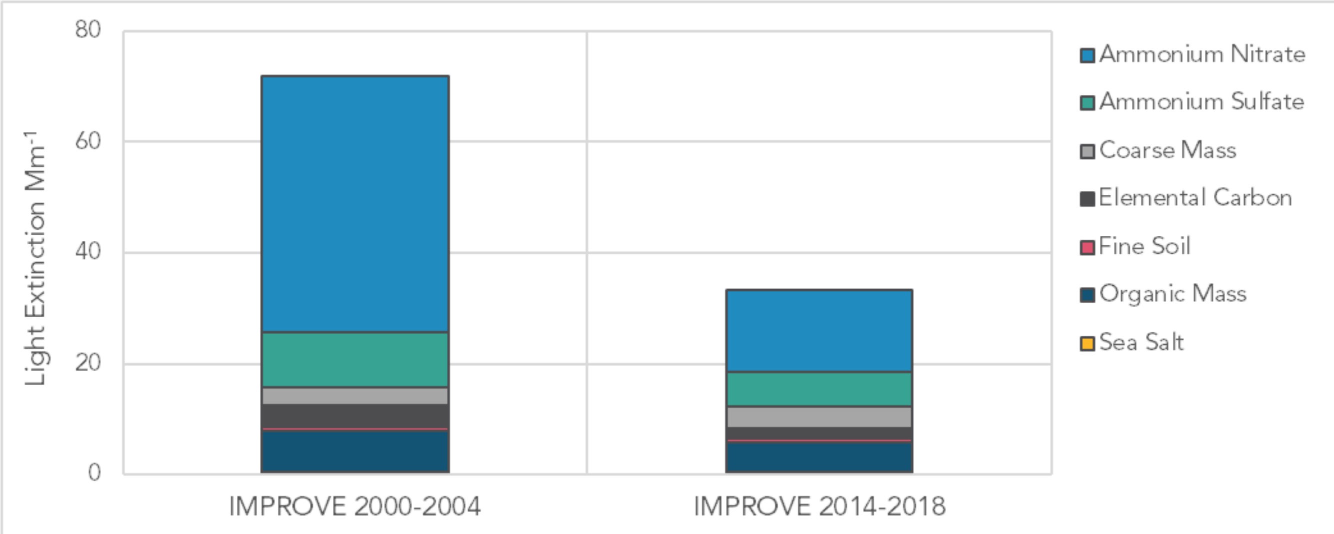
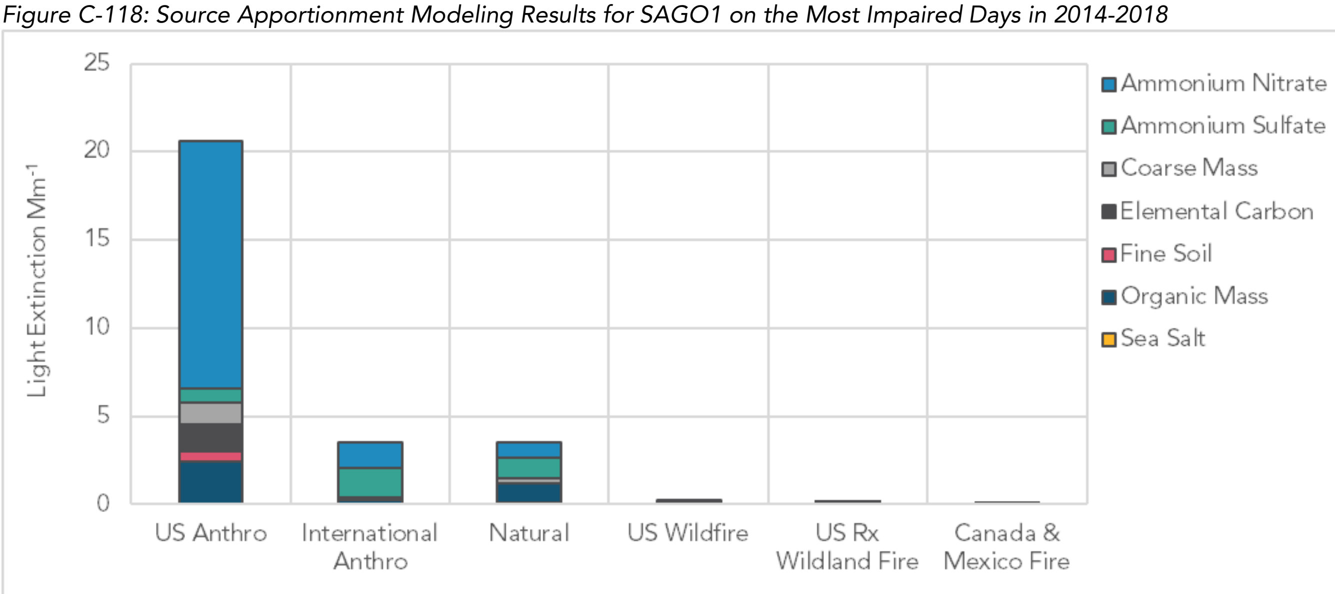


Figure C-117: Average Extinction Composition for SAGO1 on the Most Impaired Days



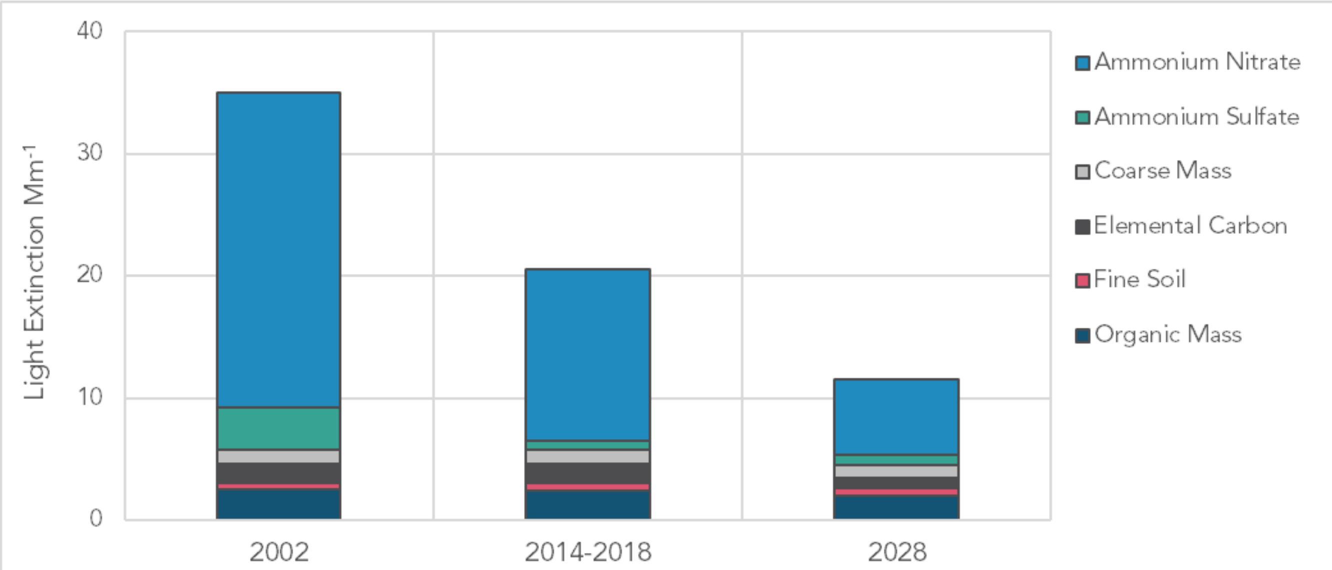
Source apportionment modeling, shown in Figure C-118, indicates that U.S. emissions account for the largest portion of light extinction on the most impaired days at the SAGO1 monitoring site. Emissions from international and natural sources also contribute to visibility impairment. Ammonium nitrate accounts for the largest portion of light extinction from U.S. sources and ammonium sulfate accounts for the largest portion of light extinction from the international and natural sources.

Figure C-118: Source Apportionment Modeling Results for SAGO1 on the Most Impaired Days in 2014-2018



As shown in Figure C-119, ammonium nitrate attributable to U.S. sources is decreasing. Emission control efforts are projected to decrease light extinction attributable to ammonium nitrate by an additional 56 percent between the current period and 2028. Ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. emission sources in 2028.

Figure C-119: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at SAGO1 on the Most Impaired Days



Regional source apportionment projections are shown in Figures C-120 and C-121. Light extinction attributable to regional sources of ammonium nitrate is about markedly larger than light extinction attributable to regional sources of ammonium sulfate. California mobile sources continue to be the largest regional source of ammonium nitrate. California's strategy is focused on reducing NOx emissions from mobile sources. This strategy is expected to lead to visibility improvements in the San Gorgonio and San Jacinto Wilderness Areas.

Figure C-120: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at SAGO1

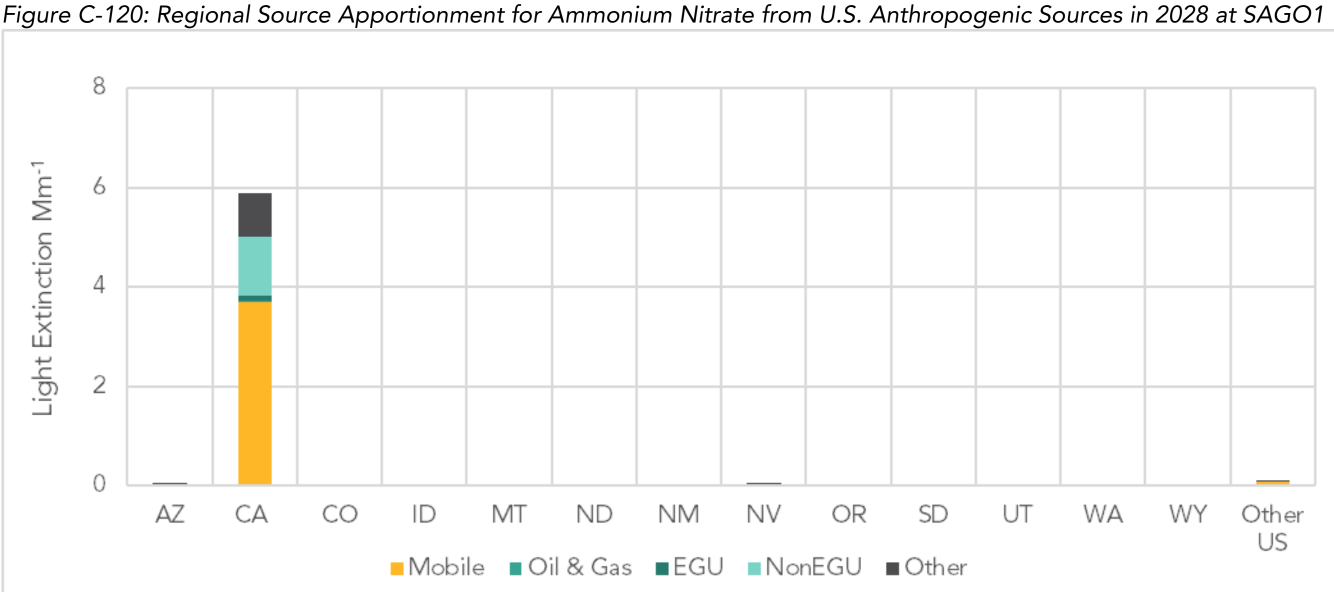
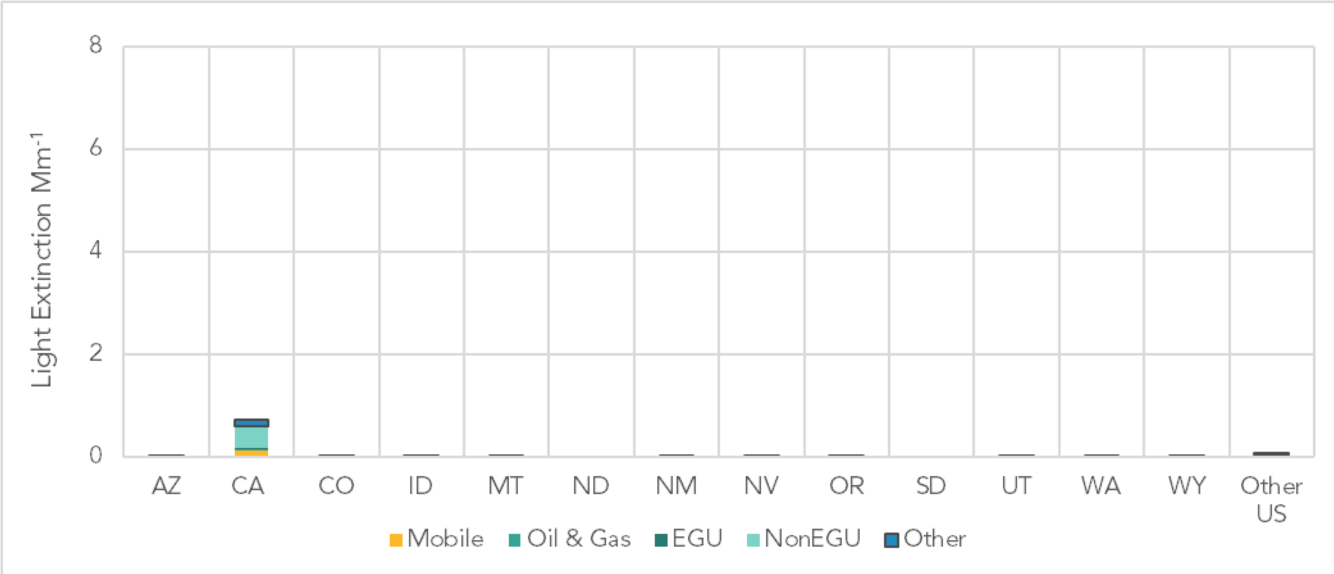
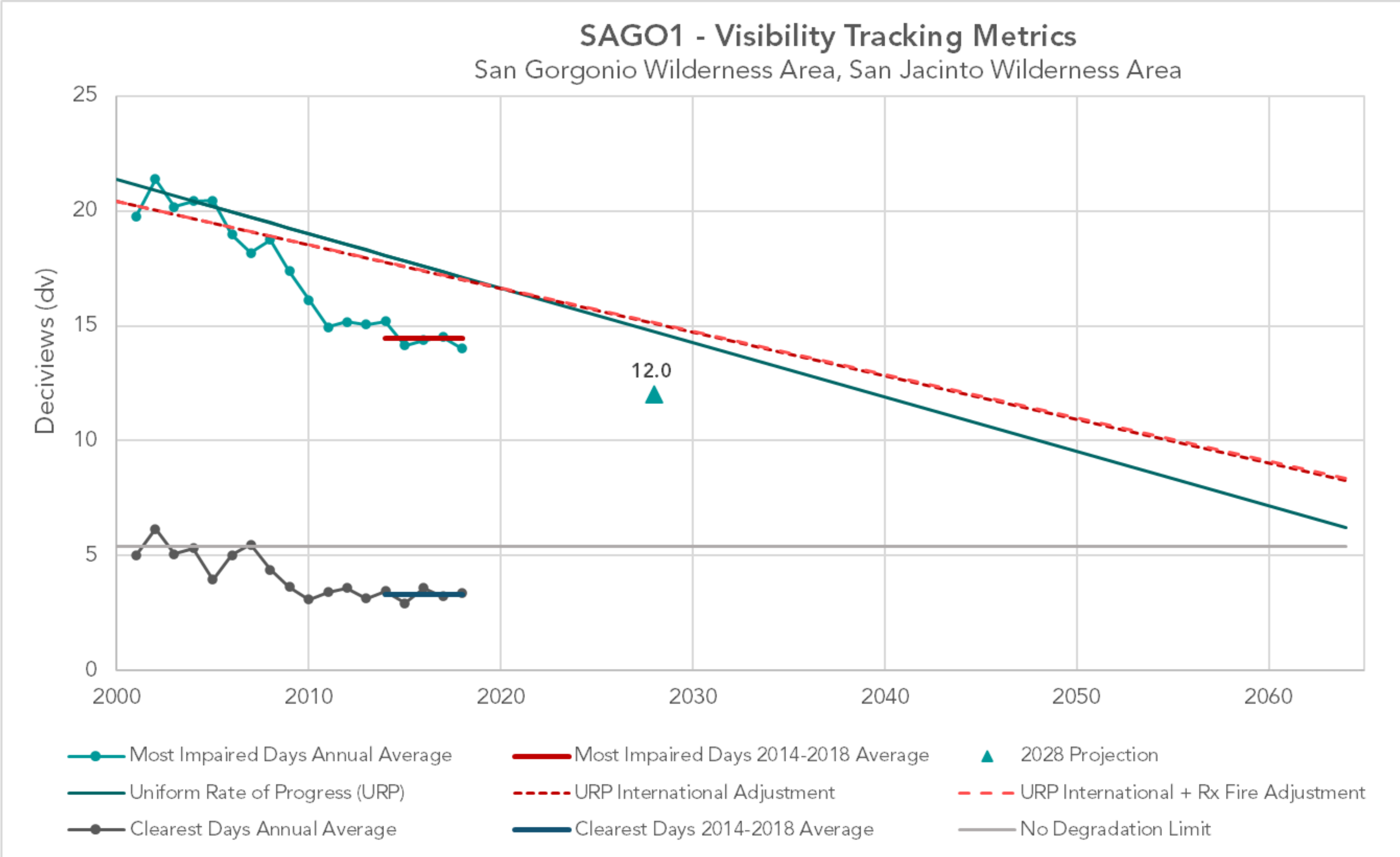


Figure C-121: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at SAGO1



The current and projected trends for visibility tracking metrics at the San Gorgonio and San Jacinto Wilderness Areas are shown in Figure C-122. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility on the most impaired days is projected to be 12.0 dv in 2028, which represents a visual range of 73 miles (117 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating that these areas are on track to meet 2064 visibility targets.

Figure C-122: Visibility Tracking Metrics and Projections for San Gorgonio Wilderness Area and San Jacinto Wilderness Area



Joshua Tree National Park (JOSH1) IMPROVE Monitoring Site

The JOSH1 monitoring site, shown below in Figure C-123, is in the western portion of Joshua Tree National Park at 4,051 feet (1,235 m) asl. The monitoring site was established in February 2000. The monitor is on the southern edge of Black Rock Campground, which has 99 developed camp sites. The town of Yucca Valley, with a population of around 20,000 people, is about 5 miles away. Data collected at the JOSH1 site are representative of visibility conditions in Joshua Tree National Park.

Figure C-123: Photograph looking northeast towards the JOSH1 IMPROVE Monitoring Site

Photograph Source: https://vista.cira.colostate.edu/Improve/monitoring-site-browser

Joshua Tree National Park spans 429,690 acres and includes vast portions of the Colorado and Mojave Deserts. The landscape is varied, ranging from dry lakebeds and sand dunes to rugged mountains. Joshua Tree National Park straddles the border of the Mojave Desert and Salton Sea Air Basins. Emissions from the adjacent urban areas contribute to visibility impairment.

As shown in Table C-16, visibility impairment on the clearest days during the baseline period was 6.1 dv. Visibility impairment on the clearest days decreased by 1.4 dv between the baseline and the current periods. During the current period, visibility impairment was 4.7 dv, which is comparable to a visual range of 151 miles (244 km).

Visibility impairment on the most impaired days during the baseline period was 17.7 dv. On the most impaired days, impairment decreased by 4.8 dv between the baseline and the current periods. During the current period, visibility impairment was 12.9 dv, which is comparable to a visual range of 67 miles (107 km). The average rate of progress between the baseline period and the current period was 0.34 dv per year. This rate is faster than the URP and more than double the adjusted URP.

Table C-16: Visibility Tracking Metrics for JOSH1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	6.1	4.7	1.7	1.4 dv	3.0 dv	--	--
Most Impaired	17.7	12.9	6.1	4.8 dv	6.8 dv	0.19 dv/year (0.15 dv/year)	0.34 dv/year

Monitoring data, shown in Figures C-124 and C-125, indicate that ammonium sulfate accounts for the largest portion of light extinction on the clearest days. Between the baseline monitoring period and the current period, light extinction from ammonium sulfate decreased by 37 percent on the clearest days. On the most impaired days, ammonium nitrate coupled with ammonium sulfate accounts for the most light extinction. Between the baseline monitoring period and the current period, light extinction from ammonium nitrate decreased by 78 percent and light extinction from ammonium sulfate decreased by 10 percent on the most impaired days.

Figure C-124: Average Extinction Composition for JOSH1 on the Clearest Days

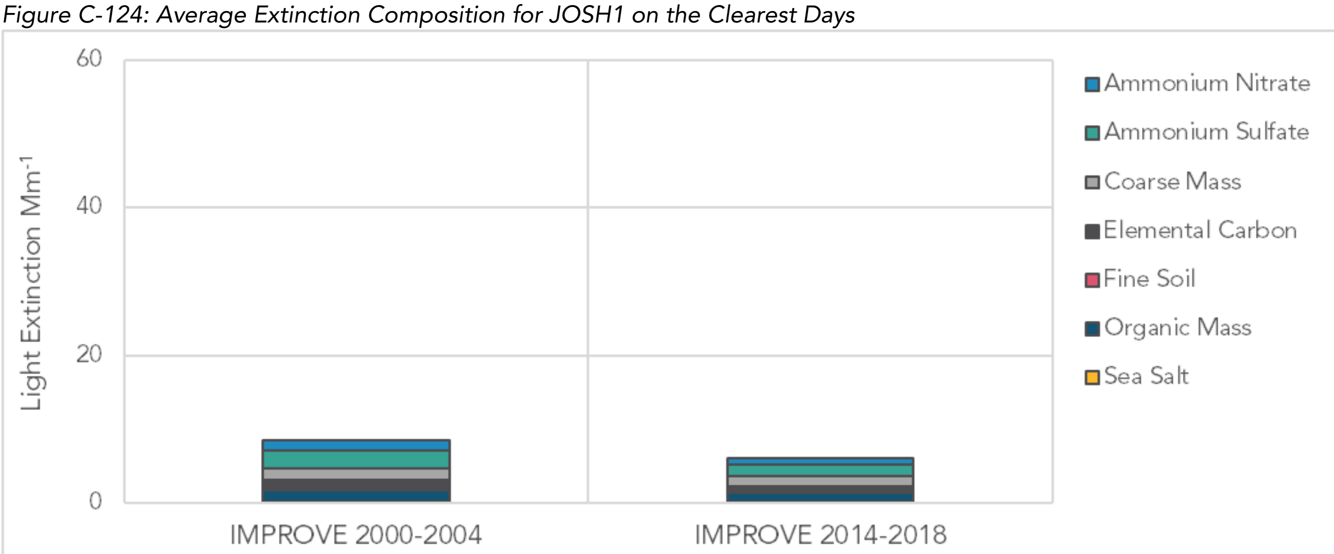
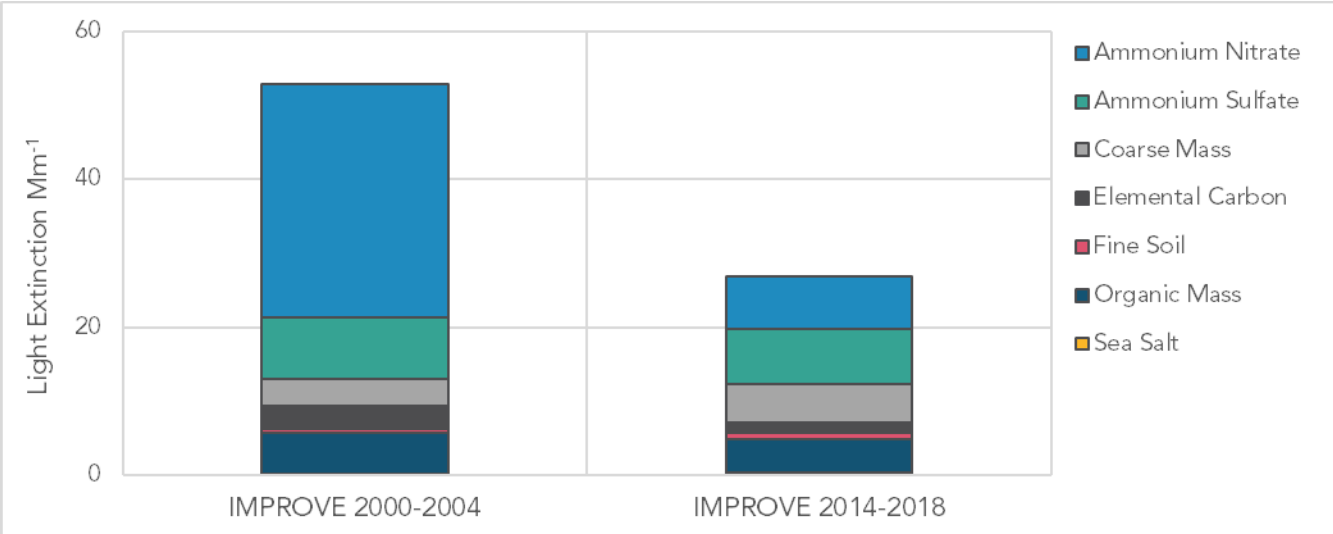
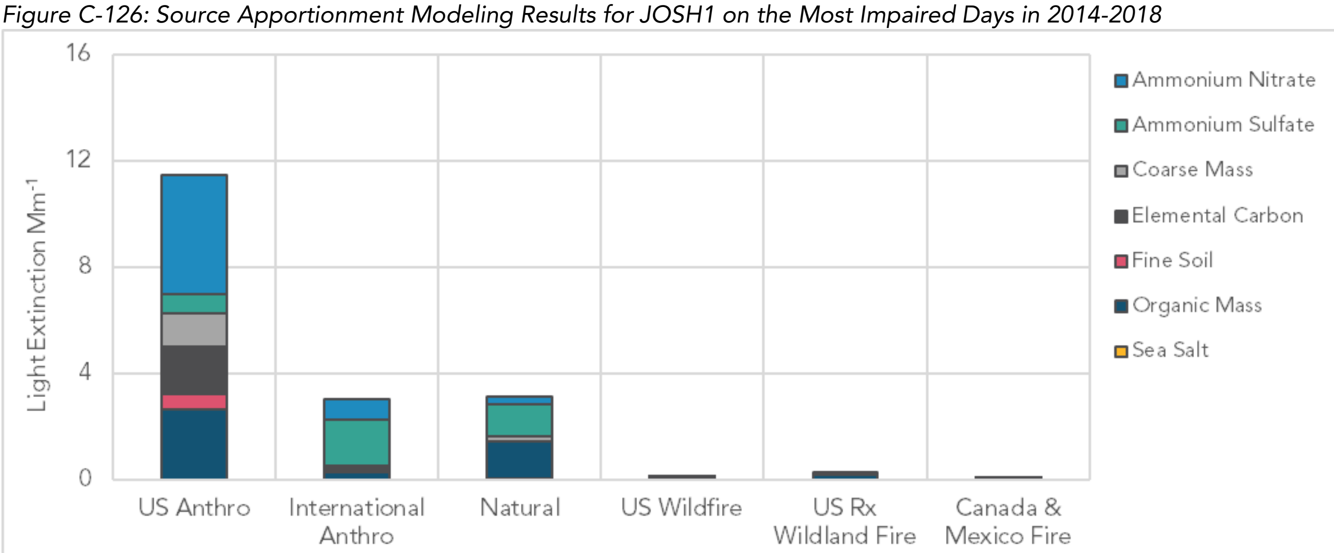


Figure C-125: Average Extinction Composition for JOSH1 on the Most Impaired Days



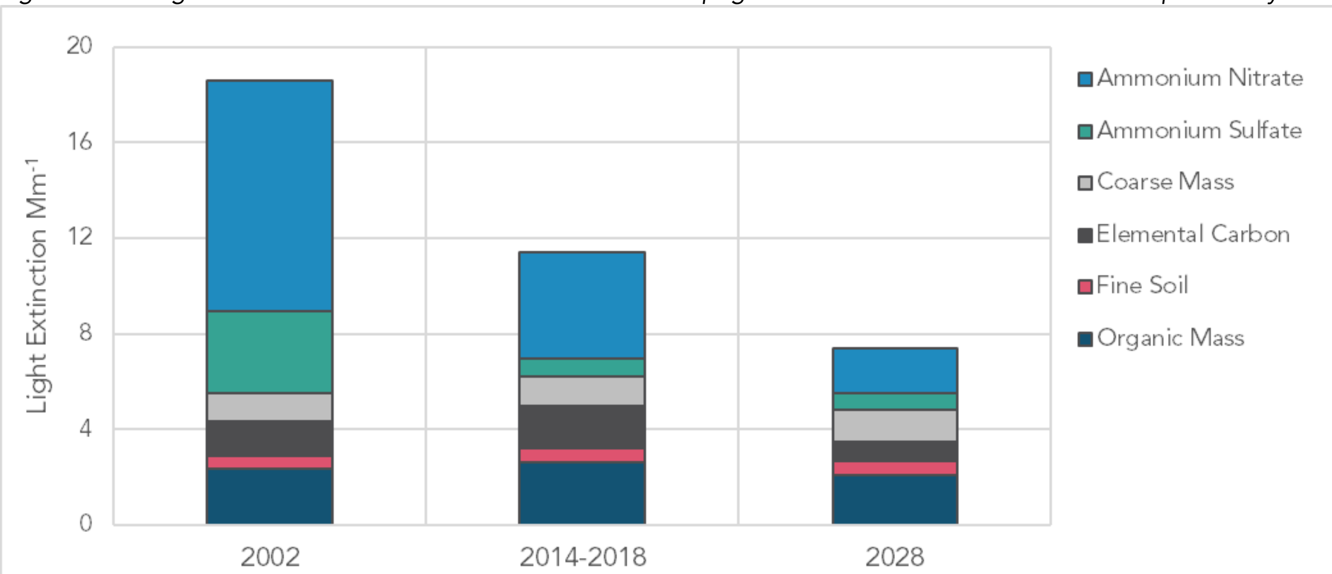
Source apportionment modeling, shown in Figure C-126, indicates that U.S. emissions make the largest contribution to light extinction measured at the JOSH1 monitoring site on the most impaired days. Emissions from natural and international sources also contribute to visibility impairment. Ammonium nitrate accounts for the largest share of light extinction attributable to U.S. sources. Ammonium sulfate accounts for the largest share of light extiction attributable to international sources and organic mass, closely followed by ammonium sulfate, accounts for the largest share of light extinction attributable to natural sources.

Figure C-126: Source Apportionment Modeling Results for JOSH1 on the Most Impaired Days in 2014-2018



Similar to other areas in this region and the rest of California, ammonium nitrate attributable to U.S. sources has been decreasing. As shown in Figure C-127, between the current period and 2028, light extinction attributable to U.S. sources is projected to decrease by an additional 60 percent. In 2028, organic mass is projected to account for the largest share of light extinction on the most impaired days, suggesting that low level source apportionment for this PM species may be needed in the next planning period.

Figure C-127: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at JOSH1 on the Most Impaired Days



Regional source apportionment projections are shown in Figures C-128 and C-129. Light extinction attributable to regional sources of ammonium nitrate is about three times larger than light extinction attributable to regional sources of ammonium sulfate. California mobile sources continue to represent the largest regional source of ammonium nitrate in 2028.

Figure C-128: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at JOSH1

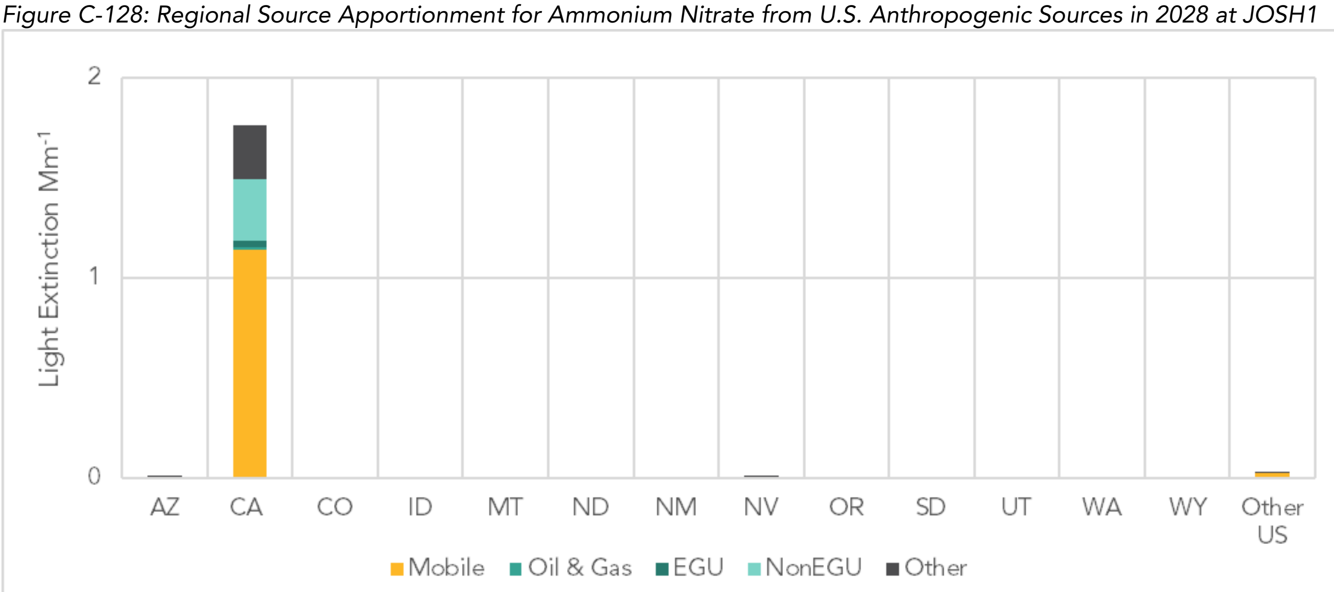
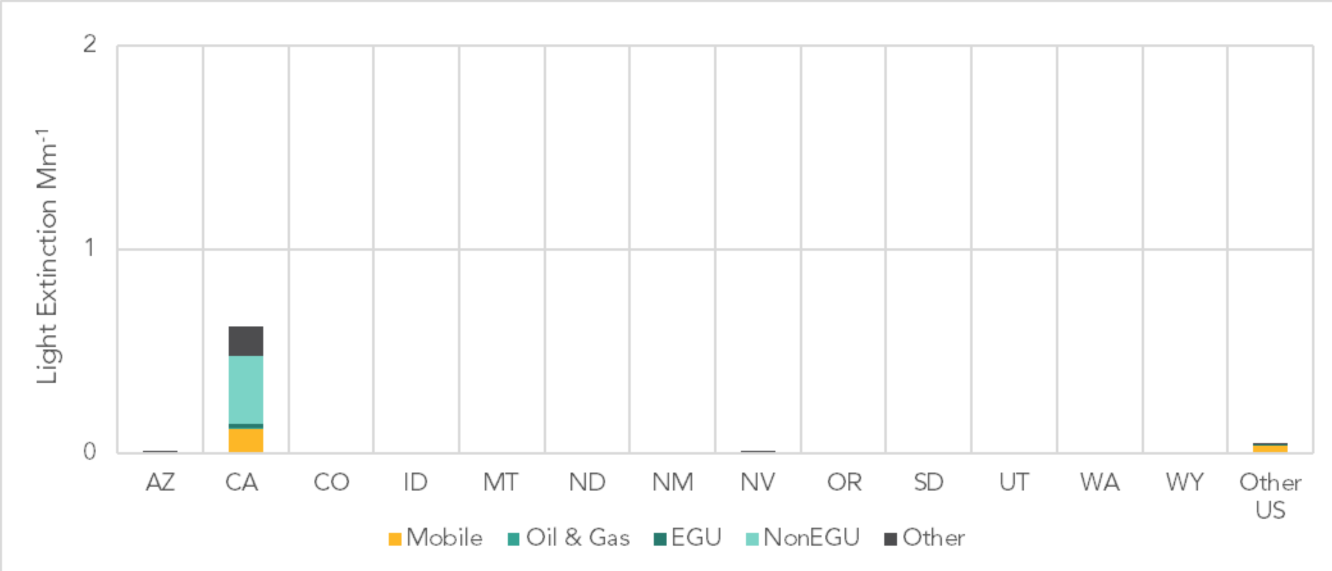
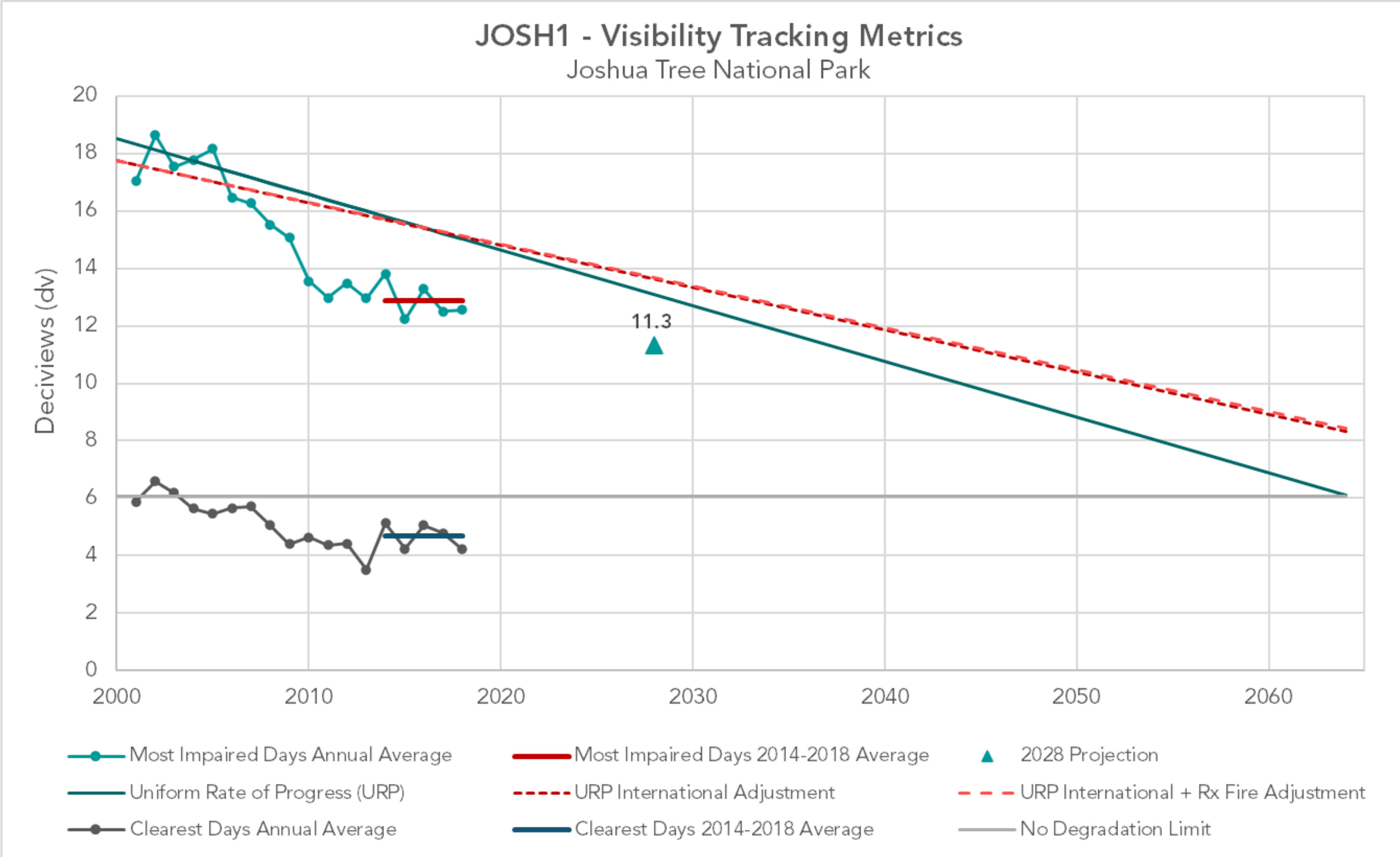


Figure C-129: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at JOSH1



The current and projected trends for visibility tracking metrics at Joshua Tree National Park are shown in Figure C-130. Accounting for adopted emission controls and the emission reduction commitment made in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 11.3 dv in 2028, which represents a visual range of 78 miles (126 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating this area is on track to meet 2064 visibility targets.

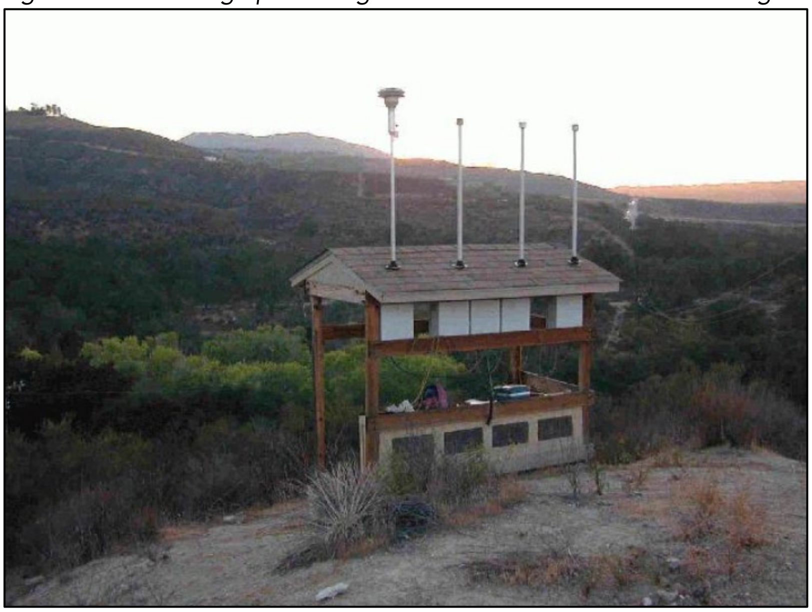
Figure C-130: Visibility Tracking Metrics and Projections for Joshua Tree National Park



Agua Tibia Wilderness Area (AGTI1) IMPROVE Monitoring Site

The AGTI1 monitoring site, shown in Figure C-131, is in the northern portion of the Agua Tibia Wilderness Area at 1663 feet (507 m) asl. The monitoring site was established in December 2000, south of California State Highway 79. Dripping Springs Campground is just south of the monitoring site and has 34 developed camp sites that are lightly used. Vail Lake, a municipal water storage reservoir and recreation destination is north of the site. The Temecula Valley wine grape growing area is northwest of Vail Lake. Interstate 15, the major connector between San Bernardino, Riverside, and San Diego Counties is about ten miles west of the site. Data collected at the AGTI1 site are representative of visibility conditions in the Agua Tibia Wilderness Area.

Figure C-131: Photograph looking southwest toward AGTI1 Monitoring Site



Photograph Source: https://vista.cira.colostate.edu/Improve/monitoring-site-browser

The Agua Tibia Wilderness Area is 15,934 acres in size with steep, densely forested terrain. Elevation ranges from 1,615 to 4,763 feet (492 to 1452 m) asl. The Agua Tibia Wilderness Area straddles the border between the South Coast and San Diego County Air Basins. Emissions from adjacent urban areas contribute to visibility impairment.

As shown in Table C-17, visibility impairment on the clearest days during the baseline period was 9.6 dv. Visibility impairment on the clearest days decreased by 2.6 dv between the baseline and the current periods. During the current period, visibility impairment was 7.0 dv, which is equivalent to a visual range of 120 miles (194 km).

Visibility impairment on the most impaired days during the baseline period was 21.6 dv. Between the baseline period and the current period, visibility impairment on the most impaired days decreased by 5.3 dv. During the current period, visibility impairment was

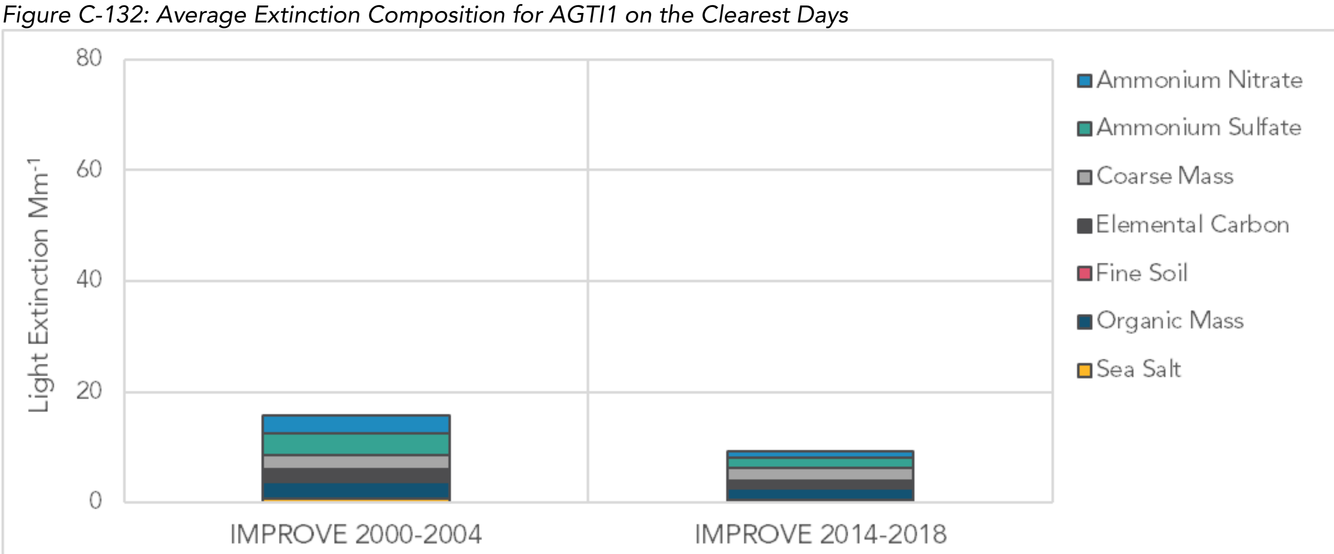
16.3 dv, which is equivalent to a visual range of 47 miles (76 km). The average rate of progress between the baseline and current periods was 0.38 dv per year. This rate is greater than the URP and more than double the adjusted URP.

Table C-17: Visibility Tracking Metrics for AGTI1

Days	Baseline (dv)	Current (dv)	Natural (dv)	Difference: Baseline - Current	Difference: Current - Natural	Uniform Rate of Progress (Adjusted)	Current Rate of Progress
Clearest	9.6	7.0	2.9	2.6 dv	4.1 dv	--	--
Most Impaired	21.6	16.3	7.7	5.3 dv	8.6 dv	0.23 dv/year (0.18 dv/year)	0.38 dv/year

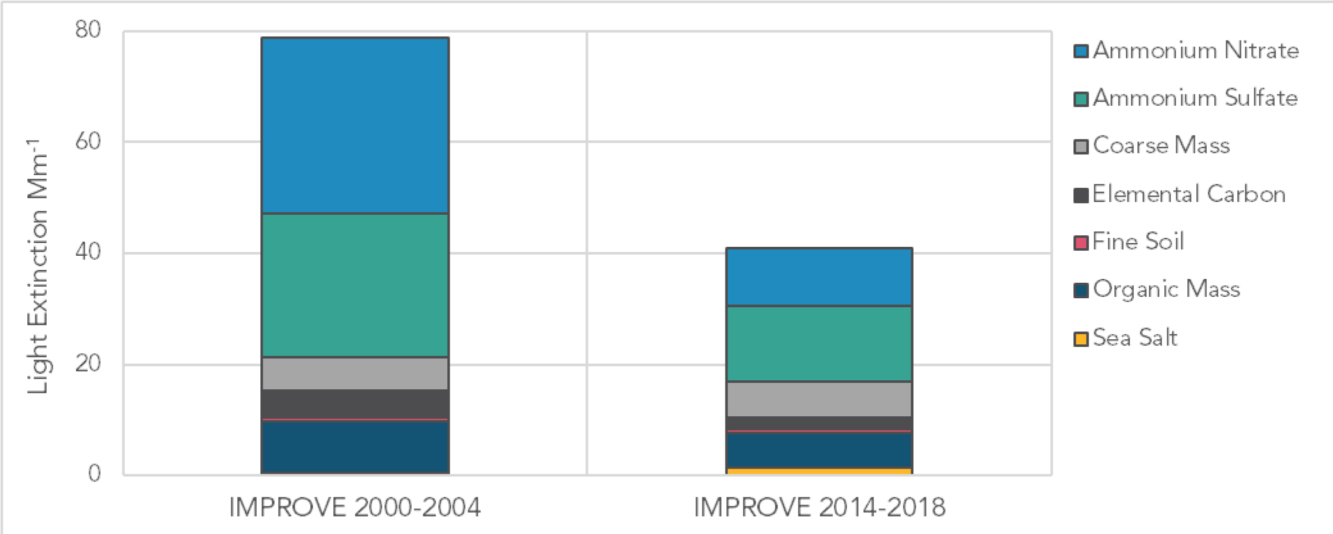
Monitoring data, shown in Figures C-132 and C-133, indicate that ammonium nitrate and ammonium sulfate had the largest contribution to light extinction on the clearest days during the baseline period. Between the baseline and current periods, light extinction from ammonium nitrate decreased by 64 percent and light extinction from ammonium sulfate decreased by 51 percent. During the current period, ammonium sulfate and coarse mass had the most dominant impact on light extinction on the clearest days.

Figure C-132: Average Extinction Composition for AGTI1 on the Clearest Days



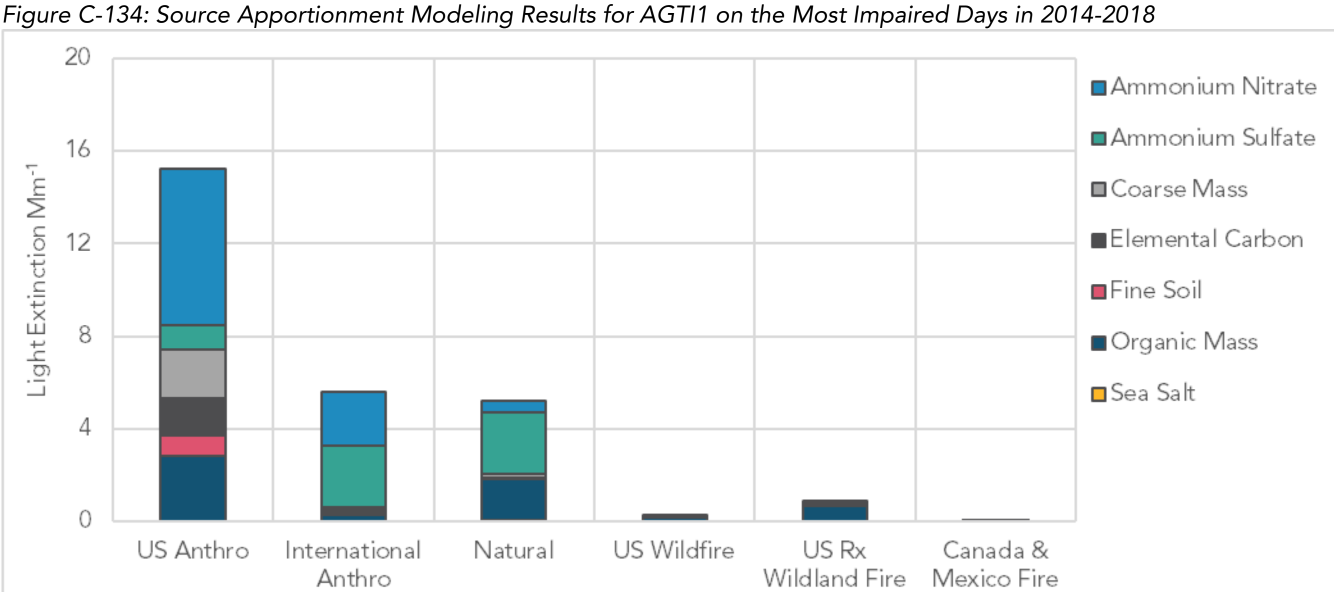
On the most impaired days, ammonium nitrate and ammonium sulfate accounted for the largest portion of the light extinction during the baseline and current periods. Between the baseline and current periods, light extinction from ammonium nitrate decreased by 67 percent and light extinction due to ammonium sulfate decreased by 48 percent.

Figure C-133: Average Extinction Composition for AGTI1 on the Most Impaired Days



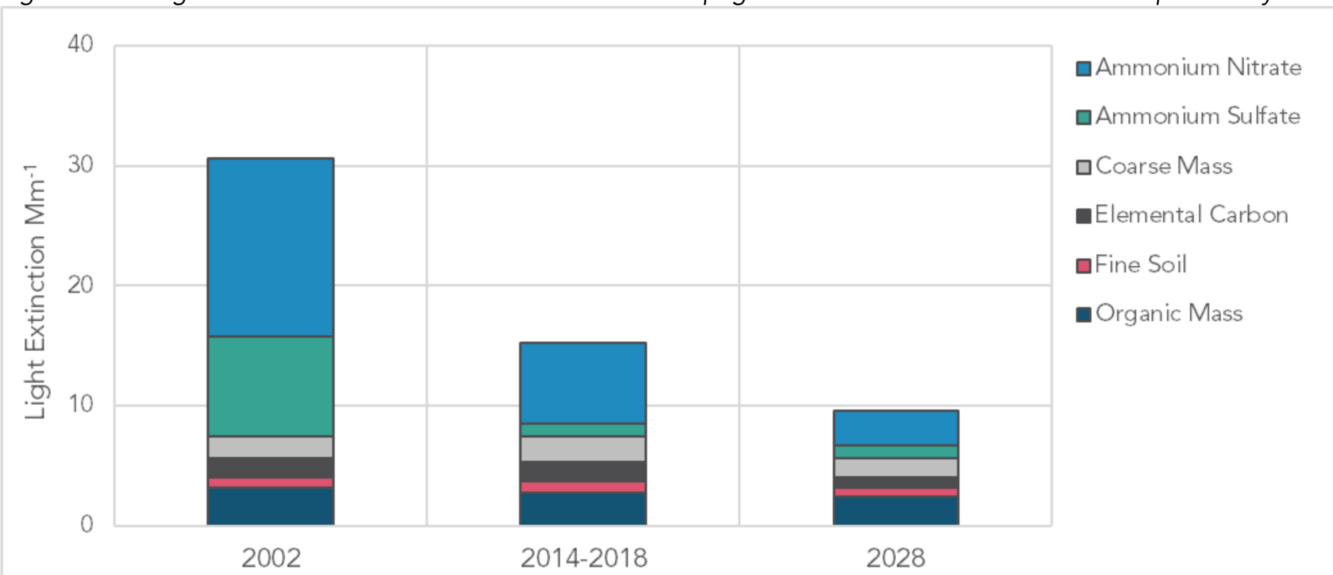
Source apportionment modeling, shown in Figure C-134, indicates that emissions from U.S. sources account for the largest portion of light extinction on most impaired days. Emissions from international sources, natural sources, and fire also contribute to impaired visibility. Ammonium nitrate accounts for the largest portion of light extinction from the U.S. sources. Ammonium sulfate, closely followed by ammonium nitrate, accounts for the largest portion of light extinction from international sources. Ammonium sulfate accounts for the majority of light extinction from natural sources.

Figure C-134: Source Apportionment Modeling Results for AGTI1 on the Most Impaired Days in 2014-2018



As shown in Figure C-135, light extinction attributable to U.S. sources is decreasing. Ammonium nitrate has accounted for the largest share of light extinction attributable to this source group. Between the current period and 2028, light extinction from ammonium nitrate is projected to decrease by 57 percent. Ammonium nitrate is projected to continue to account for the largest share of light extinction attributable to U.S. emission sources in 2028, but will be closely followed by light extinction attributable to organic mass.

Figure C-135: Light Extinction from PM Attributed to U.S. Anthropogenic Sources at AGTI1 on the Most Impaired Days



Regional source apportionment projections are shown in Figures C-136 and C-137. Light extinction attributable regional sources of ammonium nitrate is about three times greater than light extinction attributable to ammonium sulfate from regional sources. California mobile sources are the largest regional source of ammonium nitrate.

Figure C-136: Regional Source Apportionment for Ammonium Nitrate from U.S. Anthropogenic Sources in 2028 at AGTI1

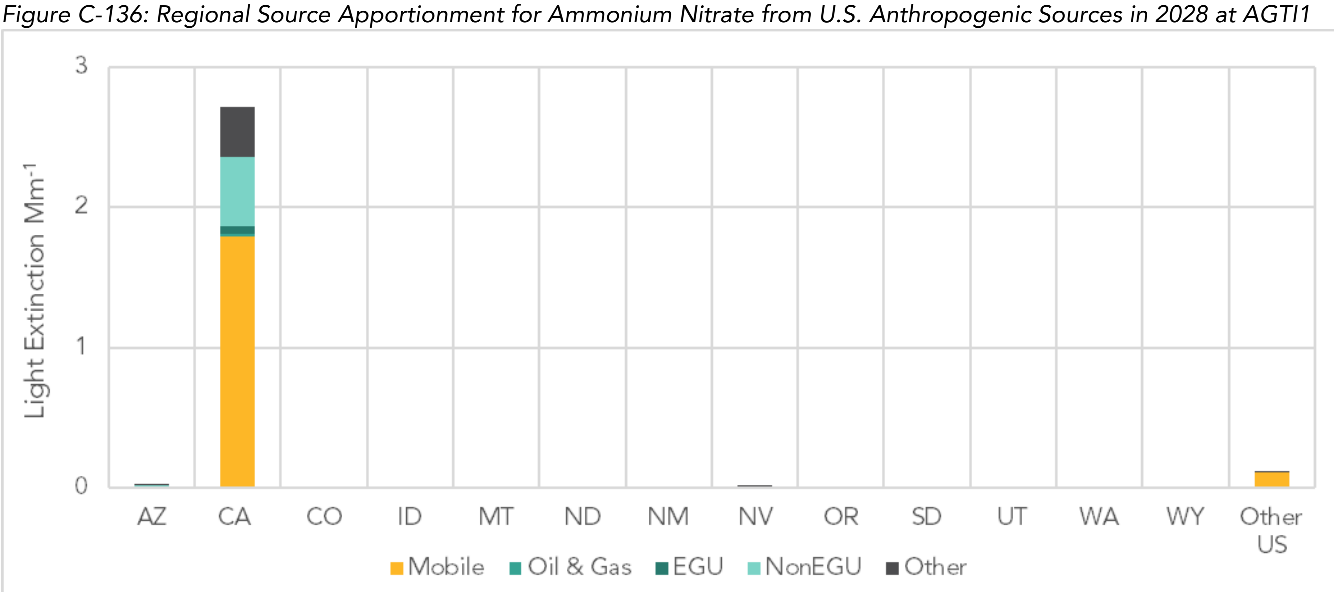
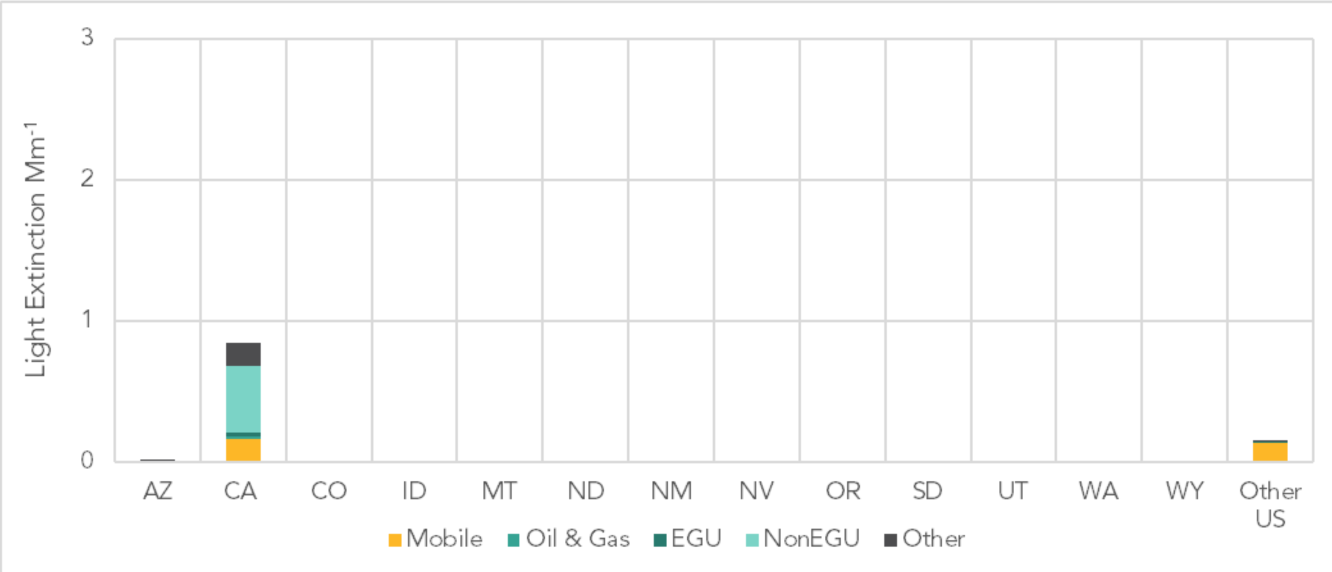


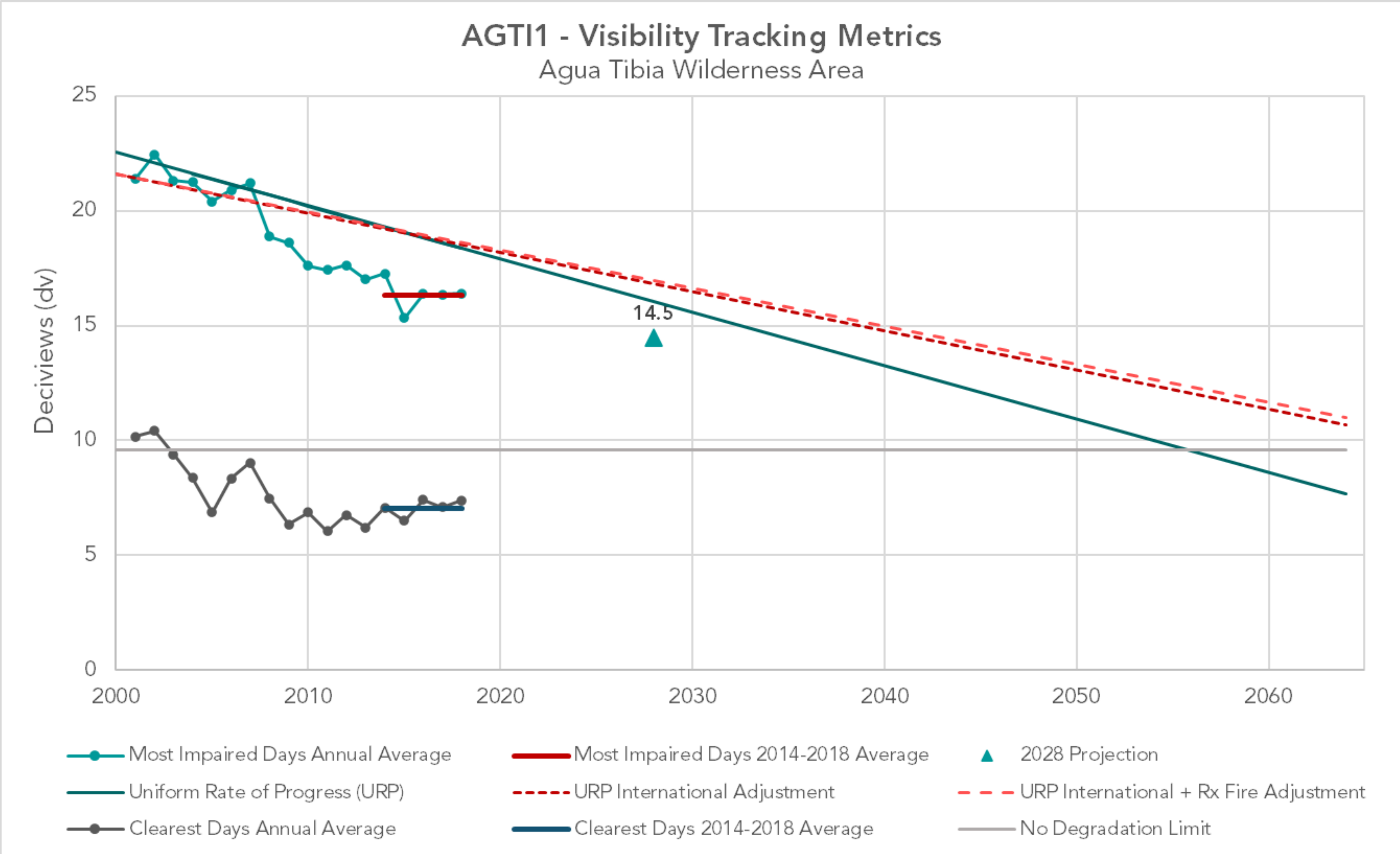
Figure C-137: Regional Source Apportionment for Ammonium Sulfate from U.S. Anthropogenic Sources in 2028 at AGTI1



California's long-term strategy for regional haze is focused on improving visibility through reduction of NOx emissions from mobiles sources. This strategy is projected to improve visibility conditions in the Agua Tibia Wilderness Area.

The current and projected visibility tracking metrics for the Agua Tibia Wilderness Area are shown in Figure C-138. Accounting for adopted emission controls and emission reduction commitments included in this Regional Haze Plan, visibility impairment on the most impaired days is projected to be 14.5 dv in 2028, which is comparable to a visual range of 57 miles (91 km). This 2028 projection is below the adjusted glidepath that accounts for international and wildland prescribed fire emissions, indicating that this area is on track to meet 2064 visibility targets.

Figure C-138: Visibility Tracking Metrics and Projections for Agua Tibia Wilderness Area



D. Description of Emission Inventory Components

Mobile Sources

CARB develops the emission inventory for the mobile sources using various modeling methods. These modeling methods account for the effects of various adopted regulations, technology types, fleet turnover, and seasonal conditions on emissions. Mobile sources in the emission inventory are composed of both on-road and off-road sources described in the sections below.

On-Road Mobile Sources

Emissions from on-road mobile sources were estimated using outputs from CARB's EMFAC2017 model. The on-road emissions were calculated by applying EMFAC2017 emission factors to the transportation activity data provided by the local metropolitan planning organizations.

EMFAC2017 includes data on California's car and truck fleets and travel activity. It utilizes a socio-econometric regression modeling approach to forecast new vehicle sales and to estimate future fleet mix. Light-duty motor vehicle fleet age, vehicle type, and vehicle population were updated based on 2016 Department of Motor Vehicles (DMV) registration data. Updates to mileage accrual were based on Smog Check data. Updates to heavy-duty trucks include model year specific emission factors based on new test data, and population estimates using DMV data for in-state trucks and International Registration Plan (IRP) data for out-of-state trucks. The EMFAC2017 model also reflects the emissions benefits from implementation of CARB's recent rulemakings and previously adopted rules for on-road sources.

Additional information on the EMFAC2017 model is available online.[11]

Off-Road Mobile Sources

Emissions from off-road sources were estimated using a suite of category-specific models or the OFFROAD2007 model for categories when a new model was not available. Many of the newer models were developed to support recent regulations. The categories of off-road sources that have been recently updated include ocean-going vessels, commercial harbor craft, pleasure craft and recreational vehicles, locomotives, fuel storage and handling, agricultural diesel equipment, in-use off-road equipment, cargo handling equipment, and transportation refrigerated units. The following sections summarize the updates for each

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[11] *https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/msei-road-documentation*

category and provide weblinks to where additional information about the methodology for each category can be viewed.

Additional information on the OFFROAD2007 model is available online.[12]

Ocean-Going Vessels

CARB staff updated the ocean-going vessels (OGV) activity growth rates and NOx emission calculations in December 2016. These OGV updates were based on 2014 data on vessel visits, 2014 data from the Ports of Los Angeles and Long Beach on vessel power, and U.S. EPA sources for emission rates. Growth factors were based on the Freight Analysis Framework.

Additional information on CARB's general OGV methodology including the 2014 update[13] and the 2019 update[14] is available online.

Commercial Harbor Craft

Commercial Harbor Craft (CHC) are grouped into nine vessel types that include ferry and excursion vessels, tow boats, tugboats, pilot vessels, work boats, crew and supply vessels, commercial fishing vessels, charter fishing vessels, and other. Vessel and engine data were reported to CARB by vessel operators in compliance with CARB's 2007 Commercial Harbor Craft Regulation. Staff updated the crew and supply vessel emissions inventory using 2009 reporting data and developed barge and dredge vessel emissions inventories using information from a 2009 CARB survey. Vessel population data were collected from various sources, including the U.S. Coast Guard, the California Department of Fish and Wildlife registration data, the CARB Harbor Craft Survey, and information from recent emission inventory estimates generated for Los Angeles. Vessel and engine profiles, including vessel and engine type, age, size, annual hours of operation, and annual fuel use were developed based on the CARB survey.

Additional information on CARB's CHC methodology is available online.[15]

Pleasure Craft and Off-Highway Recreational Vehicles

Pleasure craft is a broad category of marine vessels that includes gasoline powered spark-ignition marine watercraft and diesel-powered marine watercraft. Off-highway recreational vehicles (OHRV) include off-highway motorcycles, all-terrain vehicles, off-road sport vehicles,

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[12] *https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/msei-road-documentation-0*
[13] https://ww3.arb.ca.gov/msei/2014-updates-to-the-carb-ogv-model.docx
[14] *https://ww3.arb.ca.gov/msei/offroad/pubs/2019_ogv_inventory_writeup_ver_oct_18_2019.pdf*
[15] *https://www.arb.ca.gov/regact/2010/chc10/appc.pdf*

off-road utility vehicles, sand cars, and golf carts. A new model was developed in 2014 to estimate emissions from pleasure craft and another new model was developed in 2018 to estimate emissions from recreational vehicles. Population, activity, and emission factors were reassessed in the new models using data from new surveys, DMV registration information, and emissions testing.

Additional information on CARB's Pleasure Craft and OHRV methodology is available online.[16]

Locomotives

The locomotive model is based primarily on population and activity data reported to CARB by the major rail lines for calendar year 2011. To estimate emissions, CARB used duty cycle, fuel consumption, and activity data from the two main rail companies. Activity is forecasted for individual train types and is consistent with CARB's ocean-going vessel and truck growth rates. Fuel efficiency improvements are projected to follow Federal Railroad Association. Projections and turnover assumptions are consistent with U.S. EPA projections. The model was updated in 2016 with revised growth rates, and revised turnover assumptions.

Additional information on CARB's Locomotive methodology is available online.[17,18]

Fuel Storage and Handling

Emissions for fuel storage and handling were estimated using the OFFROAD2007 model.

Additional information is available online.[19]

Agricultural Diesel Equipment

The inventory for agricultural diesel equipment (such as tractors, harvesters, combines, sprayers, and others) was revised based on a voluntary survey of farmers, custom operators, and first processors conducted in 2009. The survey data, along with information from the 2007 U.S. Department of Agriculture's (USDA) Farm Census, was used to revise population, activity, age distribution, fuel use, and allocation. This updated inventory replaces general information on farm equipment in the United States with one specific to California farms and

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[16] *https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-offroad*

[17] *https://ww3.arb.ca.gov/msei/ordiesel/locolinehaul2017ei.docx*

[18] *https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-offroad-0*

[19] *https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-offroad*

practices. Additionally, through a contract with URS Corporation, agricultural growth rates through 2050 were updated.

Additional information on CARB's Agricultural Diesel Equipment methodology is available online.[20]

In-Use Off-Road Equipment

The In-Use Off-Road Equipment category includes construction, industrial, mining, oil drilling, and ground support equipment. CARB developed this model in 2010 to support the analysis for amendments to the In-Use Off-Road Diesel Fueled Fleets Regulation. Population used in the model is based on reporting data, while activity, load, and fuel use are based on survey data and statewide fuel estimates.

Additional information on CARB's In-Use Off-Road Methodology is available online.[21]

Cargo Handling Equipment

The emissions inventory for the Cargo Handling Equipment category was updated to reflect new information on equipment population, activity, recessionary impacts on growth, and engine load in 2011. The information includes regulatory reporting data which provide an accounting of all the cargo handling equipment in the State including their model year, horsepower, and activity.

Additional information on CARB's Cargo Handling Equipment Methodology is available online.[22]

Transport Refrigeration Units

The Transport Refrigeration Unit (TRU) model reflects updates to activity, population, growth and turn-over data, and emission factors developed to support the 2011 amendments to the Airborne Toxic Control Measure for In-Use Diesel-Fueled Transport Refrigeration Units.

Additional information on CARB's TRU Methodology is available online.[23]

Stationary Sources

The stationary source emission inventory is composed of point sources and stationary area sources. The data elements in the 2014 base year inventory are consistent with the data elements required by the Air Emissions Reporting Requirements (AERR). The inventory

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[20] *https://ww3.arb.ca.gov/msei/ordiesel/ag2011invreport.pdf*

[21] *https://ww3.arb.ca.gov/regact/2010/offroadlsi10/offroadappd.pdf*

[22] *http://ww2.arb.ca.gov/sites/default/files/barcu/regact/2011/cargo11/cargoappb.pdf*

[23] *https://ww3.arb.ca.gov/msei/2011-documentation-appendix-c-references.zip*

reflects actual emissions from industrial point sources reported to the local districts by the facility operators through calendar year 2014.

Stationary area sources also include smaller point sources, such as gasoline dispensing facilities and laundering, that are not inventoried individually, but are estimated as a group and reported as a single source category. Emissions from these sources are estimated using various models and methodologies. Estimation methods include source testing, direct measurement by continuous emissions monitoring systems, or engineering calculations. Emissions for these categories are estimated by both CARB and the local air districts. Estimates for the categories below were developed by CARB and have been reviewed by CARB staff to reflect the most up-to-date information.

The estimates for some source categories were developed several years prior to the current base year. In those cases, CARB staff grew the original estimates according to growth and control factors. The growth factors CARB relied upon are described below, except for any district-specific control profiles such as those provided by the Bay Area Air Quality Management District (AQMD) and Southern California Association of Governments' districts (Antelope Valley AQMD, Mojave Desert AQMD, Ventura County Air Pollution Control District (APCD), Imperial County APCD, and South Coast AQMD).

Stationary Nonagricultural Diesel Engines

The stationary nonagricultural diesel engine category includes emissions from backup and prime generators and pumps, air compressors, and other miscellaneous stationary diesel engines that are widely used throughout the industrial, service, institutional, and commercial sectors. The emission estimates, including emission forecasts, are based on a 2003 CARB methodology derived from the OFFROAD model.

Additional information on CARB's stationary nonagricultural diesel engine methodology is available online.[24]

Agricultural Diesel Irrigation Pumps

The agricultural diesel irrigation pumps category includes emissions from the operation of diesel-fueled stationary and mobile agricultural irrigation pumps. The emission estimates are based on a 2003 CARB methodology using statewide population and include replacements due to the Carl Moyer Program. Emissions are grown based on projected acreage for irrigated farmland from the California Department of Conservation's Farmland Mapping and Monitoring Program (FMMP), 2008.

[24] *https://ww3.arb.ca.gov/ei/areasrc/arbfuelcombother.htm*

Additional information on CARB's agricultural diesel irrigation pumps methodology is available online.[25]

Wine Fermentation and Aging

The wine fermentation and aging category includes emissions from the fermentation and aging of wine. Wine fermentation volumes in California are reported by the U.S. Alcohol and Tobacco Tax and Trade Bureau. CARB staff derived the emission factors from a computer model developed by Williams and Boulton. Emissions were initially estimated for 2002 and grown to later years using beverage manufacturing (alcoholic & non-alcoholic) economic output. An emission factor for brandy was derived by Hugh Cook of the Wine Institute. Emissions for brandy were initially estimated for 1992 then grown to 2012 using economic output for food manufacturing. Emissions were grown from 2012 to 2014 using beverage manufacturing economic output per Regional Economic Models, Inc. (REMI). Growth for future years is based on REMI version 2.2.2 forecasts.

Additional information on CARB's wine fermentation and aging methodology is available online.[26]

Waste Disposal and Composting Facilities

The waste disposal and composting facilities category includes emissions from composting facilities that process organic materials via open windrow composting or aerated static pile processes. The emission estimates are based on 2015 CARB methodology using facility specific emissions testing or an emission factor derived from testing at composting facilities. Growth is based on California Department of Finance (DOF) population forecasts from 2017.

Additional information on CARB's waste disposal and composting methodology is available online.[27]

Laundering

The laundering category includes emissions from perchloroethylene (perc) dry cleaning establishments. The emission estimates are based on a 2002 CARB methodology that used nationwide perc consumption rates allocated to the county level based on population and an emission factor of 10.125 pounds per gallon used. Emissions were grown from the original estimates to 2012 using DOF population growth trends. Future-year growth is based on DOF population forecasts for 2017.

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[25] *https://ww3.arb.ca.gov/ei/areasrc/fullpdf/full1-1.pdf*

[26] *https://ww2.arb.ca.gov/carb-industrial-process-methodologies-food-and-agriculture*

[27] *https://ww3.arb.ca.gov/ei/areasrc/composting_emissions_inventory_methodology_final_combined.pdf*

Additional information on CARB's laundering methodology is available online.[28]

Degreasing

The degreasing category includes emissions from solvents in degreasing operations in the manufacturing and maintenance industries. The emissions estimates are based on a 2000 CARB methodology using survey and industry data, activity factors, emission factors and a user's fraction. Emissions were grown based on CARB/REMI industry-specific economic output, version 2.2.2.

Additional information on CARB's degreasing methodology is available online.[29]

Coatings and Thinners

The coatings and thinners category includes emissions from coatings and related process solvents. Auto refinishing emissions estimates are based on a CARB methodology using production data and a composite emission factor derived from a 2002 survey. These estimates were grown to 2014 based on industry-specific employment projections. Future years were grown based on CARB's on-road mobile sources model (EMFAC2014). Estimates for industrial coatings emissions are based on a 1990 CARB methodology using production and survey data, and emission factors derived from surveys. Estimates for thinning and cleaning solvents are based on a 1991 CARB methodology, census data and a default emission factor developed by CARB. These estimates were grown by REMI county economic forecasts, version 2.2.2.

Additional information on CARB's coatings and thinners methodologies is available online.[30]

Adhesives and Sealants

The adhesives and sealants category includes emissions from solvent-based and water-based solvents contained in adhesives and sealants. Emissions are estimated based on a 1990 CARB methodology using production data and default emission factors. Estimates were grown based on REMI economic forecasts, version 2.2.2.

Additional information on CARB's adhesives and sealants methodology is available online.[31]

Gasoline Dispensing Facilities

The gasoline dispensing facilities category uses a 2015 CARB methodology to estimate emissions from fuel transfer and storage operations at gasoline dispensing facilities (GDF).

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[28] *https://ww3.arb.ca.gov/ei/areasrc/arbcleanlaund.htm*

[29] *https://ww3.arb.ca.gov/ei/areasrc/arbcleandegreas.htm*

[30] *https://ww3.arb.ca.gov/ei/areasrc/arbcleancoatreproc.htm*

[31] *https://ww2.arb.ca.gov/carb-cleaning-and-surface-coating-methodologies-adhesives-and-sealants*

The methodology addresses emissions from underground storage tanks, vapor displacement during vehicle refueling, customer spillage, and hose permeation. The updated methodology uses emission factors developed by CARB staff that reflect more current in-use test data and accounts for the emission reduction benefits of onboard refueling vapor recovery (ORVR) systems. The emission estimates are based on 2012 statewide gasoline sales data from the California Board of Equalization that were apportioned to the county level using fuel consumption estimates from EMFAC2014. Emissions were grown based on EMFAC2014.

Additional information on CARB's gasoline dispensing facilities methodology is available online.[32]

Gasoline Cargo Tanks

The gasoline cargo tank category uses a 2002 CARB methodology to estimate emissions from gasoline cargo tanks. These emissions do not include the emissions from loading and unloading of gasoline cargo tank product; they are included in the gasoline terminal inventory and gasoline service station inventory. Pressure-related fugitive emissions are volatile organic vapors leaking from three points: fittings, valves, and other connecting points in the vapor collection system on a cargo tank. 1997 total gasoline sales were obtained from the California Department of Transportation. The emission factors are derived from the data in the report, "Emissions from Gasoline Cargo Tanks, First Edition," published by the Air and Waste Management Association in 2002. The initial emission estimates for 1997 were grown to 2012 using a growth parameter developed by Pechan based on gasoline and oil expenditures data. Emissions beyond 2012 were grown according to fuel consumption from CARB's EMFAC2014 mobile sources emission factors model.

Additional information on CARB's gasoline cargo tank methodology is available online.[33]

Marine Petroleum Loading and Unloading

The marine petroleum loading categories are used to inventory 1987 hydrocarbon emissions associated with loading crude oil, residual oil, gasoline, and jet fuel into marine tankers and gasoline into barges. Emissions result from the displacement of vapors existing in the tank before loading and those generated as new product is loaded. The amounts of crude oil, gasoline, jet fuel, and residual oil shipped off from California ports were obtained from a U.S. Army Corps of Engineers report "Waterborne Commerce of the United States, Calendar Year 1986" Part 4. The emission factor for crude oil loading into tankers was obtained from the report "Hydrocarbon Emissions During Marine Loading of Crude Oils" from Western Oil and Gas Association (1977). The gasoline emission factors for loading into tankers and barges and

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[32] *https://ww2.arb.ca.gov/arb-petroleum-production-and-marketing-methodologies-petroleum-marketing*

[33] *https://ww2.arb.ca.gov/arb-petroleum-production-and-marketing-methodologies-petroleum-marketing*

jet fuel into tankers were obtained from CARB's "Report to the Legislature on Air Pollutant Emissions from Marine Vessels" (1984). The emission factor for residual oil loading into tankers was obtained from the "Inventory of Emissions from Marine Operations within California Coastal Waters, Preliminary Draft" report by Scott Environmental Technology, Inc. (1980). No growth was assumed for these emissions.

Additional information on CARB's marine petroleum loading methodology is available online.[34]

The marine petroleum unloading categories are used to estimate hydrocarbon emissions associated with lightering crude oil and ballasting marine vessels after unloading crude oil or gasoline. The amounts of crude oil and gasoline unloaded at California ports were obtained from the U.S. Army Corps of Engineers report "Waterborne Commerce of the United States, Calendar Year 1986" Part 4. Crude oil lightering data was obtained from the Bay Area AQMD for 1987. Crude oil and gasoline ballasting data for San Luis Obispo for 1987 was obtained from the U.S. Army Corps of Engineers. The volume of water used for ballasting following a cargo discharge was obtained from CARB's "Report to the Legislature on Air Pollutant Emissions from Marine Vessels" (1984). The crude oil lightering emission factor was obtained from "Hydrocarbon Emissions During Marine Loading of Crude Oils," Western Oil and Gas Association (1977). Ballasting crude oil and gasoline vessels emission factors were obtained from "Inventory of Emissions from Marine Operations within the California Coastal waters," by Scott Environmental Technology, Inc. (1981). No growth is assumed for this category.

Additional information on CARB's marine petroleum unloading methodology is available online.[35]

Oil and Natural Gas Production

The oil and natural gas production inventory is estimated by a 2015 CARB methodology. This category is related to fugitive emissions from production-related fuel consumption, fugitive losses (sumps, pits, pumps, compressors, well heads, separators, valves, and fittings), vapor recovery and flares, tank and truck working and breathing losses, wastewater treatment, tertiary production, and wet and dry gas stripping. Emissions were calculated using U.S. EPA's Oil and Natural Gas Tool v1.4 with default emissions factors from ENVIRON International Corporation's 2012 report, "2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States," and activity data taken from California's Division of Oil, Gas, and Geothermal Resources (DOGGR). CARB also incorporated data from the 2007 Oil and Gas Industry Survey (e.g., typical component counts) and feedback from individual air

[34] *https://ww2.arb.ca.gov/arb-petroleum-production-and-marketing-methodologies-petroleum-marketing*

[35] *https://ww2.arb.ca.gov/arb-petroleum-production-and-marketing-methodologies-petroleum-marketing*

districts (e.g., minimum controls required to operate in a certain district, with associated control factors) to improve these parameters and further adjust the tool's output. Emissions were grown to 2014 based on DOGGR historical statewide production. Growth in future years assumed a 2.9 percent annual decline, which reflects the statewide DOGGR trend from 2000 through 2016.

Additional information on CARB's oil and natural gas production methodology is available online.[36, 37]

Area Sources

Area sources include categories where emissions take place over a wide geographic area, such as consumer products. Emissions from these sources are estimated using various models and methodologies. Estimation methods include source testing, direct measurement by continuous emissions monitoring systems, or engineering calculations. Emissions for these categories are estimated by both CARB and local air districts.

Estimates for the categories below were developed by CARB and have been reviewed by CARB staff to reflect the most up-to-date information. The estimates for some categories were developed several years prior to the current base year. In those cases, CARB staff grew the original estimates according to growth and control factors. The growth factors CARB relied upon are described below, except for any district-specific growth factors, such as those provided by the Bay Area AQMD and Southern California Association of Governments' districts (Antelope Valley AQMD, Mojave Desert AQMD, Ventura County APCD, Imperial County APCD, and South Coast AQMD).

Consumer Products

The consumer products and aerosol coatings category reflects surveys conducted by CARB staff for the years 2003, 2006, 2008, and 2010. Together these surveys collected updated product information and ingredient information for approximately 350 product categories. Based on the survey data, CARB staff determined the total product sales and total volatile organic compounds (VOC) emissions for the various product categories. The growth trend for most consumer product subcategories is based on DOF population forecasts. A notable exception is aerosol coatings. Staff determined that a no-growth profile would be more appropriate for this category based on survey data that show relatively flat sales of these products over the last decade.

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36 *https://ww2.arb.ca.gov/resources/documents/oil-and-gas-industry-survey*

37 *https://ww3.arb.ca.gov/ei/areasrc/oilandgaseifinalreport.pdf*

Additional information on CARB's consumer products surveys is available online.[38]

Architectural Coatings

The architectural coatings category reflects emission estimates based on a comprehensive CARB survey for the 2004 calendar year. The emission estimates include benefits of the 2007 CARB Suggested Control Measures. These emissions are grown based on DOF population forecasts, 2017.

Additional information about CARB's architectural coatings program is available online.[39]

Agricultural and Structural Pesticides

The California Department of Pesticide Regulation (DPR) develops month-specific emission estimates for agricultural and structural pesticides. Each calendar year, DPR updates the inventory based on the Pesticides Use Report, which provides updated information from 1990 through the 2014 calendar year. Agricultural pesticide emission forecasts for 2015 and beyond are based on the average of the most recent five years. Growth for agricultural pesticides is based on CARB projections of farmland acres per FMMP, 2016. Growth for structural pesticides is based on DOF population growth projections, 2017.

Additional information about CARB's pesticides program is available online.[40]

Residential Wood Combustion

Residential Wood Combustion estimates are based on a 2011 CARB methodology. It reflects recent survey data on types of wood burning devices and wood consumption rates, updates to the 2002 U.S. EPA NEI emission factors and improved calculation approaches. The update reflects wood combustion surveys conducted by several local air districts including the Bay Area AQMD in 2007, South Coast AQMD in 2003 and 2006, Placer County APCD in 2007, San Joaquin Valley APCD in 2014, and Sacramento Metropolitan AQMD in 2007. Estimates were grown to 2014 based on DOF number of households per county. Emissions were grown from 2014 to 2016 according to historical residential wood consumption according to the Energy Information Administration. CARB assumes no growth beyond 2016 based on the relatively stagnant residential wood fuel use over the past decade (according to the American Community Survey and U.S. Energy Information Administration).

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[38] *https://ww2.arb.ca.gov/our-work/programs/consumer-products-program/consumer-commercial-product-surveys*

[39] *https://ww2.arb.ca.gov/solvent-evaporation-methodologies*

[40] *https://ww2.arb.ca.gov/solvent-evaporation-methodologies*

Additional information on CARB's residential wood combustion methodology is available online.[41]

Residential Natural Gas Combustion

Combustion of natural gas in the residential sector is broken down into four categories: space heating, water heating, cooking, and unspecified. The unspecified category includes the combustion of natural gas in appliances such as clothes dryers, barbecues, and water heaters used for pools, spas, and hot tubs.

The amount of natural gas consumed in the residential sector for each county was obtained from the California Energy Commission (CEC) report, "Quarterly Fuel and Energy Report, 1997 Residential Natural Gas Consumption." The amount of natural gas was apportioned into the four categories described above based on percentages from the CEC report, "Breakdown of California Natural Gas Usage by Appliance and by Utility Company for All Housing Types Combined." The emission factors for residential natural gas combustion were obtained from U.S. EPA's AP-42 5th Edition (1995).

Emissions were initially calculated for 1998 then grown to subsequent base years. Emissions were grown to 2012 using parameters developed by Pechan as documented in their report, "Development of Emission Growth Surrogates and Activity Projections Used in Forecasting Point and Area Source Emissions, Final Report," February 26, 2001. For cooking and unspecified, data on housing units were adjusted by Pechan using residential natural gas consumption projections from the Department of Energy's Annual Energy Outlook. Emissions were grown beyond 2012 using a forecast of gas use in the CEC's California Energy Demand 2014-2024 Final Forecast (2014) and population data from DOF (2014).

Additional information on CARB's residential natural gas methodology is available online.[42]

Residential Distillate Oil and Liquefied Petroleum Gas

The residential distillate oil/liquefied petroleum gas (LPG) category includes emissions occurring in the residential sector. Distillate oil for heating is generally used in older homes and remote areas where natural gas lines are not available. Activity is based on the number of housing units, population, and LPG and distillate oil capacities. The 1991 Fuels Report Working Paper published by the CEC was used to determine energy demand by fuel type in terms of the number of houses heated by a specific fuel in a particular area. Heating degree days (HDD) are used to estimate how many heating days are likely to occur in a particular area. This category uses emission factors from U.S. EPA's AP-42. The emissions were initially

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[41] *https://ww2.arb.ca.gov/miscellaneous-process-methodologies*

[42] *https://ww2.arb.ca.gov/miscellaneous-process-methodologies*

calculated in 1993 then grown to 2012 using housing unit data from the DOF. Emissions were grown beyond 2012 using a no growth profile.

Additional information on CARB's residential LPG methodology is available online.[43]

Livestock Husbandry

CARB staff updated the Livestock Husbandry methodology to reflect livestock population data based on the USDA's 2007 Census of Agriculture and ammonia emission factors for dairy support cattle. A seasonal adjustment was added to account for the suppression of dust emissions in months in which rainfall occurs. Future year growth profiles are based on CARB's projections of the Census of Agriculture's historical livestock population trends, 2012. No growth is assumed for dairy and feedlots. Agricultural land preparation and harvest operations were updated in 2016 with 2012 harvested acreage data from the USDA's National Agricultural Statistics Service (NASS). Future years are grown by FMMP Farmland Acreage, 2016.

Additional information on CARB's farming operations methodology is available online.[44, 45]

Building Construction Dust

Emission estimates for building construction dust were grown from CARB estimates developed in 2002. The emission factor used for the estimates of geologic dust emissions from construction activities is based on work performed by Midwest Research Institute (MRI) under contract to the PM10 Best Available Control Measure (BACM) working group in 1996. Estimates were grown to 2014 based on construction activity growth factors developed by Pechan. Future year growth is based on REMI economic forecasts, version 2.2.2.

Additional information on CARB's building construction dust methodology is available online.[46]

Road Construction Dust

Emission estimates for road construction dust were grown from CARB estimates developed in 1997. The emission factor used for the estimates of geologic dust emissions from construction activities is based on work performed by MRI under contract to the PM10 BACM working group in 1996. Estimates were grown to 2014 based on construction activity

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[43] *https://ww2.arb.ca.gov/miscellaneous-process-methodologies*

[44] *https://ww2.arb.ca.gov/carb-miscellaneous-process-methodologies-livestock*

[45] *https://ww2.arb.ca.gov/carb-miscellaneous-process-methodologies-farming-operations*

[46] *https://ww2.arb.ca.gov/carb-miscellaneous-process-methodologies-construction-and-demolition*

growth factors developed by Pechan. Future year growth is based on REMI economic forecasts, version 2.2.2.

Additional information on CARB's road construction dust methodology is available online.[47]

Paved Road Dust

Paved road dust emissions for 2012 were estimated using a CARB methodology consistent with the current U.S. EPA method (AP-42). The emission estimates are based on vehicle miles traveled (VMT) provided by the metropolitan planning organizations, California-specific silt loading values, VMT distribution (travel fractions) for various paved road categories. Emissions were grown using VMT projections from the metropolitan planning organizations in 2016.

Additional information on CARB's paved road dust methodology is available online.[48]

Unpaved Roads

Emissions for unpaved farm roads were updated based on CARB's methodology and 1993 harvested crop acreage from the California Department of Food and Agriculture. Emissions reflect crop specific VMT factors and an updated emission factor based on California test data conducted by the University of California, Davis (UC Davis) and the Desert Research Institute (DRI) in 1996. Agricultural unpaved road activity data are based on county specific harvested crop acreage and on crop specific VMT factors (VMT/acre/year). Growth is based on projected FMMP farmland acreage, 2016.

Emissions from unpaved nonfarm roads were estimated from 2008 unpaved road data collected from the California Statewide Local Streets and Roads Needs Assessment, Caltrans, and the local districts. The statewide emission factor for geologic dust emissions from vehicular travel on all unpaved roads is based on tests performed in the San Joaquin Valley by the UC Davis in 2001 and the DRI in 1996. Staff assumed no growth for this since it is assumed that existing unpaved roads will increasingly become paved as vehicle traffic on them increases, which counteracts any additional emissions from new unpaved roads.

Additional information on CARB's unpaved road methodology is available online.[49]

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[47] *https://ww3.arb.ca.gov/ei/areasrc/fullpdf/full7-8.pdf*

[48] *https://ww2.arb.ca.gov/carb-miscellaneous-process-methodologies-paved-road-dust*

[49] *https://ww2.arb.ca.gov/carb-miscellaneous-process-methodologies-unpaved-road-and-traffic-area-dust*

Fugitive Windblown Dust

Emissions for the fugitive windblown dust from open areas and non-pasture agricultural lands source category were estimated based on a 1997 CARB methodology for windblown dust from agricultural land (non-pasture) and pastureland with adjustments to the wind erosion equation. Growth for this category is based on projections of acreage from FMMP, 2016.

Emissions for the windblown dust from unpaved roads source category were estimated based on a 1997 CARB methodology reflecting unpaved road mileage and local parameters that affect wind erosion. The emission factor used for our estimates of geologic dust emissions from wind erosion of unpaved road material is based on an equation developed by the USDA. Activity data for the windblown dust emission factor equation is based on the acreage of erodible land. The estimates assume no growth.

Additional information about CARB's fugitive windblown dust methodology is available online.[50]

Structural and Automobile Fires

Emissions from structural and automobile fires were estimated based on a 1999 CARB methodology using the number of fires and the associated emission factors. Estimates for structural fires are calculated using the amount of the structure that is burned, the amount and content of the material burned, and emission factors derived from test data. Estimates for automobile fires are calculated using the weight of the car and components and composite emission factors derived from AP-42 emission factors. Growth is based on DOF population forecasts, 2017.

Additional information on CARB's structural and automobile fire methodology is available online.[51]

Managed Burning and Disposal

CARB updated the emissions inventory for managed burning and disposal to reflect burn data reported by local district staff for 2014. Emissions are calculated using crop specific emission factors and fuel loadings. Temporal profiles reflect monthly burn activity. Agricultural burning is grown by CARB projections of FMMP farmland acres, 2016. Non-agricultural open burning is grown by DOF population forecasts for rural counties and assumed no growth for other counties. Unspecified waste burning is grown by DOF

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[50] *https://ww2.arb.ca.gov/carb-miscellaneous-process-methodologies-fugitive-windblown-dust*

[51] *https://ww2.arb.ca.gov/miscellaneous-process-methodologies*

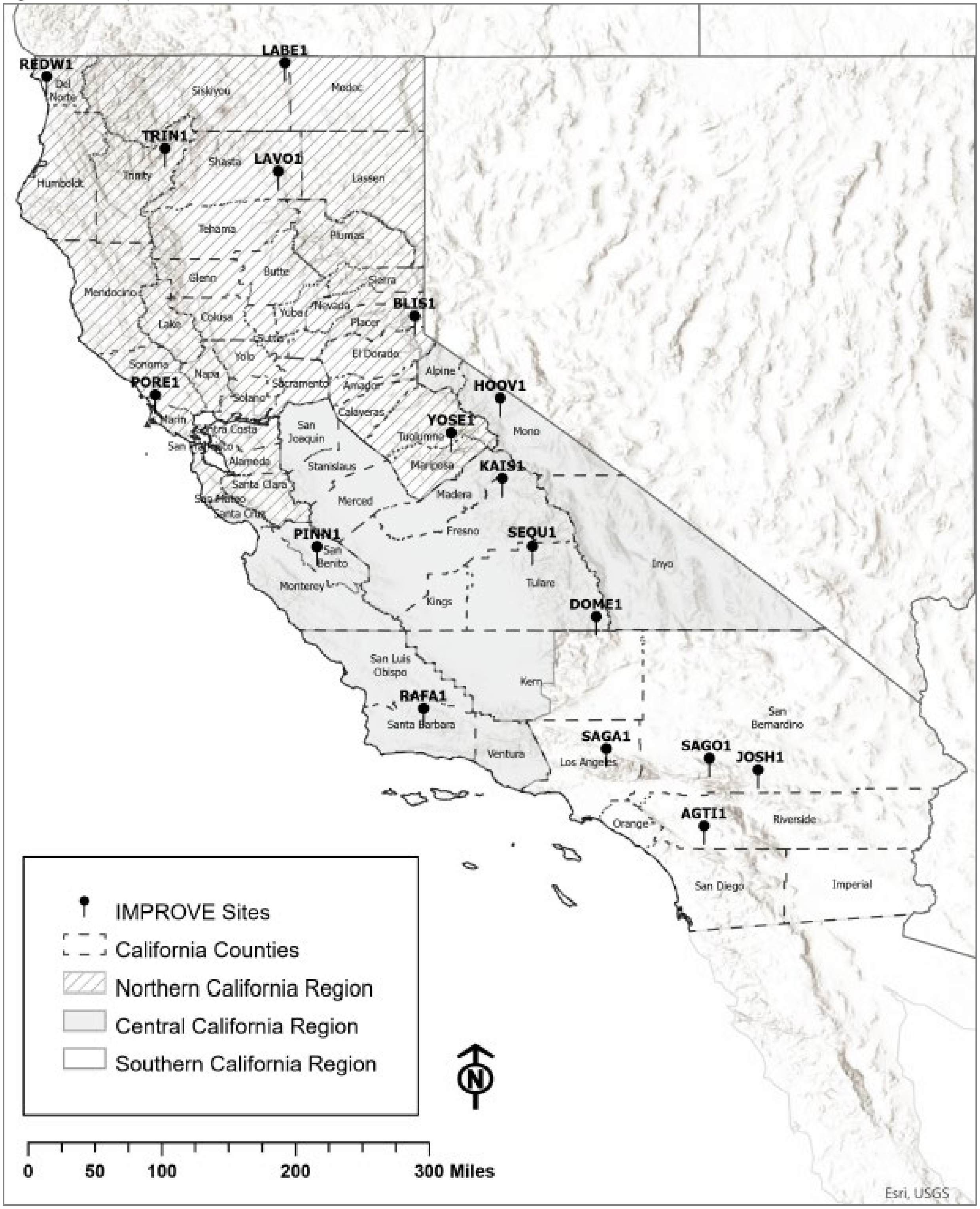
population forecasts, 2017. Weed abatement was grown to 2014 according to a growth factor developed by Pechan and assumed to be no growth for future years.

Additional information on CARB's managed burning methodology is available online.[52]

[52] *https://ww2.arb.ca.gov/miscellaneous-process-methodologies*

E. Statewide Emissions Inventories

Figure E-1: Map of California Counties and IMPROVE Sites in Northern, Central, and Southern California



Regional Emission Summaries

Table E-1: Summary of Haze Pollutant Emissions for the Northern California Region

	Ammonia (tpd)	NOx (tpd)	PM2.5 (tpd)	PM10 (tpd)	ROG (tpd)	SOx (tpd)
2014 Stationary	12	82	23	44	121	23
2014 Areawide	93	28	82	303	179	2
2014 Mobile	11	386	18	28	196	4
2014 Total	**116**	**496**	**123**	**375**	**496**	**29**
2028 Stationary	19	83	26	50	130	25
2028 Areawide	91	29	76	305	176	2
2028 Mobile	8	180	12	23	110	4
2028 Total	**117**	**292**	**115**	**378**	**416**	**32**

Table E-2: Summary of Haze Pollutant Emissions for the Central California Region

	Ammonia (tpd)	NOx (tpd)	PM2.5 (tpd)	PM10 (tpd)	ROG (tpd)	SOx (tpd)
2014 Stationary	18	62	12	22	113	9
2014 Areawide	332	14	67	357	203	1
2014 Mobile	7	299	15	21	114	2
2014 Total	**357**	**374**	**94**	**400**	**430**	**11**
2028 Stationary	19	53	12	25	114	9
2028 Areawide	320	13	66	357	207	1
2028 Mobile	5	132	10	17	61	2
2028 Total	**345**	**197**	**88**	**398**	**382**	**12**

Table E-3: Summary of Haze Pollutant Emissions for the Southern California Region

	Ammonia (tpd)	NOx (tpd)	PM2.5 (tpd)	PM10 (tpd)	ROG (tpd)	SOx (tpd)
2014 Stationary	40	105	25	53	136	15
2014 Areawide	107	26	95	539	186	1
2014 Mobile	23	606	34	53	307	7
2014 Total	**170**	**736**	**154**	**644**	**628**	**22**
2028 Stationary	41	120	31	67	151	18
2028 Areawide	106	19	103	578	198	1
2028 Mobile	16	285	26	47	170	7
2028 Total	**163**	**424**	**160**	**691**	**518**	**26**

Air Basins Emission Summaries

The locations of air basins in Northern, Central, and Southern California are shown in Figure 2-3, located in Chapter 2 of this Regional Haze Plan.

Table E-4: Summary of 2014 Haze Pollutant Emissions for the Air Basins in the Northern California Region

Emissions (tpd)	Lake County	Lake Tahoe	Mountain Counties	North Coast	Northeast Plateau	Sacramento Valley	San Francisco Bay
Ammonia - Stationary	2	0	0	5	0	3	2
Ammonia - Areawide	0	0	7	13	6	47	19
Ammonia - Mobile	0	0	1	0	0	3	6
Ammonia - Total	**2**	**0**	**8**	**19**	**7**	**53**	**27**
NOx - Stationary	0	0	6	4	2	30	40
NOx - Areawide	1	0	2	1	1	8	15
NOx - Mobile	4	4	28	21	13	122	194
NOx - Total	**5**	**4**	**35**	**27**	**16**	**160**	**249**
PM2.5 - Stationary	0	0	3	1	1	7	11
PM2.5 - Areawide	2	1	12	7	9	32	19
PM2.5 - Mobile	0	0	1	1	1	6	9
PM2.5 - Total	**3**	**1**	**16**	**10**	**10**	**45**	**38**
PM10 - Stationary	1	0	7	3	1	15	17
PM10 - Areawide	5	2	43	30	36	129	58
PM10 - Mobile	0	0	2	1	1	9	14
PM10 - Total	**6**	**3**	**52**	**34**	**38**	**153**	**89**
ROG - Stationary	1	0	5	6	1	34	73
ROG - Areawide	3	2	19	15	15	58	68
ROG - Mobile	4	3	20	12	5	59	93
ROG - Total	**8**	**5**	**44**	**33**	**21**	**151**	**234**
SOx - Stationary	0	0	1	1	0	2	19
SOx - Areawide	0	0	0	0	0	1	0
SOx - Mobile	0	0	0	0	0	1	3
SOx - Total	**0**	**0**	**2**	**1**	**1**	**3**	**22**

Table E-5: Summary of 2028 Haze Pollutant Emissions for the Air Basins in the Northern California Region

Emissions (tpd)	Lake County	Lake Tahoe	Mountain Counties	North Coast	Northeast Plateau	Sacramento Valley	San Francisco Bay
Ammonia - Stationary	4	0	0	9	1	4	2
Ammonia - Areawide	0	0	6	13	6	45	21
Ammonia - Mobile	0	0	0	0	0	2	4
Ammonia - Total	5	0	7	22	6	51	27
NOx - Stationary	0	0	6	4	1	28	44
NOx - Areawide	1	0	2	1	1	7	18
NOx - Mobile	2	2	11	7	5	51	102
NOx - Total	3	2	18	12	7	87	163
PM2.5 - Stationary	1	0	3	2	1	8	12
PM2.5 - Areawide	2	1	11	6	8	28	20
PM2.5 - Mobile	0	0	1	1	0	4	6
PM2.5 - Total	3	1	14	8	10	40	39
PM10 - Stationary	1	0	6	3	2	19	19
PM10 - Areawide	5	2	43	29	36	126	64
PM10 - Mobile	0	0	1	1	0	7	13
PM10 - Total	6	2	50	33	38	153	96
ROG - Stationary	1	0	6	6	1	34	81
ROG - Areawide	3	2	17	13	13	53	76
ROG - Mobile	2	2	10	7	3	31	55
ROG - Total	6	4	33	26	17	118	212
SOx - Stationary	0	0	1	1	0	2	21
SOx - Areawide	0	0	0	0	0	1	0
SOx - Mobile	0	0	0	0	0	1	3
SOx - Total	0	0	1	1	0	3	25

Table E-6: Summary of 2014 Haze Pollutant Emissions for the Air Basins in the Central California Region

Emissions (tpd)	Great Basin Valleys	North Central Coast	South Central Coast	San Joaquin Valley
Ammonia - Stationary	0	2	2	13
Ammonia - Areawide	1	11	10	311
Ammonia - Mobile	0	1	1	4
Ammonia - Total	**1**	**13**	**14**	**328**
NOx - Stationary	1	17	8	36
NOx - Areawide	0	2	3	8
NOx - Mobile	4	26	44	224
NOx - Total	**5**	**46**	**55**	**268**
PM2.5 - Stationary	1	2	1	9
PM2.5 - Areawide	6	9	8	44
PM2.5 - Mobile	0	1	2	11
PM2.5 - Total	**7**	**12**	**11**	**64**
PM10 - Stationary	1	5	2	14
PM10 - Areawide	47	37	32	240
PM10 - Mobile	0	2	4	15
PM10 - Total	**49**	**44**	**38**	**270**
ROG - Stationary	0	11	22	80
ROG - Areawide	3	23	26	151
ROG - Mobile	3	13	26	72
ROG - Total	**6**	**47**	**74**	**302**
SOx - Stationary	1	1	2	6
SOx - Areawide	0	0	0	0
SOx - Mobile	0	0	1	1
SOx - Total	**1**	**1**	**2**	**7**

Table E-7: Summary of 2028 Haze Pollutant Emissions for the Air Basins in the Central California Region

Emissions (tpd)	Great Basin Valleys	North Central Coast	South Central Coast	San Joaquin Valley
Ammonia - Stationary	0	2	3	14
Ammonia - Areawide	1	10	9	300
Ammonia - Mobile	0	0	1	3
Ammonia - Total	**1**	**13**	**13**	**317**
NOx - Stationary	1	18	7	27
NOx - Areawide	0	2	3	8
NOx - Mobile	1	11	19	101
NOx - Total	**2**	**31**	**29**	**136**
PM2.5 - Stationary	1	2	1	9
PM2.5 - Areawide	6	9	8	44
PM2.5 - Mobile	0	1	2	7
PM2.5 - Total	**7**	**11**	**11**	**59**
PM10 - Stationary	2	6	2	15
PM10 - Areawide	47	37	34	238
PM10 - Mobile	0	2	3	12
PM10 - Total	**49**	**45**	**39**	**265**
ROG - Stationary	0	11	22	81
ROG - Areawide	3	22	26	156
ROG - Mobile	2	7	14	38
ROG - Total	**5**	**40**	**62**	**275**
SOx - Stationary	1	1	1	6
SOx - Areawide	0	0	0	0
SOx - Mobile	0	0	1	1
SOx - Total	**1**	**1**	**2**	**7**

Table E-8: Summary of 2014 Haze Pollutant Emissions for the Air Basins in the Southern California Region

Emissions (tpd)	Mojave Desert	Salton Sea	San Diego County	South Coast
Ammonia - Stationary	2	2	1	35
Ammonia - Areawide	16	43	9	39
Ammonia - Mobile	2	1	4	17
Ammonia - Total	**19**	**46**	**14**	**91**
NOx - Stationary	51	3	5	46
NOx - Areawide	2	1	3	20
NOx - Mobile	96	40	85	385
NOx - Total	**149**	**44**	**93**	**451**
PM2.5 - Stationary	9	1	3	13
PM2.5 - Areawide	15	40	11	30
PM2.5 - Mobile	6	2	6	19
PM2.5 - Total	**30**	**43**	**19**	**62**
PM10 - Stationary	22	4	8	18
PM10 - Areawide	87	299	54	99
PM10 - Mobile	8	3	9	33
PM10 - Total	**117**	**306**	**71**	**150**
ROG - Stationary	15	4	31	86
ROG - Areawide	15	16	35	120
ROG - Mobile	29	13	54	210
ROG - Total	**59**	**33**	**121**	**416**
SOx - Stationary	5	0	0	9
SOx - Areawide	0	0	0	1
SOx - Mobile	1	0	1	5
SOx - Total	**6**	**1**	**1**	**15**

Table E-9: Summary of 2028 Haze Pollutant Emissions for the Air Basins in the Southern California Region

Emissions (tpd)	Mojave Desert	Salton Sea	San Diego County	South Coast
Ammonia - Stationary	2	2	1	36
Ammonia - Areawide	15	44	9	37
Ammonia - Mobile	1	1	3	12
Ammonia - Total	**19**	**47**	**13**	**85**
NOx - Stationary	72	3	4	40
NOx - Areawide	2	1	2	13
NOx - Mobile	44	23	39	180
NOx - Total	**118**	**27**	**45**	**234**
PM2.5 - Stationary	12	1	3	15
PM2.5 - Areawide	18	41	11	33
PM2.5 - Mobile	5	3	5	14
PM2.5 - Total	**35**	**45**	**18**	**62**
PM10 - Stationary	32	4	10	21
PM10 - Areawide	103	303	58	113
PM10 - Mobile	7	4	8	28
PM10 - Total	**142**	**311**	**76**	**163**
ROG - Stationary	19	5	31	95
ROG - Areawide	17	17	35	129
ROG - Mobile	17	10	30	112
ROG - Total	**54**	**32**	**96**	**336**
SOx - Stationary	7	0	0	10
SOx - Areawide	0	0	0	1
SOx - Mobile	1	0	1	6
SOx - Total	**8**	**1**	**1**	**16**

County Emissions Summaries

Table E-10: Summary of Ammonia Emissions for Counties in the Air Basins in the Northern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alameda	0.0	2.8	1.5	**4.4**	0.0	3.1	1.1	**4.2**
Amador	0.0	0.6	0.1	**0.6**	0.0	0.5	0.0	**0.5**
Butte	0.1	4.9	0.2	**5.2**	0.2	4.7	0.2	**5.0**
Calaveras	0.0	0.8	0.0	**0.9**	0.0	0.7	0.0	**0.7**
Colusa	0.2	5.8	0.1	**6.1**	0.2	5.7	0.1	**6.0**
Contra Costa	0.0	3.0	0.9	**4.0**	0.0	3.3	0.6	**4.0**
Del Norte	0.0	5.2	0.0	**5.3**	0.0	5.4	0.0	**5.4**
El Dorado	0.0	0.7	0.2	**0.9**	0.0	0.7	0.2	**0.8**
Glenn	0.0	5.4	0.1	**5.4**	0.0	5.1	0.0	**5.2**
Humboldt	2.5	3.4	0.1	**6.0**	2.5	3.2	0.1	**5.8**
Lake	1.8	0.5	0.1	**2.3**	4.1	0.4	0.0	**4.6**
Lassen	0.4	1.6	0.1	**2.1**	0.5	1.5	0.0	**2.0**
Marin	0.1	2.2	0.2	**2.6**	0.2	2.1	0.2	**2.4**
Mariposa	0.0	0.7	0.0	**0.7**	0.0	0.7	0.0	**0.7**
Mendocino	0.0	0.9	0.1	**1.0**	0.0	0.8	0.1	**1.0**
Modoc	0.0	2.1	0.0	**2.1**	0.0	1.7	0.0	**1.7**
Napa	0.1	0.5	0.1	**0.7**	0.1	0.5	0.1	**0.7**
Nevada	0.0	0.7	0.1	**0.8**	0.0	0.6	0.1	**0.7**
Placer	0.2	1.5	0.5	**2.2**	0.2	1.5	0.4	**2.1**
Plumas	0.0	0.5	0.0	**0.6**	0.0	0.5	0.0	**0.6**
Sacramento	1.8	9.0	1.5	**12.3**	2.0	9.0	1.1	**12.1**
San Francisco	0.0	1.4	0.4	**1.7**	0.0	1.7	0.2	**1.8**
San Mateo	0.0	1.3	0.6	**1.9**	0.0	1.4	0.4	**1.9**
Santa Clara	1.0	3.5	1.6	**6.0**	1.1	3.8	1.1	**6.1**
Shasta	0.1	3.2	0.2	**3.6**	0.2	3.0	0.2	**3.3**
Sierra	0.0	0.1	0.0	**0.1**	0.0	0.1	0.0	**0.1**
Siskiyou	0.0	2.7	0.1	**2.9**	0.0	2.4	0.1	**2.6**
Solano	4.7	0.5	0.3	**5.5**	4.7	0.4	0.4	**5.4**
Sonoma	2.7	6.4	0.4	**9.5**	6.2	6.4	0.3	**12.9**
Sutter	0.2	3.5	0.1	**3.8**	0.1	3.4	0.1	**3.6**
Tehama	0.0	2.4	0.1	**2.5**	0.0	2.1	0.1	**2.2**
Trinity	0.0	0.1	0.0	**0.2**	0.0	0.1	0.0	**0.1**
Tuolumne	0.0	2.2	0.1	**2.2**	0.0	2.0	0.0	**2.1**
Yolo	0.1	7.4	0.3	**7.8**	0.1	6.8	0.2	**7.2**
Yuba	0.2	1.3	0.1	**1.5**	0.2	1.2	0.1	**1.4**

Table E-11: Summary of NOx Emissions for Counties in the Air Basins in the Northern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alameda	4.2	3.0	48.5	**55.8**	3.3	3.5	23.9	**30.6**
Amador	1.8	0.3	1.7	**3.8**	1.8	0.3	0.7	**2.8**
Butte	1.4	1.1	12.8	**15.3**	1.0	1.0	5.3	**7.4**
Calaveras	0.1	0.2	2.3	**2.6**	0.2	0.2	0.9	**1.3**
Colusa	4.4	0.4	5.5	**10.3**	4.0	0.4	2.3	**6.7**
Contra Costa	16.2	2.4	26.1	**44.7**	18.4	2.8	12.6	**33.8**
Del Norte	0.1	0.1	3.8	**4.0**	0.0	0.1	3.9	**4.0**
El Dorado	0.2	0.4	6.4	**7.0**	0.2	0.3	2.7	**3.2**
Glenn	3.3	0.4	5.6	**9.2**	2.3	0.3	2.3	**5.0**
Humboldt	3.6	0.6	7.8	**11.9**	2.9	0.5	2.6	**6.0**
Lake	0.4	0.6	3.6	**4.7**	0.4	0.6	1.5	**2.6**
Lassen	1.0	0.1	3.3	**4.5**	0.9	0.1	1.1	**2.2**
Marin	0.5	0.8	6.2	**7.4**	0.5	0.9	2.8	**4.2**
Mariposa	0.0	0.1	0.9	**0.9**	0.0	0.1	0.4	**0.4**
Mendocino	0.4	0.3	7.3	**8.1**	0.5	0.3	2.6	**3.3**
Modoc	0.2	0.0	1.9	**2.1**	0.1	0.0	0.8	**0.8**
Napa	0.3	0.3	5.2	**5.8**	0.3	0.4	2.1	**2.8**
Nevada	0.1	0.4	6.0	**6.6**	0.1	0.4	2.4	**3.0**
Placer	3.2	0.9	17.4	**21.6**	3.8	0.9	7.6	**12.4**
Plumas	2.1	0.1	2.8	**5.0**	2.4	0.1	1.0	**3.5**
Sacramento	2.8	3.0	38.1	**43.8**	2.6	2.3	15.5	**20.4**
San Francisco	1.4	1.9	25.3	**28.7**	1.4	2.2	18.9	**22.6**
San Mateo	1.5	1.7	34.4	**37.7**	1.8	2.0	34.6	**38.4**
Santa Clara	11.0	3.5	39.6	**54.1**	12.6	4.0	15.8	**32.5**
Shasta	7.4	0.8	13.3	**21.4**	8.5	0.7	5.3	**14.5**
Sierra	0.0	0.0	0.4	**0.5**	0.0	0.0	0.2	**0.2**
Siskiyou	0.4	0.5	8.1	**9.0**	0.3	0.5	3.1	**3.9**
Solano	4.7	1.0	18.3	**23.9**	5.1	1.0	8.8	**15.0**
Sonoma	0.8	1.3	14.2	**16.2**	0.7	1.4	5.5	**7.6**
Sutter	3.1	0.5	7.0	**10.6**	1.9	0.5	3.0	**5.4**
Tehama	1.1	0.3	7.9	**9.2**	0.8	0.3	3.3	**4.4**
Trinity	0.0	0.0	1.8	**1.9**	0.0	0.0	0.6	**0.7**
Tuolumne	1.1	0.2	3.0	**4.4**	1.2	0.2	1.2	**2.6**
Yolo	2.7	0.5	10.1	**13.3**	2.5	0.4	4.4	**7.3**
Yuba	0.5	0.2	4.2	**4.9**	0.4	0.2	1.9	**2.5**

Table E-12: Summary of PM2.5 Emissions for Counties in the Air Basins in the Northern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alameda	2.3	3.1	2.2	**7.6**	2.3	3.4	1.5	**7.3**
Amador	1.7	1.2	0.1	**3.0**	1.5	1.0	0.0	**2.6**
Butte	0.9	4.4	0.6	**5.8**	1.1	3.7	0.3	**5.1**
Calaveras	0.0	1.2	0.1	**1.3**	0.0	1.0	0.1	**1.1**
Colusa	0.3	2.6	0.3	**3.1**	0.3	2.5	0.1	**3.0**
Contra Costa	5.2	3.6	1.3	**10.0**	6.0	3.8	1.0	**10.7**
Del Norte	0.0	0.9	0.1	**1.0**	0.0	0.8	0.0	**0.9**
El Dorado	0.2	2.2	0.4	**2.8**	0.2	1.8	0.3	**2.3**
Glenn	0.4	2.0	0.3	**2.7**	0.4	2.0	0.1	**2.5**
Humboldt	0.9	3.1	0.3	**4.4**	0.8	2.7	0.2	**3.7**
Lake	0.4	2.2	0.2	**2.8**	0.6	2.0	0.1	**2.8**
Lassen	0.5	2.4	0.1	**3.0**	0.6	2.3	0.1	**2.9**
Marin	0.2	1.0	0.4	**1.6**	0.3	1.0	0.3	**1.6**
Mariposa	0.0	0.8	0.1	**0.9**	0.0	0.8	0.0	**0.8**
Mendocino	0.2	1.5	0.3	**2.1**	0.3	1.2	0.2	**1.6**
Modoc	0.0	1.4	0.1	**1.5**	0.0	1.4	0.0	**1.4**
Napa	0.1	0.8	0.3	**1.2**	0.1	0.8	0.2	**1.1**
Nevada	0.1	1.5	0.2	**1.9**	0.1	1.3	0.1	**1.5**
Placer	1.0	3.2	0.8	**5.0**	1.2	2.9	0.5	**4.6**
Plumas	0.4	2.1	0.1	**2.5**	0.4	1.9	0.1	**2.4**
Sacramento	0.8	8.0	1.8	**10.5**	0.8	6.3	1.3	**8.4**
San Francisco	0.2	1.2	1.0	**2.4**	0.2	1.4	0.6	**2.3**
San Mateo	0.6	1.4	0.9	**2.9**	0.7	1.6	0.7	**3.0**
Santa Clara	1.2	4.3	2.0	**7.5**	1.5	4.8	1.5	**7.7**
Shasta	1.2	3.9	0.6	**5.6**	1.4	3.5	0.3	**5.2**
Sierra	0.1	0.7	0.0	**0.8**	0.1	0.7	0.0	**0.8**
Siskiyou	0.4	4.8	0.3	**5.5**	0.7	4.5	0.2	**5.4**
Solano	0.7	2.5	0.8	**4.0**	0.8	2.3	0.5	**3.6**
Sonoma	0.6	2.7	0.7	**4.0**	0.9	2.7	0.5	**4.0**
Sutter	0.7	2.3	0.3	**3.3**	0.8	2.1	0.2	**3.0**
Tehama	0.4	1.7	0.3	**2.4**	0.5	1.5	0.2	**2.2**
Trinity	0.0	0.8	0.1	**0.9**	0.0	0.8	0.0	**0.8**
Tuolumne	0.5	2.0	0.2	**2.7**	0.4	1.8	0.1	**2.3**
Yolo	0.9	3.5	0.5	**4.9**	1.1	3.2	0.3	**4.6**
Yuba	0.1	1.2	0.2	**1.5**	0.2	1.0	0.2	**1.3**

Table E-13: Summary of PM10 Emissions for Counties in the Air Basins in the Northern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alameda	4.5	10.3	3.5	**18.4**	4.9	11.8	3.1	**19.8**
Amador	3.2	2.2	0.1	**5.5**	2.6	2.1	0.1	**4.8**
Butte	2.8	16.2	0.8	**19.8**	3.7	15.5	0.5	**19.7**
Calaveras	0.1	3.5	0.2	**3.7**	0.0	3.3	0.1	**3.5**
Colusa	0.9	13.5	0.4	**14.7**	1.1	13.4	0.2	**14.7**
Contra Costa	6.1	9.3	2.1	**17.5**	7.1	10.2	1.9	**19.2**
Del Norte	0.0	4.0	0.1	**4.2**	0.0	4.0	0.1	**4.1**
El Dorado	0.3	8.8	0.6	**9.7**	0.3	8.5	0.5	**9.4**
Glenn	1.0	10.2	0.4	**11.6**	1.3	10.1	0.2	**11.6**
Humboldt	1.3	11.6	0.5	**13.3**	1.2	11.2	0.4	**12.8**
Lake	1.0	4.7	0.4	**6.0**	1.3	4.6	0.2	**6.1**
Lassen	0.6	9.4	0.2	**10.2**	0.8	9.3	0.1	**10.2**
Marin	1.0	2.8	0.6	**4.4**	1.2	3.0	0.5	**4.6**
Mariposa	0.0	2.2	0.1	**2.3**	0.0	2.2	0.1	**2.3**
Mendocino	0.3	5.0	0.5	**5.8**	0.4	4.8	0.4	**5.5**
Modoc	0.0	9.8	0.1	**9.9**	0.0	9.7	0.1	**9.8**
Napa	0.2	2.7	0.4	**3.3**	0.3	2.8	0.3	**3.4**
Nevada	0.8	5.9	0.4	**7.0**	0.5	5.7	0.3	**6.5**
Placer	1.9	12.0	1.2	**15.1**	2.4	12.7	1.0	**16.2**
Plumas	0.6	8.9	0.2	**9.7**	0.6	8.8	0.1	**9.5**
Sacramento	1.7	22.0	3.1	**26.8**	2.0	21.5	2.6	**26.2**
San Francisco	0.3	3.1	1.4	**4.8**	0.4	3.6	1.0	**5.1**
San Mateo	0.9	4.9	1.4	**7.3**	1.1	5.5	1.4	**8.0**
Santa Clara	2.1	14.7	3.4	**20.1**	2.5	16.5	3.0	**22.0**
Shasta	1.7	11.3	0.9	**13.9**	2.1	11.1	0.6	**13.8**
Sierra	0.1	3.9	0.1	**4.1**	0.1	3.9	0.0	**4.1**
Siskiyou	0.6	16.9	0.4	**18.0**	1.0	16.8	0.3	**18.1**
Solano	1.1	10.3	1.3	**12.7**	1.3	10.4	1.0	**12.7**
Sonoma	1.6	7.4	1.1	**10.1**	2.1	7.7	0.9	**10.8**
Sutter	1.9	10.5	0.4	**12.8**	2.5	10.1	0.3	**12.9**
Tehama	0.7	7.8	0.5	**9.0**	0.9	7.7	0.3	**8.9**
Trinity	0.1	6.2	0.1	**6.4**	0.1	6.2	0.1	**6.4**
Tuolumne	1.5	4.9	0.3	**6.8**	1.2	4.8	0.2	**6.2**
Yolo	2.1	21.2	0.7	**24.1**	2.7	21.1	0.5	**24.3**
Yuba	0.3	4.5	0.3	**5.1**	0.4	4.3	0.2	**4.9**

Table E-14: Summary of ROG Emissions for Counties in the Air Basins in the Northern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alameda	13.5	14.2	20.9	**48.5**	14.9	15.9	11.5	**42.4**
Amador	1.5	1.9	1.3	**4.7**	1.4	1.7	0.7	**3.7**
Butte	2.0	5.8	5.2	**13.0**	2.0	5.5	2.6	**10.1**
Calaveras	0.2	2.3	2.3	**4.8**	0.2	2.0	1.2	**3.3**
Colusa	2.4	2.3	1.4	**6.1**	1.5	2.3	0.7	**4.4**
Contra Costa	25.5	10.1	13.4	**48.9**	28.7	11.4	7.4	**47.5**
Del Norte	0.2	1.3	0.7	**2.2**	0.2	1.2	0.4	**1.8**
El Dorado	0.9	4.0	5.2	**10.2**	2.0	3.4	3.1	**8.4**
Glenn	2.1	3.1	1.6	**6.9**	1.5	3.0	0.8	**5.2**
Humboldt	3.1	5.9	3.8	**12.8**	2.6	5.3	2.2	**10.0**
Lake	0.9	2.9	4.0	**7.9**	1.2	2.8	1.9	**6.0**
Lassen	0.3	3.8	1.6	**5.6**	0.3	3.5	0.8	**4.6**
Marin	1.6	3.2	5.0	**9.8**	1.7	3.3	2.8	**7.8**
Mariposa	0.1	1.8	1.2	**3.0**	0.1	1.6	0.6	**2.3**
Mendocino	1.4	3.6	3.7	**8.6**	1.3	3.2	2.0	**6.4**
Modoc	0.1	2.4	0.6	**3.2**	0.1	1.9	0.3	**2.3**
Napa	1.4	1.6	3.3	**6.3**	1.5	1.7	1.7	**4.9**
Nevada	0.9	2.4	2.9	**6.2**	0.9	2.0	1.6	**4.4**
Placer	5.4	5.7	8.4	**19.6**	6.1	5.5	4.3	**15.8**
Plumas	0.9	2.4	1.7	**5.0**	1.0	2.1	0.9	**4.0**
Sacramento	9.3	21.6	21.6	**52.5**	10.4	19.2	11.3	**41.0**
San Francisco	4.4	7.2	7.9	**19.6**	5.0	8.1	5.4	**18.5**
San Mateo	5.2	6.6	11.0	**22.8**	5.7	7.3	8.7	**21.6**
Santa Clara	13.8	16.9	20.7	**51.4**	15.6	19.1	11.8	**46.5**
Shasta	1.7	6.7	6.7	**15.1**	2.0	6.1	3.3	**11.4**
Sierra	0.1	0.8	0.8	**1.7**	0.0	0.8	0.5	**1.3**
Siskiyou	0.8	8.6	3.1	**12.5**	0.9	7.8	1.6	**10.3**
Solano	8.3	5.4	8.1	**21.9**	9.7	5.7	4.4	**19.7**
Sonoma	4.1	8.3	8.9	**21.3**	4.4	8.5	4.7	**17.6**
Sutter	3.5	2.3	2.3	**8.1**	2.4	2.2	1.3	**5.9**
Tehama	1.4	3.3	3.4	**8.0**	1.2	2.7	1.9	**5.8**
Trinity	0.1	1.0	1.3	**2.4**	0.1	0.9	0.6	**1.6**
Tuolumne	0.5	3.3	4.2	**8.1**	0.5	3.0	2.1	**5.6**
Yolo	2.8	3.5	3.8	**10.2**	2.8	3.3	1.9	**8.0**
Yuba	0.6	2.3	3.9	**6.9**	0.7	2.3	2.7	**5.7**

Table E-15: Summary of SOx Emissions for Counties in the Air Basins in the Northern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alameda	1.4	0.1	0.5	**2.0**	0.8	0.1	0.7	**1.6**
Amador	0.1	0.0	0.0	**0.1**	0.1	0.0	0.0	**0.1**
Butte	0.0	0.1	0.1	**0.2**	0.0	0.1	0.1	**0.2**
Calaveras	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**
Colusa	0.3	0.1	0.0	**0.4**	0.5	0.1	0.0	**0.6**
Contra Costa	14.1	0.1	0.7	**14.9**	16.3	0.1	0.8	**17.1**
Del Norte	0.0	0.0	0.0	**0.1**	0.0	0.0	0.0	**0.0**
El Dorado	0.0	0.1	0.1	**0.2**	0.0	0.1	0.1	**0.1**
Glenn	0.2	0.1	0.0	**0.2**	0.2	0.1	0.0	**0.3**
Humboldt	0.3	0.1	0.0	**0.4**	0.2	0.1	0.0	**0.3**
Lake	0.2	0.1	0.0	**0.4**	0.3	0.1	0.0	**0.4**
Lassen	0.1	0.1	0.0	**0.3**	0.1	0.1	0.0	**0.2**
Marin	0.2	0.0	0.0	**0.2**	0.2	0.0	0.0	**0.2**
Mariposa	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**
Mendocino	0.4	0.1	2.1	**2.6**	0.5	0.1	1.6	**2.1**
Modoc	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**
Napa	0.0	0.0	0.0	**0.1**	0.0	0.0	0.0	**0.1**
Nevada	0.3	0.1	0.0	**0.4**	0.2	0.1	0.0	**0.3**
Placer	0.1	0.1	0.1	**0.3**	0.1	0.1	0.1	**0.3**
Plumas	0.2	0.1	0.0	**0.3**	0.3	0.1	0.0	**0.3**
Sacramento	0.4	0.1	0.4	**0.8**	0.4	0.1	0.4	**0.9**
San Francisco	0.1	0.1	0.2	**0.3**	0.1	0.1	0.3	**0.4**
San Mateo	0.2	0.0	0.8	**1.0**	0.3	0.0	1.0	**1.3**
Santa Clara	2.7	0.1	0.3	**3.1**	3.2	0.1	0.3	**3.6**
Shasta	0.1	0.1	0.1	**0.3**	0.1	0.1	0.1	**0.3**
Sierra	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**
Siskiyou	0.0	0.2	0.0	**0.2**	0.0	0.2	0.0	**0.2**
Solano	0.4	0.0	0.2	**0.6**	0.4	0.0	0.2	**0.7**
Sonoma	0.1	0.1	0.1	**0.3**	0.2	0.1	0.0	**0.3**
Sutter	0.1	0.1	0.0	**0.1**	0.1	0.1	0.0	**0.1**
Tehama	0.0	0.0	0.0	**0.1**	0.0	0.0	0.0	**0.1**
Trinity	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**
Tuolumne	0.4	0.1	0.0	**0.5**	0.4	0.1	0.0	**0.5**
Yolo	0.2	0.0	0.0	**0.3**	0.3	0.0	0.0	**0.4**
Yuba	0.1	0.0	0.1	**0.2**	0.1	0.0	0.1	**0.2**

Table E-16: Summary of Ammonia Emissions for Counties in the Air Basins in the Central California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alpine	0.0	0.1	0.0	**0.1**	0.0	0.1	0.0	**0.1**
Fresno	1.2	33.1	1.0	**35.3**	1.3	31.1	0.8	**33.2**
Inyo	0.1	0.5	0.1	**0.6**	0.2	0.4	0.0	**0.6**
Kern*	5.9	45.5	0.9	**52.3**	6.4	42.8	0.8	**49.9**
Kings	0.2	29.4	0.2	**29.8**	0.3	26.6	0.1	**26.9**
Madera	0.1	11.5	0.2	**11.8**	0.1	10.8	0.2	**11.1**
Merced	1.1	37.0	0.3	**38.4**	1.2	37.2	0.2	**38.6**
Mono	0.1	0.4	0.0	**0.5**	0.1	0.3	0.0	**0.3**
Monterey	0.9	8.6	0.5	**10.0**	0.9	8.5	0.3	**9.8**
San Benito	0.8	1.3	0.1	**2.2**	1.1	1.1	0.0	**2.3**
San Joaquin	1.4	65.1	0.8	**67.4**	1.4	62.6	0.7	**64.6**
San Luis Obispo	0.1	3.3	0.3	**3.7**	0.1	2.7	0.2	**3.0**
Santa Barbara	0.4	1.0	0.4	**1.8**	0.5	1.0	0.2	**1.7**
Santa Cruz	0.1	0.8	0.2	**1.1**	0.1	0.8	0.1	**1.0**
Stanislaus	2.0	30.3	0.5	**32.9**	2.0	30.3	0.4	**32.6**
Tulare	1.3	58.9	0.5	**60.7**	1.3	58.5	0.3	**60.2**
Ventura	1.9	5.7	0.8	**8.4**	2.4	5.7	0.6	**8.6**

**Portion of Kern County in San Joaquin Valley Air Basin*

Table E-17: Summary of NOx Emissions for Counties in the Air Basins in the Central California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alpine	0.1	0.0	0.0	**0.1**	0.1	0.0	0.0	**0.1**
Fresno	7.5	2.2	46.1	**55.8**	6.0	2.0	21.8	**29.8**
Inyo	0.4	0.0	2.2	**2.7**	0.4	0.0	0.8	**1.2**
Kern*	10.0	1.2	50.7	**61.8**	6.0	1.2	22.7	**29.9**
Kings	1.4	0.2	12.4	**14.0**	0.9	0.2	6.4	**7.5**
Madera	2.4	0.5	12.5	**15.4**	2.1	0.5	5.3	**7.8**
Merced	1.8	0.6	22.8	**25.1**	1.2	0.5	9.9	**11.6**
Mono	0.2	0.0	1.4	**1.7**	0.1	0.0	0.5	**0.7**
Monterey	11.3	1.5	15.2	**27.9**	11.3	1.4	6.2	**18.9**
San Benito	0.7	0.1	4.6	**5.5**	0.6	0.2	2.0	**2.8**
San Joaquin	6.6	1.4	34.2	**42.2**	6.1	1.3	15.4	**22.7**
San Luis Obispo	1.7	0.8	10.5	**13.0**	1.8	0.7	3.8	**6.4**
Santa Barbara	4.0	0.7	66.6	**71.3**	3.6	0.6	81.7	**85.8**
Santa Cruz	5.2	0.7	6.6	**12.5**	6.5	0.6	2.3	**9.4**
Stanislaus	3.6	1.0	21.3	**25.9**	3.1	0.9	9.6	**13.7**
Tulare	2.7	1.1	24.3	**28.0**	1.4	1.0	10.3	**12.7**
Ventura	2.0	1.6	20.1	**23.7**	1.8	1.4	9.4	**12.6**

**Portion of Kern County in San Joaquin Valley Air Basin*

Table E-18: Summary of PM2.5 Emissions for Counties in the Air Basins in the Central California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alpine	0.0	0.1	0.0	**0.2**	0.0	0.1	0.0	**0.1**
Fresno	1.6	11.2	2.2	**15.0**	1.6	11.2	1.4	**14.2**
Inyo	0.6	4.3	0.1	**5.0**	0.9	4.3	0.1	**5.2**
Kern*	3.8	5.9	2.1	**11.7**	2.9	6.0	1.1	**10.0**
Kings	0.2	3.4	1.5	**5.1**	0.3	2.8	1.3	**4.3**
Madera	0.5	2.9	0.6	**4.0**	0.6	2.9	0.3	**3.8**
Merced	0.3	4.7	1.0	**6.0**	0.3	4.8	0.5	**5.6**
Mono	0.0	1.4	0.1	**1.5**	0.0	1.4	0.1	**1.5**
Monterey	1.1	6.5	0.8	**8.4**	1.1	6.2	0.5	**7.8**
San Benito	0.3	1.0	0.2	**1.4**	0.4	0.9	0.1	**1.4**
San Joaquin	1.2	5.0	1.7	**7.8**	1.3	5.0	1.0	**7.4**
San Luis Obispo	0.2	2.8	0.5	**3.5**	0.2	2.4	0.3	**3.0**
Santa Barbara	0.4	1.0	0.6	**2.1**	0.4	1.1	0.4	**1.9**
Santa Cruz	0.3	2.0	0.3	**2.6**	0.4	1.6	0.2	**2.2**
Stanislaus	0.9	4.7	1.0	**6.5**	0.9	4.9	0.6	**6.4**
Tulare	0.5	5.9	1.2	**7.5**	0.6	5.9	0.7	**7.1**
Ventura	0.4	3.8	1.3	**5.5**	0.5	4.2	1.1	**5.8**

**Portion of Kern County in San Joaquin Valley Air Basin*

Table E-19: Summary of PM10 Emissions for Counties in the Air Basins in the Central California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alpine	0.0	1.2	0.0	**1.3**	0.0	1.2	0.0	**1.3**
Fresno	2.6	59.9	3.0	**65.6**	2.9	60.0	2.5	**65.4**
Inyo	1.2	32.1	0.2	**33.5**	1.9	32.0	0.2	**34.1**
Kern*	4.6	32.6	2.9	**40.1**	3.9	32.7	2.2	**38.9**
Kings	0.6	22.3	1.7	**24.5**	0.7	17.6	1.5	**19.8**
Madera	0.8	16.3	0.8	**18.0**	1.0	16.1	0.5	**17.6**
Merced	0.6	27.8	1.3	**29.6**	0.7	28.4	0.9	**29.9**
Mono	0.2	13.6	0.1	**13.9**	0.2	13.5	0.1	**13.8**
Monterey	2.0	26.2	1.2	**29.3**	2.2	26.4	1.0	**29.6**
San Benito	1.4	5.8	0.3	**7.4**	2.0	5.7	0.2	**7.8**
San Joaquin	2.0	25.3	2.4	**29.7**	2.3	25.6	1.9	**29.9**
San Luis Obispo	0.4	9.9	0.8	**11.1**	0.4	9.8	0.6	**10.8**
Santa Barbara	1.0	8.2	1.0	**10.2**	0.9	8.6	0.9	**10.3**
Santa Cruz	1.3	5.4	0.5	**7.2**	1.7	5.3	0.4	**7.4**
Stanislaus	1.6	24.5	1.4	**27.5**	1.8	25.8	1.1	**28.7**
Tulare	1.2	31.7	1.6	**34.5**	1.5	32.2	1.2	**34.9**
Ventura	0.6	13.9	2.0	**16.5**	0.7	15.8	1.8	**18.3**

**Portion of Kern County in San Joaquin Valley Air Basin*

Table E-20: Summary of ROG Emissions for Counties in the Air Basins in the Central California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alpine	0.0	0.2	0.4	**0.6**	0.0	0.2	0.3	**0.4**
Fresno	16.6	23.7	15.0	**55.4**	19.1	25.0	8.2	**52.2**
Inyo	0.1	1.8	1.6	**3.6**	0.1	1.6	0.9	**2.6**
Kern*	30.5	18.8	12.6	**62.0**	27.3	20.0	6.6	**53.9**
Kings	3.2	12.5	5.2	**21.0**	3.7	12.5	4.0	**20.2**
Madera	2.5	7.2	4.1	**13.8**	2.8	7.5	1.9	**12.2**
Merced	4.3	21.3	5.1	**30.8**	4.6	22.4	2.3	**29.4**
Mono	0.1	1.1	1.0	**2.2**	0.1	1.0	0.6	**1.8**
Monterey	6.6	15.3	8.4	**30.3**	6.1	14.2	4.4	**24.7**
San Benito	0.6	2.0	1.2	**3.8**	0.7	2.0	0.6	**3.2**
San Joaquin	9.2	14.2	13.7	**37.0**	9.9	15.3	7.0	**32.3**
San Luis Obispo	3.5	6.9	5.9	**16.3**	3.8	6.5	3.0	**13.3**
Santa Barbara	10.0	8.0	7.0	**25.0**	9.7	8.3	3.7	**21.8**
Santa Cruz	3.5	5.9	3.9	**13.2**	3.9	5.9	1.9	**11.7**
Stanislaus	8.3	18.9	7.3	**34.5**	8.3	19.5	3.9	**31.7**
Tulare	5.3	33.9	8.6	**47.7**	5.0	34.0	4.4	**43.4**
Ventura	8.6	11.3	12.6	**32.5**	8.6	11.4	7.0	**27.0**

**Portion of Kern County in San Joaquin Valley Air Basin*

Table E-21: Summary of SOx Emissions for Counties in the Air Basins in the Central California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Alpine	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**
Fresno	1.2	0.1	0.2	**1.4**	1.4	0.1	0.2	**1.7**
Inyo	0.5	0.0	0.0	**0.5**	0.6	0.0	0.0	**0.6**
Kern*	1.8	0.0	0.2	**2.0**	1.2	0.0	0.2	**1.4**
Kings	0.1	0.0	0.1	**0.2**	0.1	0.0	0.1	**0.2**
Madera	0.4	0.0	0.0	**0.4**	0.4	0.0	0.0	**0.5**
Merced	0.3	0.0	0.1	**0.3**	0.3	0.0	0.1	**0.4**
Mono	0.0	0.0	0.0	**0.1**	0.0	0.0	0.0	**0.1**
Monterey	0.7	0.1	0.1	**1.0**	0.8	0.1	0.1	**1.0**
San Benito	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**
San Joaquin	1.6	0.1	0.1	**1.7**	1.7	0.1	0.1	**1.8**
San Luis Obispo	0.5	0.0	0.0	**0.6**	0.5	0.0	0.0	**0.6**
Santa Barbara	0.7	0.0	0.1	**0.8**	0.6	0.0	0.1	**0.7**
Santa Cruz	0.1	0.1	0.0	**0.2**	0.1	0.1	0.0	**0.2**
Stanislaus	0.9	0.0	0.1	**1.0**	0.9	0.0	0.1	**1.0**
Tulare	0.3	0.1	0.1	**0.4**	0.3	0.1	0.1	**0.4**
Ventura	0.2	0.1	0.5	**0.8**	0.3	0.1	0.8	**1.1**

**Portion of Kern County in San Joaquin Valley Air Basin*

Table E-22: Summary of Ammonia Emissions for Counties in the Air Basins in the Southern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Imperial	1.6	41.4	0.2	**43.2**	1.6	42.2	0.2	**44.0**
Kern*	0.1	2.1	1.3	**3.5**	0.1	2.0	1.0	**3.1**
Los Angeles	16.3	22.4	10.2	**49.0**	16.8	22.7	6.8	**46.3**
Orange	9.5	4.9	3.3	**17.7**	9.6	5.3	2.3	**17.2**
Riverside	5.7	11.5	2.5	**19.8**	6.0	11.6	2.1	**19.7**
San Bernardino	5.8	15.3	2.7	**23.8**	5.9	13.0	2.1	**21.0**
San Diego	1.2	9.1	3.6	**13.9**	1.3	9.1	2.7	**13.1**

**Portion of Kern County in Mojave Desert Air Basin*

Table E-23: Summary of NOx Emissions for Counties in the Air Basins in the Southern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Imperial	1.8	0.6	17.0	**19.3**	1.6	1.0	12.3	**15.0**
Kern*	18.7	0.5	12.4	**31.7**	27.0	0.6	6.6	**34.2**
Los Angeles	36.4	13.0	233.6	**283.0**	31.1	8.7	114.4	**154.2**
Orange	5.4	4.0	58.1	**67.5**	5.3	2.7	24.1	**32.1**
Riverside	4.5	2.5	81.5	**88.4**	5.0	1.7	34.2	**41.0**
San Bernardino	33.3	2.9	117.7	**153.9**	45.4	2.3	54.9	**102.5**
San Diego	4.6	2.6	85.4	**92.6**	4.3	1.9	38.7	**44.9**

**Portion of Kern County in Mojave Desert Air Basin*

Table E-24: Summary of PM2.5 Emissions for Counties in the Air Basins in the Southern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Imperial	0.9	37.6	1.5	**40.0**	1.0	38.1	2.0	**41.1**
Kern*	0.8	2.5	3.1	**6.4**	1.0	2.5	3.0	**6.4**
Los Angeles	11.3	18.1	11.4	**40.8**	13.7	19.7	8.5	**41.9**
Orange	1.7	4.8	3.6	**10.0**	2.0	5.2	2.7	**9.9**
Riverside	1.1	8.1	3.7	**13.0**	1.6	10.3	2.6	**14.5**
San Bernardino	6.8	13.6	4.5	**24.9**	9.0	15.9	2.9	**27.8**
San Diego	2.6	10.7	6.0	**19.3**	2.9	10.9	4.7	**18.4**

**Portion of Kern County in Mojave Desert Air Basin*

Table E-25: Summary of PM10 Emissions for Counties in the Air Basins in the Southern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Imperial	3.6	284.8	1.8	**290.1**	3.8	280.1	2.4	**286.2**
Kern*	2.5	9.5	3.3	**15.3**	3.5	9.2	3.2	**15.9**
Los Angeles	21.4	56.7	19.6	**97.6**	28.2	65.8	16.7	**110.8**
Orange	2.5	14.5	6.4	**23.4**	3.0	16.3	5.6	**24.9**
Riverside	2.2	43.7	6.0	**51.9**	2.8	59.9	5.3	**67.9**
San Bernardino	12.3	75.5	7.1	**94.9**	16.0	87.9	5.8	**109.8**
San Diego	8.2	54.0	9.0	**71.3**	9.6	58.3	7.8	**75.8**

**Portion of Kern County in Mojave Desert Air Basin*

Table E-26: Summary of ROG Emissions for Counties in the Air Basins in the Southern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Imperial	1.4	11.7	6.6	**19.7**	1.3	12.6	5.1	**19.0**
Kern*	1.3	2.4	6.7	**10.4**	1.5	2.5	5.4	**9.3**
Los Angeles	58.7	74.8	125.2	**258.7**	63.5	79.9	65.1	**208.6**
Orange	17.0	22.5	44.3	**83.8**	19.3	23.9	25.3	**68.5**
Riverside	12.9	18.4	30.6	**61.9**	17.7	22.1	18.9	**58.7**
San Bernardino	14.0	20.4	38.9	**73.3**	15.9	22.3	19.6	**57.8**
San Diego	30.9	35.4	54.3	**120.7**	31.5	34.5	30.4	**96.4**

**Portion of Kern County in Mojave Desert Air Basin*

Table E-27: Summary of SOx Emissions for Counties in the Air Basins in the Southern California Region

	2014 Stationary	2014 Areawide	2014 Mobile	2014 Total	2028 Stationary	2028 Areawide	2028 Mobile	2028 Total
Imperial	0.0	0.1	0.2	**0.3**	0.0	0.2	0.1	**0.3**
Kern*	3.2	0.0	0.3	**3.6**	4.7	0.0	0.3	**5.0**
Los Angeles	8.8	0.4	3.8	**13.0**	9.4	0.4	4.6	**14.3**
Orange	0.3	0.1	0.5	**1.0**	0.4	0.1	0.5	**1.0**
Riverside	0.4	0.1	0.4	**0.8**	0.4	0.1	0.4	**0.9**
San Bernardino	1.8	0.1	0.6	**2.4**	2.3	0.1	0.7	**3.2**
San Diego	0.3	0.1	0.7	**1.1**	0.3	0.1	0.6	**1.1**

**Portion of Kern County in Mojave Desert Air Basin*

F. Modeling Scenarios References

Regional photochemical modeling to support development of this Regional Haze Plan was conducted by the Western Regional Air Partnership (WRAP). Weblinks to specific reference documents prepared by the WRAP and its contractors are available listed below.

Specification sheets for each of the WRAP's regional haze modeling scenarios and reference information for model inputs are available online through the Intermountain West Data Warehouse.[53]

The modeling reference document with detailed specifications is archived on the WRAP's website.[54]

A description of the modeling platform and the performance evaluation for the western region is archived on the website for the Intermountain West Data Warehouse.[55]

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[53] *https://views.cira.colostate.edu/iwdw/docs/WAQS_and_WRAP_Regional_Haze_spec_sheets.aspx*

[54] *http://views.cira.colostate.edu/tssv2/Docs/WRAP_TSS_modeling_reference_final_20210930.pdf*

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

USFS Alternative Endpoint Adjustment Methods

A description of methodology used by U.S. Forest Service (USFS) to calculate alternative prescribed fire adjustments to the 2064 endpoints follows. The text and figures that follow were prepared by USFS staff and are included here for reference.

Future fire sensitivities added wildfire emissions (FFS1) or wildland prescribed fire emissions (FFS2) as two potential future variations in fire activity that are not specific to any single future year. The fire sensitivities are added to the 2028OTBa2 reference case scenario to replace historic fire emissions originally used in the 2028OTBa2 scenario while keeping constant all other U.S. anthropogenic, international, natural, and non-US fire emissions. The only differences between the 2028OTBa2 and the fire sensitivities are due to the FFS1 and FFS2 assumptions. Emissions development of the future fire sensitivities is described in the Air Sciences, Inc. report *Fire Emissions Inventories for Regional Haze Planning: Methods and Results* (April 2020). Modeling methods are defined in *WRAP Future Fire Sensitivity Simulations* (August 2021).

Theoretically, since the only differences between 2028OTBa2 and the FFS2 are the assumptions due to the increased acres treated in FFS2, one should be able to isolate the change in extinction on the most impaired days (MID) by calculating the incremental difference FFS2 and 2028OTBa2 by subtracting the 2028OTBa2 results from the FFS2 results.

Procedures

1. Get "Default" Rx fire adjustment from Product #5, WRAP TSS, Model Express Tools ("Adjustment Options for End of URP Glidepath")

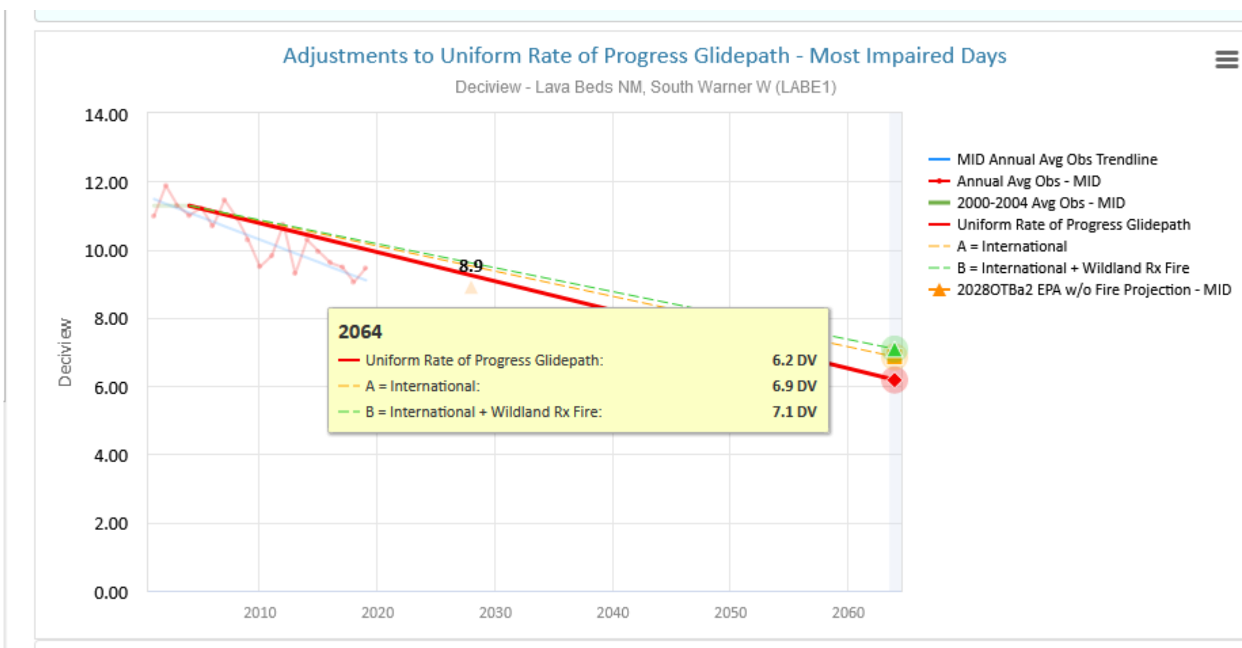

Figure 1- Example WRAP TSS Product #5, Model Express Tools

2. Subtract "End Point A – International" from "End Point B – International + Wildland Rx Fire"
    a. Example: Lava Beds NM, CA: B = 7.1 DV, A = 6.9 DV. Rx fire component of adjustment = B – A or 7.1 – 6.9, which yields 0.2 DV different or "default endpoint adjustment for Wildland Rx fire.
3. Convert Wildland Rx Fire DV to extinction units (Mm^{-1})
    a. Obtain 2064 unadjusted end point in DV from Product #5, WRAP TSS (see figure 1 above, URP Glidepath)
        i. Example: Lava Beds NM, CA: end of the URP in 2064 = 6.2 DV
    b. Add Wildland Rx Fire DV from Step 2 to Unadjusted 2064 end point from Step 1 and Subtract 2064 URP end point (unadjusted) to calculate Wildland Rx Fire contribution in extinction units by following formula: $10*EXP((2064_{DV}+RxFire_{DV})/10)-10*EXP(2064_{DV}/10)$.
        i. Example: Lava Beds NM, CA: 10*EXP((6.2 + 0.2)/10 – 10*EXP(6.2/10) = 0.375528 Mm^{-1}
4. To calculate incremental contribution from WRAP Future Fire Scenario 2 (Increased Wildland Rx Fire ("FFS2")), obtain extinction results for 2028 OTBa2 scenario AND 2028 FFS2 scenario from WRAP TSS, Model Express tools, Product #18 ("Future Fire Sensitivities Visibility Projections – Most Impaired Days")
    a.
        i. 2028 OTBa2 results: stacked bar chart, column 2 = 16.31 Mm^{-1} (Figure 2, "A")
        ii. 2028 FFS2 results: stacked bar chart, column 4 = 16.53 Mm^{-1} (Figure 2, "B")
    b. Add Rayleigh scatter back to each value from steps 4.a.i and 4.a.ii
        i. Example: Lava Beds NM, CA: Rayleigh = 10, so add Rayleigh back to 2028 OTBa2 and 2028 FFS2
            1. 2028 OTBa2 = 16.31; Rayleigh = 10; Total Bext = 26.31 Mm^{-1}
            2. 2028 FFS2 = 16.54; Rayleigh = 10; Total Bext = 26.53 Mm^{-1}
    c. Subtract total extinction, 2028 OTBa2 from total extinction, 2028 FFS2
        i. Example: Lava Beds NM, CA: 26.53Mm^{-1} (2028_{FFS2} Bext) – 26.31 Mm^{-1} (Bext 2028_{OTBa2}) = 0.22 Mm^{-1} ($Bext_{\Delta 2028FFS2}$)
    d. Difference from 4.c.i will yield the incremental increase of 2028_{FFS2} above 2028_{OTBa2} in extinction units (Mm^{-1}).
    e. Convert the 2064 URP unadjusted endpoint into extinction units (Mm-1)
        i. Example: Lava Beds NM, CA: $Bext_{2064URP} = 10*EXP(DV_{2064URP}/10)$, or 10*EXP(6.2/10)
    f. To calculate the "alternative glideslope adjustment" (which reflects the land management policy change of increasing acres treated with prescribed fire = Total ∆Wildland Rx Fire which is the sum of 2028OTBa2 and FFS2 prescribed fire impacts in Mm^{-1}), add the incremental change in extinction units from 2028_{FFS2} (step 4.c.i) to the original projection from 2028_{OTBa2} in extinction units (step 3.b) and convert to deciview units by the following equation: $10*LN(((Bext_{\Delta 2028FFS2}(Mm-1) + Bext_{2028OTBa2}) + Bext_{2064URP})/10) – DV_{2064URP}$

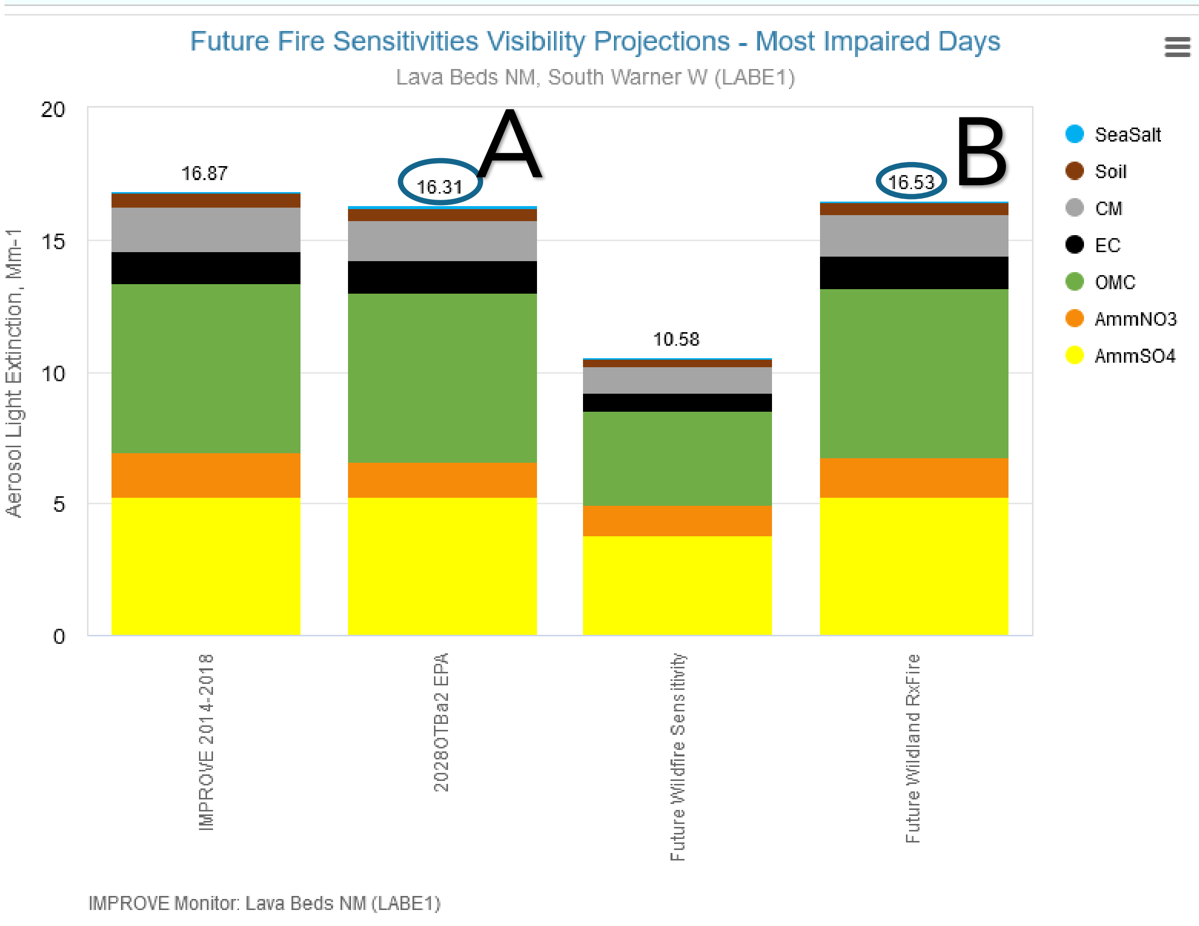

Figure 2- Future Fire Sensitivities Total Extinction - Most Impaired Days

G. Stationary Source Screening

Stationary Source Screening Steps

Step 1: Calculate NOx Q/d as a Surrogate for Visibility Impacts

Stationary sources with a NOx Q/d greater than five were selected in this analysis as potentially impacting California Class 1 areas. Q represents annual NOx emissions reported in tons per year (tpy) to the National Emissions Inventory (NEI) and d represents the distance between the stationary source and a Class I area (measured in km from the source to the nearest boundary of the Class I area).

Forty-two stationary sources were identified in this first screening step. These sources included petroleum refining facilities, airports, cement plants, and biomass energy or cogeneration facilities, steel mills, a paper plant, a generating station, and a mineral extraction facility. These sources were in the jurisdictions of ten local air districts. The stationary sources selected for screening are listed in Table G-1, which is organized by local air district and then facility name in alphabetical order.

Step 2: Review Device Level Emission Inventories

Device level inventories were reviewed for each of the stationary sources on the initial screening list and local air district staff were consulted to confirm actual emissions and operating status. Stationary sources were excluded if actual emissions or emissions under State or local jurisdiction led to a Q/d less than five.

Seventeen stationary sources, including twelve airports, were excluded from further consideration at this screening step. A description of the sources excluded from further consideration at this step are detailed in the discussion that follows Table G-1.

Step 3: Review Existing Controls, Planned Controls, and Proposed Operational Changes

For each of the remaining stationary sources, operating permits were reviewed as well as plans for additional emission controls or proposed operational changes. Facilities were excluded at this step if the information about existing controls, planned controls, or planned operational changes indicated that a full four factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, reasonable controls are in place and no further reasonable controls are necessary at this time.

Twenty-four stationary sources were excluded from further consideration at this screening step. A description of the sources excluded from further consideration at this step are detailed in the discussion that follows Table G-1.

A full four factor analysis was completed for the remaining source. A description of that analysis is provided in Appendix H.

Table G-1: Stationary Sources in California with a 2017 NOx Q/d > 5.0

Facility Name	Local Air District	Location with Maximum Q/d	Distance (km)	NEI (tpy)	Q/d
Chevron Products Company	Bay Area AQMD	Point Reyes National Seashore	28	737	26.4
Lehigh Southwest Cement Company	Bay Area AQMD	Point Reyes National Seashore	86	1208	14.0
Oakland Metropolitan International Airport	Bay Area AQMD	Point Reyes National Seashore	50	1262	25.4
Phillips 66 Carbon Plant	Bay Area AQMD	Point Reyes National Seashore	43	360	8.5
Phillips 66 Company - San Francisco Refinery	Bay Area AQMD	Point Reyes National Seashore	43	218	5.1
San Francisco International Airport	Bay Area AQMD	Point Reyes National Seashore	45	5105	113.4
San Jose Airport - Norman Y Mineta	Bay Area AQMD	Point Reyes National Seashore	92	884	9.6
Shell Martinez Refinery (now owned by PBF)	Bay Area AQMD	Point Reyes National Seashore	53	916	17.2
Tesoro Refining & Marketing Company Llc	Bay Area AQMD	Point Reyes National Seashore	57	360	6.3
Valero Refining Company	Bay Area AQMD	Point Reyes National Seashore	52	1013	19.3
CalPortland Cement - Mojave Plant	Eastern Kern APCD	Domeland Wilderness Area	75	1531	20.5
Granite Construction - Lee Vining	Great Basin Unified APCD	Ansel Adams Wilderness Area	6	31	5.2
Kirkwood Powerhouse	Great Basin Unified APCD	Mokelumne Wilderness Area	1	10	16.6
Cal Portland Oro Grande (formerly Riverside)	Mojave Desert AQMD	Cucamonga Wilderness Area	41	1141	27.9
Cemex - Black Mountain Quarry	Mojave Desert AQMD	San Gorgonio Wilderness Area	53	5420	101.6
Mitsubishi Cement	Mojave Desert AQMD	San Gorgonio Wilderness Area	33	1944	59.7
Searles Valley Mineral	Mojave Desert AQMD	Domeland Wilderness Area	71	1517	21.3
Arcata	North Coast Unified AQMD	Redwood National Park	17	163	9.7
Collins Pine Co	Northern Sierra AQMD	Caribou Wilderness Area	12	129	10.4
Sierra Pacific Industries - Quincy	Northern Sierra AQMD	Caribou Wilderness Area	59	392	6.6
Sacramento International Airport	Sacramento Metro AQMD	Desolation Wilderness Area	117	737	6.3

Facility Name	Local Air District	Location with Maximum Q/d	Distance (km)	NEI (tpy)	Q/d
San Diego International-Lindberg	San Diego County APCD	Agua Tibia Wilderness Area	74	1580	21.3
Burney Forest Products	Shasta County AQMD	Thousand Lakes Wilderness Area	17	190	11.2
Lehigh Southwest Cement Company	Shasta County AQMD	Thousand Lakes Wilderness Area	56	603	10.7
Sierra Pacific Industries - Burney	Shasta County AQMD	Thousand Lakes Wilderness Area	18	157	8.9
Wheelabrator Shasta E.C.I.	Shasta County AQMD	Yolla Bolly-Middle Eel Wilderness Area	57	536	9.4
Bob Hope Airport	South Coast AQMD	San Gabriel Wilderness Area	31	375	12.0
California Steel Industries Inc.	South Coast AQMD	Cucamonga Wilderness Area	16	125	7.8
Chevron Products Co.	South Coast AQMD	San Gabriel Wilderness Area	52	729	14.0
Desert View Power	South Coast AQMD	Joshua Tree National Park	24	189	7.8
John Wayne Airport	South Coast AQMD	Cucamonga Wilderness Area	62	698	11.3
Long Beach Daugherty Field Airport	South Coast AQMD	San Gabriel Wilderness Area	49	308	6.3
Los Angeles International Airport	South Coast AQMD	San Gabriel Wilderness Area	49	7836	159.0
New- Indy Ontario, Llc	South Coast AQMD	Cucamonga Wilderness Area	18	137	7.5
Ontario International Airport	South Coast AQMD	Cucamonga Wilderness Area	17	679	40.2
Palm Springs International Airport	South Coast AQMD	San Jacinto Wilderness Area	10	159	16.4
Phillips 66 Co/La Refinery Wilmington Pl	South Coast AQMD	San Gabriel Wilderness Area	58	471	8.1
Phillips 66 Company/Los Angeles Refinery	South Coast AQMD	San Gabriel Wilderness Area	53	391	7.3
Tamco	South Coast AQMD	Cucamonga Wilderness Area	13	108	8.3
Tesoro Refining & Marketing (Carson)	South Coast AQMD	San Gabriel Wilderness Area	51	661	13.0
Tesoro Refining and Marketing (Wilmington)	South Coast AQMD	San Gabriel Wilderness Area	54	749	13.8
Torrance Refining (formerly Exxon Mobil)	South Coast AQMD	San Gabriel Wilderness Area	52	924	17.6

Discussion of Sources Excluded from Consideration at Screening Step 2

Bay Area AQMD

The Bay Area AQMD was established in 1955 as the first regional air pollution control agency in the country. The agency regulates stationary sources in nine counties: Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, the western portion of Solano, and the southern portion of Sonoma. The San Francisco Bay Area, which includes the entirety of the Bay Area AQMD's nine country jurisdiction, is designated as nonattainment for the ozone and PM2.5 National Ambient Air Quality Standards (NAAQS) listed below.

- Marginal Nonattainment for 2008 and 2015 Ozone NAAQS
- Moderate Nonattainment for 2006 PM2.5 NAAQS

Four stationary sources in the jurisdiction of the Bay Area AQMD were excluded from further consideration at the second screening step. A discussion of each of these stationary sources follows.

Norman Y Mineta San Jose International Airport
Facility ID: 9993811
Nearest Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 884 tpy
2017 NOx Q/d: 9.6

The Norman Y Mineta Airport is a public airport in Santa Clara County that covers 1,050 acres. In 2019, total aircraft operations included 205,886 flights.[56] NEI data indicate that ninety-five percent of NOx emissions are from aircraft. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this stationary source will be excluded from further consideration.

Oakland Metropolitan Airport
Facility ID: 10522811
Nearest Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 1262 tpy
2017 NOx Q/d: 25.4

The Oakland Metropolitan Airport is a public airport in Alameda County that covers 2,600 acres. In 2019, total aircraft operations included 242,757 flights.[57] NEI data indicate that ninety-six percent of NOx emissions were from aircraft. State and local agencies do not

[56] https://adip.faa.gov/agis/public/#/airportData/SJC
[57] https://adip.faa.gov/agis/public/#/airportData/OAK

have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

San Francisco International Airport
Facility ID: 9997011
Nearest Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 5,105 tpy
2017 NOx Q/d: 113.4

The San Francisco International Airport is a public airport in San Mateo County that covers 5,207 acres. In 2019, total aircraft operations included 458,502 flights.[58] NEI data indicate that ninety-six percent of NOx emissions are from aircraft. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

Tesoro Refining & Marketing Company
Facility ID: 6480811
Nearest Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 360 tpy
2017 NOx Q/d: 6.3

The Tesoro Refinery & Marketing Company in Martinez was sold to Marathon in 2018. In April 2020, Marathon suspended operations. In August 2020, Marathon indefinitely idled the refinery. In February 2021, the company submitted a CEQA Notice of Preparation (NOP) requesting approval of a project proposal to convert the refinery to a renewable fuels facility. The conversion would include modifications to existing processing units, installation of new equipment including an advanced three-stage low-NOx thermal oxidizer, and removal of obsolete units including a crude unit, hydrotreater, reformers, delayed cokers, steam boilers, and the fluidized catalytic cracking unit. At completion of the project, the facility would have the capacity to process 48,000 barrels per day. The estimated time to complete the project is approximately two years, with full production projected by the end of 2023.

The NOP and associated documents for the Martinez Refinery Renewable Fuels Project are available online.[59]

This stationary source is not currently operating. The proposed project will trigger a permit modification. When it resumes operation, it will be subject to AB 617 and will be required to

[58] https://adip.faa.gov/agis/public/#/airportData/SFO

[59] https://www.contracosta.ca.gov/7961/Martinez-Refinery-Renewable-Fuels-Projec

have best available retrofit control technology (BARCT) level controls in place for control of NOx emissions. A full four factor analysis is not be feasible considering the current shutdown and pending modification. Emission controls at this stationary source will be considered during the next progress report to ensure that, for the purposes of the regional haze program, reasonable controls are in place.

Great Basin Unified APCD

The Great Basin Unified APCD was established in 1974. The district regulates stationary sources in three counties that make up the Great Basin Valleys Air Basin: Alpine, Inyo, and Mono. Mono County and the Owens Valley portion of Inyo County are designated as nonattainment for the PM10 NAAQS.

- Moderate Nonattainment for 1987 PM10 NAAQS (Mono County)
- Serious Nonattainment for 1987 PM10 NAAQS (Owens Valley, Inyo County)

Two stationary sources in the jurisdiction of the Great Basin Unified APCD were excluded from further consideration at the second screening step. A discussion of these sources follows.

Granite Construction – Lee Vining
Facility ID: 6649111
Nearest Class I Area: Ansel Adams Wilderness Area
2017 NEI NOx Emissions: 31 tpy
2017 NOx Q/d: 5.2

Granite Construction operates a materials plant in Lee Vining, on the eastern side of the Sierra Nevada Mountain Range. Per district staff, actual NOx emissions from this source in 2017 were 0.5 tpy and were consistent with emission from a typical operating year. Considering annual emissions of 0.5 tpy results in a revised Q/d that is less than one. Based on this information, this stationary source will be excluded from further consideration.

Kirkwood Powerhouse
Facility ID: 13839511
Nearest Class I Area: Mokelumne Wilderness Area
2017 NEI NOx Emissions: 10 tpy
2017 NOx Q/d: 16.6

The Kirkwood Powerhouse is operated by Kirkwood Meadows Public Utilities District and supplies power to the local community. All NOx emissions are from eight generator engines. In 2014, Kirkwood Meadows Public Utilities District transitioned to line power and all the generators were transitioned from prime to emergency back-up engines. Per district staff, SCR was installed on the emergency back-up generators when permits were issued in 2015. The district engineering evaluation at that time determined that SCR was BACT. Following the transition to line power, actual NOx emissions are less than 0.1 tpy from this facility, which results in a Q/d that is less than one. Based on this information, this stationary source will be excluded from further consideration.

North Coast Unified AQMD

The North Coast Unified AQMD is responsible for regulating stationary sources in the counties of Del Norte, Humboldt, and Trinity. All areas under the jurisdiction of the Norther Coast Unified AQMD are designated as attainment or unclassified for all NAAQS.

One stationary source in the jurisdiction of the North Coast Unified AQMD was excluded from further consideration at the second screening step. A discussion of that source follows.

Arcata
Facility ID: 10414711
Nearest Class I Area: Redwood National Park
2017 NEI NOx Emissions: 169 tpy
2017 NOx Q/d: 9.7

Arcata is a regional airport, also known as the California Redwood Coast-Humboldt County Airport as well as the Arcata-Eureka Airport. It is a public airport that covers 745 acres. In 2019, total operations included approximately 42,000 flights, with military operations accounting for more than sixty percent of total annual flights.[60] NEI data indicate that ninety-nine percent of NOx emissions are from aircraft emissions. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

Sacramento Metropolitan AQMD

The Sacramento Metropolitan AQMD regulates stationary sources in Sacramento County. Sacramento County is part of the Sacramento Metro area that is designated as nonattainment for the ozone and PM2.5 NAAQS listed below.

- Moderate Nonattainment for 2015 Ozone NAAQS
- Severe Nonattainment for 2008 Ozone NAAQS
- Moderate Nonattainment for 2006 PM2.5 NAAQS

One stationary source in the jurisdiction of the Sacramento Metropolitan AQMD was excluded from further consideration at the second screening step. A discussion of that source follows.

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[60] *https://adip.faa.gov/agis/public/#/airportData/ACV*

Sacramento International Airport
Facility ID: 10093011
Nearest Mandatory Federal Class I Area: Desolation Wilderness Area
2017 NEI NOx Emissions: 737 tpy
2017 NOx Q/d: 6.3

The Sacramento International Airport is a public airport that covers 6,000 acres. In 2019, total aircraft operations included 124,512 flights.[61] NEI data indicate that ninety-five percent of NOx emissions are from aircraft emissions. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

San Diego County APCD

The San Diego County APCD is responsible for the regulation of stationary sources in San Diego County. San Diego County is designated as nonattainment for the ozone NAAQS.

- Severe Nonattainment for 2008 and 2015 Ozone NAAQS

One stationary source in the jurisdiction of the San Diego County APCD was excluded from further consideration at the second screening step. A discussion of that source follows.

San Diego International Airport – Lindberg Field
Facility ID: 10086111
Nearest Class I Area: Agua Tibia Wilderness Area
2017 NEI NOx Emissions: 1580 tpy
2017 NOx Q/d: 21.3

San Diego International Airport is a public airport that covers 663 acres. In 2019, total aircraft operations included 231,354 flights.[62] NEI data indicate that ninety-six percent of NOx emissions are from aircraft emissions. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

South Coast AQMD

The South Coast AQMD was formed in 1976 and is responsible for regulating stationary sources in an area that spans four counties and includes Los Angeles County, except for the northeast portion covered by the Antelope Valley AQMD, Orange County, and the western portions of San Bernardino and Riverside counties. The jurisdiction of the South Coast AQMD

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[61] https://adip.faa.gov/agis/public/#/airportData/SMF
[62] https://adip.faa.gov/agis/public/#/airportData/SAN

includes the South Coast Air Basin and the Coachella Valley, areas that are designated as nonattainment for the NAAQS listed below.

- Extreme Nonattainment for the 2008 and 2015 Ozone NAAQS (South Coast Air Basin)
- Severe Nonattainment for the 2008 and 2015 Ozone NAAQS (Coachella Valley)
- Serious Nonattainment for the 2006 and 2012 PM2.5 NAAQS (South Coast Air Basin)
- Serious Nonattainment for the 1987 PM10 NAAQS (Coachella Valley)
- Nonattainment for the 2008 Lead NAAQS (portion of Los Angeles County in the South Coast Air Basin)

Eight stationary sources in the jurisdiction of the South Coast AQMD were excluded from further consideration at the second screening step. A discussion of these sources follows.

Bob Hope Airport
Facility ID: 2255611
Nearest Class I Area: San Gabriel Wilderness Area
2017 NEI NOx Emissions: 375 tpy
2017 NOx Q/d: 12.0

Bob Hope Airport is a public airport in Los Angeles County 555 acres. In 219, total aircraft operations included 146,440 flights.[63] NEI data indicate that ninety-five percent of NOx emissions are from aircraft emissions during landing and take-off. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

Desert View Power
Facility ID: 15776111
Nearest Mandatory Federal Class I Area: Joshua Tree National Park
2017 NEI NOx Emissions: 189 tpy
2017 NOx Q/d: 7.8

Desert View Power is a 47 MW biomass power plant producing electrical power that it currently supplies under a long-term contract exclusively to the Imperial Irrigation District. NOx emissions come from two wood-fired boilers. NOx emissions from the boiler are controlled by ammonia injection. The facility is required to tune-up boilers every five years. The facility is located on Cabazon Indian Reservation land and is permitted by the U.S. EPA. The U.S. EPA has a Monitoring and Enforcement Agreement with South Coast AQMD, but the applicability of local rules and regulations are limited to those detailed in the Agreement.

[63] *https://adip.faa.gov/agis/public/#/airportData/BUR*

Based on this information, the facility will be excluded from further consideration because operations are permitted by U.S. EPA, not state or local agencies.

John Wayne Airport
Facility ID: 496011
Nearest Mandatory Federal Class I Area: Cucamonga Wilderness Area
2017 NEI NOx Emissions: 698 tpy
2017 NOx Q/d: 11.3

John Wayne Airport is a public airport in Orange County that covers 504 acres. In 2019, total aircraft operations included 318,485 flights.[64] NEI data indicate that ninety-six percent of NOx emissions are from aircraft emissions. When emissions from aircraft are excluded, the Q/d is less than one. State and local agencies do not have authority to set emissions limits for aircraft. Based on this information, this facility will be excluded from further consideration.

Long Beach Daugherty Field
Facility ID: 2255711
Nearest Mandatory Federal Class I Area: San Gabriel Wilderness Area
2017 NEI NOx Emissions: 308 tpy
2017 NOx Q/d: 6.3

Long Beach Daugherty Field is a public airport in Los Angeles County that covers 1,166 acres. In 2019, total aircraft operations included 304,357 flights.[65] NEI data indicate that ninety-six percent of NOx emissions are from aircraft emissions. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than 1. Based on this information, this facility will be excluded from further consideration.

Los Angeles International Airport
Facility ID: 2255111
Nearest Mandatory Federal Class I Area: San Gabriel Wilderness Area
2017 NEI NOx Emissions: 7,836 tpy
2017 NOx Q/d: 159

Los Angeles International Airport is a public airport in Los Angeles County that covers 3,500 acres. In 2019, total aircraft operations included 691,257 flights.[66] Ninety-seven percent of NOx emissions are from aircraft emissions during landing and take-off. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from

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[64] *https://adip.faa.gov/agis/public/#/airportData/SNA*

[65] *https://adip.faa.gov/agis/public/#/airportData/LGB*

[66] *https://adip.faa.gov/agis/public/#/airportData/LAX*

aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

Ontario International Airport
Facility ID: 3361511
Nearest Mandatory Federal Class I Area: Cucamonga Wilderness Area
2017 NEI NOx Emissions: 679 tpy
2017 NOx Q/d: 40.2

Ontario International Airport is a public airport in San Bernardino County that covers 1,741 acres. In 2019, total aircraft operations included 101,135 flights.[67] NEI data indicated that ninety-six percent of NOx emissions are from aircraft emissions. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

Palm Springs International Airport
Facility ID: 2540911
Nearest Mandatory Federal Class I Area: San Jacinto Wilderness Area
2017 NEI NOx Emissions: 159 tpy
2017 NOx Q/d: 16.4

Palm Springs International Airport is a public airport in Riverside County that covers 940 acres. In 2019, total aircraft operations included 58,706 flights.[68] NEI data indicate that ninety-five percent of NOx emissions are from aircraft emissions. State and local agencies do not have authority to set emissions limits for aircraft. When emissions from aircraft are excluded, the Q/d is less than one. Based on this information, this facility will be excluded from further consideration.

Tamco
Facility ID: 4840211
Nearest Mandatory Federal Class I Area: Cucamonga Wilderness Area
2017 NEI NOx Emissions: 108 tpy
2017 NOx Q/d: 8.3

The facility will be excluded from further consideration because it was permanently shut down in January 2021.

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[67] *https://adip.faa.gov/agis/public/#/airportData/ONT*
[68] *https://adip.faa.gov/agis/public/#/airportData/PSP*

Discussion of Sources Excluded from Consideration at Screening Step 3

Bay Area AQMD

Six stationary sources excluded from further consideration at the third step in the screening process are in the jurisdiction of the Bay Area AQMD. The sources include five petroleum processing facilities and one cement facility. All six of these facilities are subject to the expedited BARCT requirements of California's AB 617. As part of their efforts to comply with AB 617, the Bay Area AQMD reviewed local rules and is in the process of adopting rule revisions. The district has determined that several rules that apply to facilities subject to the expedited BARCT requirement of AB 617 already meet BARCT stringency, including those listed below that apply to facilities on the initial screening list.

- Regulation 9, Rule 6: NOx Emissions from Natural Gas-Fired Boilers and Water Heaters
- Regulation 9, Rule 7: NOx and CO from Industrial, Institutional, And Commercial Boilers, Steam Generators, And Process Heaters
- Regulation 9, Rule 8: NOx and CO from Stationary Internal Combustion Engines
- Regulation 9, Rule 9: NOx and CO from Stationary Gas Turbines
- Regulation 9, Rule 10: NOx and CO from Boilers, Steam Generators And Process Heaters In Petroleum Refineries
- Regulation 9, Rule 13: NOx, PM, and TACs from Portland Cement Manufacturing
- Regulation 9, Rule 14: Petroleum Coke Calcining Operations

The rule revision that will likely impact NOx emissions from the facilities on the screening list is Regulation 6, Rule 5: PM from Refinery Fluidized Catalytic Cracking Units. A discussion of the six sources in the Bay Area AQMD jurisdiction that were excluded for further consideration at the third step in the screening process follows.

Chevron Products Company
Facility ID: 6530111
Nearest Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 737 tpy
2017 NOx Q/d: 26.4

Chevron Products Company operates a petroleum refinery in Richmond that processes crude oil into various fuel and petroleum products. Refinery operations began at the Richmond location in 1902, under the ownership of Pacific Coast Oil Company, to process crude oil extracted from southern California oil fields. Currently, the refinery is permitted to process 257,200 barrels of crude oil per day. The refinery produces about 65 percent of jet fuel for Bay Area airports, 20 percent of Bay Area gasoline, and is the only lubricant base oil producer on the west coast. The facility is subject to the expedited BARCT requirements of California's AB 617 and a 2005 U.S. EPA Consent Decree.

The largest NOx emission sources at the refinery are the fluidized catalytic cracking units (FCCU), process heaters, and cogeneration turbines. Emissions from the FCCU can be controlled through hydrotreating the feed, the use of catalysts to remove impurities, improved catalyst regeneration or installation of a scrubber. The FCCU at Chevron will be subject to the revisions in Regulation 6, Rule 5 that were recently adopted by the Bay Area AQMD in response to AB 617 expedited BARCT requirements. While the rule will specifically target emissions of condensable particulate matter, NOx contributes to condensable particulate matter in the exhaust stream. The facility will be required to meet emission limits required by the rule revision by the end of 2023.

The Bay Area AQMD considered two scenarios to control FCCU emissions, which are summarized in Table G-2. The scenario in the revision adopted by the district's governing board will require the installation of a wet gas scrubber to meet particulate matter emission limits from the FCCU. The basis used to determine costs are available from the BAAQMD.[69]

Table G-2: Cost effectiveness of control measures for Chevron considered in revision of BAAQMD Regulation 6 Rule 5

FCCU Control Options Considered	PM10 Reductions	Capital Cost	Total Annualized Cost	Cost Effectiveness
Expand existing controls to include ESP, feed hydrotreatment, and a catalyst additive	80 tpy	$30 million	$4.4 million/year	$55,300/ton
Install wet gas scrubber	160 tpy	$241 million	$39 million/year	$242,700/ton

Combustion unit emissions are controlled through the use of burner technology, steam injection, or SCR units. Multiple furnaces have SCR units and permit limits of 40 ppm NOx at 3% O_2 (8h average). Cogeneration turbines have SCR units and emission limits of <10 ppm at 15% O_2 (3h average) while operating except for startup/shutdown as well as 0.20 lb/MMBtu as a 30-day rolling average.

The 2005 U.S. EPA consent decree required the subject FCCU and the subject heaters/boilers to meet a 365-day rolling average NOx emission limit of 20 ppmv at 0% O_2 and 0.020 lbs/MMBtu, respectively. In addition to the 365-day rolling average, the FCCU also was required to meet a seven-day rolling average of 40 ppmv at 0% O_2 and the heaters and boilers were required to meet a facility average of 0.040 lbs/MMBtu with qualifying controls installed on equipment representing at least 30% of the facility's heat capacity.

[69] https://www.baaqmd.gov/rules-and-compliance/rules/reg-6-rule-5-particulate-emissions-from-refinery-fluidized-catalytic-cracking-units

The facility's current operating permit includes the federal interim refinery-wide emissions limit (excluding CO boilers) of 0.20 lbs NOx/MMBtu as well as the more stringent refinery-wide emissions limit (excluding CO boilers) of 0.033 lbs NOx/MMBtu.

Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further reasonable controls are necessary at this time.

Lehigh Southwest Cement Company
Facility ID: 7066411
Nearest Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 1,208 tpy
2017 NOx Q/d: 14.0

The Lehigh Southwest Cement Company operates a limestone quarry, mill, and Portland cement manufacturing facility in Cupertino. Quarry operations began in the early 1900s and the first use permit for the cement plant was issued in 1939, and later modified in the 1950s to add rotary kilns. The facility's initial Title V permit was issued in 2003. The facility is subject to the expedited BARCT requirements of AB 617 and a 2019 U.S. EPA consent decree.

Ninety-eight percent of NOx emissions are from the kiln. In 2015, 32 kiln stacks and two fuel mill stacks were combined into a single stack. NOx emissions from the single stack are controlled by a SNCR system with ammonia injection. The 2019 U.S. EPA consent decree set NOx emission limits for the kiln at 2.0 lbs/ton of clinker and required the facility to comply with these limits within 12 months of the effective date.

Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further reasonable controls are necessary.

Phillips 66 Carbon Plant
Facility ID: 5812811
Nearest Mandatory Federal Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 360 tpy
2017 NOx Q/d: 8.5

Phillips 66 operates a calcined petroleum coke plant in Rodeo. The facility is subject to the expedited BARCT requirements of AB 617. NOx emissions are from two 62 MMBtu/hr natural gas-fired calcining kilns. Emissions from the kilns are controlled by a pyroscrubber. Calcined coke throughput is limited to 262,800 tons per year by the Title V permit.

In December 2020, Phillips 66 filed a CEQA NOP requesting approval to implement the Rodeo Renewed Project. The scope of the project includes decommissioning and potential demolition of the Carbon Plant as well as surrendering the existing air permits. Project documents are available online.[70]

Based on this information, this facility will be excluded from further consideration at this time due to the pending project proposal and relatively short time frame in the proposal for decommissioning the facility. Emission controls at this facility will be considered during the next progress report to ensure that decommissioning of the facility has occurred or that, for the purposes of regional haze, reasonable controls are in place.

Phillips 66 San Francisco Refinery
Facility ID: 15733011
Nearest Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 218 tpy
2017 NOx Q/d: 5.1

Phillips 66 operates a petroleum refinery, known as the San Francisco Refinery, in Rodeo. The facility was initially constructed in 1896 and covers an area of 1,100 acres. The San Francisco Refinery in Rodeo is linked by a 200-mile pipeline to the Santa Maria Refinery, on the central coast of California. The inter-facility pipeline transports semi-refined products from Santa Maria to San Francisco for finishing. The Rodeo facility has a total throughput capacity of 140,000 barrels per day. The facility is subject to the expedited BARCT requirements of AB 617.

The main NOx emission sources are process heaters and three 16.6 MW process gas combustion turbines. NOx emissions from the individual process heaters range from less than one ton per year to 18 tons per year. Process heaters are subject to the facility-wide NOx emissions limit of 0.033 lbs/MMBtu of heat input (operating day average). Several process heaters have selective catalytic reduction (SCR) systems installed. NOx emissions from the combustion turbines are controlled by an SCR system. The NOx emission limits in the Title V permit are 66 lbs/hr and 9 ppmv at 15% O_2.

In December 2020, Phillips 66 filed a CEQA NOP requesting approval for the Rodeo Renewed Project that will affect operations at the San Francisco Refinery and the Carbon Plant. The scope of the project includes transforming the existing refinery into a facility that would process renewable feedstocks into renewable diesel fuel, renewable components of other transportation fuels, and renewable fuel gas. The facility would produce approximately 55,000 barrels per day of renewable transportation fuels and 12,000 barrels per day of blended fuels. Upon completion of the proposed project, the refinery would no longer process crude oil and petroleum feedstocks into transportation fuels. Renewable feedstocks would be delivered via the existing marine terminal. The facility would surrender their

[70] https://www.contracosta.ca.gov/7945/Phillips-66-Rodeo-Renewed-Project

existing air permits. The project is expected to take 24 months to complete. The complete NOP is available online.[71]

Based on this information, this facility will be excluded from further consideration at this time due to the pending project proposal and relatively short time frame in the proposal for reconfiguring the facility and surrender of the existing air permits. Emission controls at this facility will be considered during the next progress report to ensure that, for the purposes of regional haze, reasonable controls are in place.

Shell Martinez Refinery
Facility ID: 6531011
Nearest Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 916 tpy
2017 NOx Q/d: 17.2

The Shell Martinez Refinery is a petroleum refinery that was operated by the Shell Corporation in Martinez. In February 2020, the refinery was sold to PBF. The facility is also known as the Martinez Refinery. It covers 860 acres and can process 157,000 barrels per day. The facility is subject to the expedited BARCT requirements of AB 617 and a 2001 US EPA consent decree.

In 2017, 95 percent of NOx emissions were from the process gas boilers. The turbine boiler is equipped with an SCR system and has NOx emission limits of less than or equal to 5 ppmv NOx at 15% O_2. Three boilers and their associated electrostatic precipitator (ESP) units serve as control devices for the FCCU. A 2001 U.S. EPA consent decree required optimization of NOx emission controls. Following an optimization study by the facility, NOx emission limits for these three boilers were set in 2010 and are shown in the table below.

Table G-3: Boiler Emission Limits

	365 day rolling average (ppmv at 0% O2)	24 hour rolling average (ppmv at 0% O2)
Boiler 1	130.6	168.4
Boiler 2	127.4	156.9
Boiler 3	113.1	142.7

The FCCU at this facility also will be subject to the revisions to Regulation 6, Rule 5 that were recently adopted by the district in response to AB 617 expedited BARCT requirements. While the rule will specifically target emission of condensable particulate matter, NOx contributes to condensable particulate matter in the exhaust stream. The facility will be

[71] https://ceqanet.opr.ca.gov/2020120330/2

required to meet emission limits in the rule revision by 2023. The district considered two scenarios to control FCCU emissions, which are detailed in the table below. The scenario in the recently approved will require the installation of a wet gas scrubber to meet particulate matter emission limits from the FCCU. The basis used to determine costs are available from the BAAQMD.[72]

Table G-4: Cost effectiveness of measures for Martinez Refinery considered in revision of BAAQMD Regulation 6 Rule 5

FCCU Control Options	PM10 Reductions	Capital Cost	Total Annualized Cost	Cost Effectiveness
Expand existing controls to include ESP, feed hydrotreatment, and a catalyst additive	170 tpy	$80 million	$14 million/year	$84,900/ton
Install wet gas scrubber	240 tpy	$255 million	$40 million/year	$165,000/ton

The boilers are also subject to Regulation 9, Rule 10 which has been determined to meet BARCT stringency. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of regional haze, no further reasonable controls are necessary.

Valero Refining Company
Facility ID: 14217311
Nearest Mandatory Federal Class I Area: Point Reyes National Seashore
2017 NEI NOx Emissions: 1013 tpy
2017 NOx Q/d: 19.3

Valero operates a refinery in Benicia. The refinery was originally constructed in 1969 and Valero acquired the facility in 2000. The facility produces jet fuel, diesel, and asphalt. It has a throughput capacity of 170,000 barrels per day. The facility is subject to the expedited BARCT requirements of AB 617.

The largest NOx sources at the facility include natural gas-fired turbines, furnaces, and boilers. NOx emissions are controlled through SCR systems and low NOx burners. BAAQMD Regulation 9, Rule 10 applies to heaters and boilers (except for CO boilers) at refineries and sets the refinery-wide NOx emissions limit at 0.033 lbs NOx per million British thermal units (MMBtu) of heat input (daily average) as well as the facility-wide federal limit of 0.20 lbs NOx/MMBtu of heat input. The refinery does also have an FCCU, which is equipped with a wet gas scrubber and is expected to meet emission limits in the revisions to Regulation 6, Rule 5.

[72] https://www.baaqmd.gov/rules-and-compliance/rules/reg-6-rule-5-particulate-emissions-from-refinery-fluidized-catalytic-cracking-units

Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of regional haze, no further reasonable controls are necessary.

Eastern Kern APCD

The Eastern Kern APCD regulates stationary sources in the eastern portion of Kern County. The jurisdiction of Eastern Kern APCD is designated as nonattainment for the ozone and PM10 NAAQS listed below.

- Severe Nonattainment for 2008 Ozone NAAQS
- Moderate Nonattainment for 2015 Ozone NAAQS
- Serious Nonattainment for 1987 PM10 NAAQS

One facility is in the area under the jurisdiction of the Eastern Kern APCD. The facility is subject to the expedited BARCT requirements of AB 617. The district's Rule 425.3: Portland Cement Kilns (Oxides of Nitrogen) was amended in 2018 to meet federal reasonable available control technology (RACT) requirements. The district also concluded that the amended rule met BARCT stringency. The rule study for this revision is available from Eastern Kern APCD.[73]

A discussion of the facility in Eastern Kern APCD's jurisdiction that was excluded at the third step in the screening process follows.

Cal Portland Mojave Plant
Facility ID: 4789311
Nearest Mandatory Federal Class I Area: Domeland Wilderness Area
2017 NEI NOx Emissions: 1,013 tpy
2017 NOx Q/d: 19.3

Cal Portland's Mojave Plant is a Portland cement plant. The plant began producing cement in 1956. In 2017, ninety-nine percent of NOx emissions were from the kiln. NOx emissions from the kiln are controlled by a selective non-catalytic reduction (SNCR) system with ammonia injection. The facility is subject to the expedited BARCT requirements of California's AB 617 and a 2011 U.S. EPA consent decree that required installation of SNCR and established an emission limit of 2.5 lbs NOx/ton of clinker. The NOx emission limit from the consent decree is included in the Title V permit conditions. Per district staff, the 2013 installation of SNCR at this facility led to a NOx reduction of approximately 1,400 tpy.

The district's Rule 425.3: Portland Cement Kilns (Oxides of Nitrogen) was studied and amended in 2018 following the district's 2017 RACT SIP. The district concluded that the

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[73] *http://www.kernair.org/Documents/Rules/Rules_March_2018/RULE%20425_3_Final_Staff_Report.pdf*

existing rules regulating NOx emissions from the facility are at BARCT stringency. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are reasonable.

Mojave Desert AQMD

The Mojave Desert AQMD is responsible for regulation of stationary sources in the northern portion of San Bernardino County and the eastern portion of Riverside County. The agency's jurisdiction includes the areas designated as nonattainment for ozone and PM NAAQS listed below.

- Severe Nonattainment for 2015 & 2008 Ozone NAAQS (Western Mojave Desert)
- Moderate Nonattainment for PM10 NAAQS (Searles Valley - Trona)
- Moderate Nonattainment for PM10 NAAQS (San Bernardino County/excl. Searles Valley)

Four facilities excluded from further consideration at the third step in the screening process are in jurisdiction of Mojave Desert AQMD including three cement plants and one mineral processing facility. Cement plants are subject to Rule 1161 – Portland Cement Kilns. This rule was amended in 2018. The district concluded this recently amended rule was at BARCT stringency. In 2019, the district also adopted Rule 1157.1 BARCT Requirements for Boilers and Process Heaters Outside the Federal Ozone Nonattainment Area (FONA) in 2019 to meet expedited BARCT requirements for boiler operations at the mineral processing facility located outside of the federal ozone nonattainment area in Searles Valley. A discussion of the four sources follows.

Cemex – Black Mountain Quarry
Facility ID: 4841311
Nearest Mandatory Federal Class I Area: San Gorgonio Wilderness Area
2017 NEI NOx Emissions: 5,420 tpy
2017 NOx Q/d: 101.6

The Cemex – Black Mountain Quarry is a limestone quarry and produces clinker for the Portland cement industry. The Black Mountain Quarry is connected via intra-facility railroad to the Cemex River Plant where the milled clinker is finished and packaged for distribution. The Black Mountain Quarry has two coal-fired pre-calcining kilns, one with a heat output rating of 460 MMBtu/hr and the other with a rating of 625 MMBtu/hr. Fugitive emissions from onsite vehicles account for 57 percent of NOx emissions and the precalcining kilns, collectively, account for 42 percent of NOx emissions.

The kilns were constructed in the late 1990s and went through New Source Review (NSR) at that time. The facility is subject to the expedited BARCT requirements of AB 617 and a 2009

U.S. EPA consent decree. The consent decree established a NOx emission limit of 1.95 lbs/ton of clinker, the 2008 best available control technology (BACT)/lowest achievable emission rate (LAER) limit.

The kilns are also subject to Mojave Desert AQMD's Rule 1161 – Portland Cement Kilns, which was revised in 2018 to meet federal RACT stringency and California BARCT stringency. Onsite vehicles include both on-road and off-road vehicles that are subject to mobile source emission standards established by state and federal agencies. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are reasonable.

Mitsubishi Cement (Cushenberry Plant)
Facility ID: 4921411
Nearest Mandatory Federal Class I Area: San Gorgonio Wilderness Area
2017 NEI NOx Emissions: 1944 tpy
2017 NOx Q/d: 59.7

Mitsubishi Cement is a Portland cement plant. The plant was constructed in 1957 by Henry J. Kaiser. The plant was modernized in 1982 and purchased by the Mitsubishi Cement Corporation in 1988. The facility has a coal-fired 562 MMBtu/hr pre-calcining kiln. Ninety-seven percent of NOx emissions are from the kiln. The kiln was constructed in the early 1980s and went through PSD major source review at that time.

The kiln is subject to Rule 1161 – Portland Cement Kilns, which was revised in 2018 to meet federal RACT stringency and California BARCT stringency. The emission limit in the Title V permit is 2.8 lbs of NOx/ton of clinker. District staff indicate that the most reasonable available controls are in place at the facility. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are necessary.

Cal Portland Oro Grande
Facility ID: 17924211
Nearest Mandatory Federal Class I Area: Cucamonga Wilderness Area
2017 NEI NOx Emissions: 1141 tpy N
2017 NOx Q/d: 27.9

Cal Portland Oro Grande is a Portland cement plant that processes limestone quarried from the site, produces cement clinker from the raw materials, and further processes the clinker into cement products for distribution from the site via truck and rail. The facility has one coal-fired pre-calcining cement kiln. Ninety-nine percent of NOx emissions are from the kiln.

The kiln was constructed in the 2000s and went through NSR at that time and met the 2005 BACT/LAER limits of 2.45 lbs NOx/ton of clinker. The kiln is subject to Rule 1161 – Portland Cement Kilns, which was revised in 2018 to meet federal RACT stringency and California BARCT stringency. Per district staff, this facility has the most reasonable controls already in place. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are necessary.

Searles Valley Mineral
Facility ID: 4838811
Nearest Mandatory Federal Class I Area: Domeland Wilderness Area
2017 NEI NOx Emissions: 1517 tpy
2017 NOx Q/d: 21.3

Searles Valley Mineral processes brine solution from Searles Lake to produce boric acid, sodium carbonate, sodium sulfate, and specialty forms of borax and salt. The facility began operations in the 1870s. The facility operates two coal-fired steam boilers (each with a 1025 MMBtu/hr heat output rating), one natural gas-fired steam boiler (418 MMBtu/hr heat output rating), and one natural gas-fired package steam boiler (126.58 MMBtu/hr heat output rating). The boilers account for about 80 percent of NOx emissions at the facility.

The smallest boiler complies with a BACT emission limit of 9 ppmv. All the boilers are subject to Rule 1157.1 BARCT Requirements for Boilers and Process Heaters Outside the FONA, which was adopted in 2019 to meet the AB 617 expedited BARCT requirements. The three larger boilers are required to be in compliance with this new rule by 2023. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are necessary.

Northern Sierra AQMD

The air pollution control districts of Nevada, Plumas, and Sierra counties merged in 1986 to form the Northern Sierra AQMD. The Northern Sierra AQMD is responsible for regulating stationary sources in these three counties. The western portion of Nevada County is designated nonattainment for the ozone NAAQS and the community of Portola, in the southeastern portion of Plumas County, is designated nonattainment for the PM2.5 NAAQS.

- Serious Nonattainment for 2008 Ozone NAAQS (western Nevada County)
- Moderate Nonattainment for 2015 Ozone NAAQS (western Nevada County)
- Moderate Nonattainment for 2012 PM2.5 NAAQS (Portola only)

One stationary source in the Northern Sierra AQMD jurisdiction was excluded from further consideration at the third step in the screening process. A discussion of that facility follows.

Sierra Pacific Industries – Quincy
Facility ID: 3270411
Nearest Mandatory Federal Class I Area: Caribou Wilderness Area
2017 NEI NOx Emissions: 392 tpy
2017 NOx Q/d: 6.6

Sierra Pacific Industries – Quincy is a sawmill with a biomass cogeneration plant. The facility is in Plumas County but outside the boundaries of the PM2.5 federal nonattainment area. Feedstock includes Ponderosa pine, Sugar pine, White fir, Incense cedar, and Douglas fir. The sawmill produces approximately 210 million board feet (MMBF) of lumber per year. The cogeneration plant produces approximately 27 megawatts (MW) of electricity annually, and 15 to 20 MW are sold to the grid. All NOx emissions come from two wood-fired boilers. Per district staff, NOx emissions are controlled by ammonia injection. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of regional haze, no further controls are necessary.

Shasta County AQMD

The Shasta County AQMD is responsible for regulating emission from stationary sources in Shasta County. All areas under the jurisdiction of the Shasta County AQMD are designated as attainment or unclassified for all NAAQS. Four stationary sources in Shasta County AQMD's jurisdiction were excluded from further consideration at the third step in the screening process. A discussion of these sources follows.

Burney Forest Products
Facility ID: 8411711
Nearest Mandatory Federal Class I Area: Thousand Lakes Wilderness Area
2017 NEI NOx Emissions: 190 tpy
2017 NOx Q/d: 11.2

Burney Forest Products is a 31 MW biomass energy facility. The facility provides process steam to an adjacent sawmill and sells power to Pacific Gas & Electric. All NOx emissions come from two wood-fired boilers. The boilers are equipped with an SNCR unit with anhydrous ammonia injection for NOx control. An initial Title V permit was issued in 1999. Their current Title V permit was issued in 2019 and includes BACT emission limits for NOx (under permit condition 11). Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are necessary.

Lehigh Southwest Cement Company
Facility ID: 1673211
Nearest Mandatory Federal Class I Area: Thousand Lakes Wilderness Area
2017 NEI NOx Emissions: 603 tpy
2017 NOx Q/d: 10.7

Lehigh Southwest Cement is a Portland cement plant originally constructed in 1961 and modernized in 1981. NOx emissions are from the kiln. The facility is subject to a 2019 U.S. EPA Consent Decree limiting NOx emissions to 1.95 lbs /ton clinker with combustion controls or SNCR within 24 months of the effective date of the consent decree. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are necessary.

Sierra Pacific Industries – Burney
Facility ID: 6575511
Nearest Mandatory Federal Class I Area: Thousand Lakes Wilderness Area
2017 NEI NOx Emissions: 157 tpy
2017 NOx Q/d: 8.9

Sierra Pacific Industries – Burney is a sawmill with a 20 MW cogeneration facility. Electricity generated at the facility is sold to the grid and used for onsite operations. All NOx emissions are from one wood-fired boiler. Per district staff, NOx emissions are controlled through ammonia injection, staged combustion controls, flue gas recirculation, and low NOx burners when combusting natural gas at start-up/shutdown. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are necessary.

Wheelabrator Shasta E.C.I.
Facility ID: 1673711
Nearest Mandatory Federal Class I Area: Yolla Bolly-Middle Eel Wilderness Area
2017 NEI NOx Emissions: 536 tpy
2017 NOx Q/d: 9.4

Wheelabrator Shasta is a 49.9 MW biomass facility that generates electricity for the grid. All NOx emissions come from three wood-fired boilers. The facility exclusively combusts biomass and natural gas. Natural gas is not to exceed 10 percent on a monthly basis. Per district staff, NOx emissions are controlled through ammonia injection, staged combustion controls, flue gas recirculation, and low NOx burners when combusting natural gas at start-up/shutdown. The facility is required to tune-up boilers every 5 years. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are necessary.

South Coast AQMD

Six sources are in the jurisdiction of the South Coast AQMD including four petroleum refining facilities, a paper mill, and a steel mill. All six of these facilities are subject to the expedited BARCT requirements of AB 617. The local air district has worked extensively to develop and implement rule revisions to ensure compliance with the AB 617 requirements. These facilities are also located in areas designated as nonattainment for multiple NAAQS and have been the subject of decades of emission control efforts. A discussion of the six sources in South Coast AQMD's jurisdiction that were excluded at the third step of the screening process follows.

California Steel Industries
Facility ID: 4839811
Nearest Mandatory Federal Class I Area: Cucamonga Wilderness Area
2017 NEI NOx Emissions: 125 tpy
2017 NOx Q/d: 7.8

California Steel Industries produces flat-rolled steel from slabs of steel. NOx emissions are primarily from the 24 furnaces in operation, the largest of which accounts for 65 percent of the facility's NOx emissions. The facility also operates boilers, which account for less than 10 percent of emissions. Boilers and annealing furnaces are equipped with low NOx burners and the 529.5 MMBtu/hr furnace has a selective catalytic reduction system. Per district staff, the facility has implemented BACT level controls for all equipment.

By January 2022, the facility is planning to replace two existing 33 MMBtu/hr boilers with two new 32.54 MMBtu/hr boilers to comply with a 5 ppm NOx limit in South Coast AQMD Rule 1146, which is part of the RECLAIM sunsetting program. The facility is also expected to decrease their fuel limit on the 16.7 MMBtu/hr boiler and the 4.185 MMBtu/hr boiler to comply with lower limits in Rule 1146. A 90,000 therm/year limit applies to the larger boiler and a 18,000 therm/year limit applies to the smaller boiler. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are reasonable.

Chevron Products Co.
Facility ID: 4086111
Nearest Mandatory Federal Class I Area: San Gabriel Wilderness Area
2017 NEI NOx Emissions: 729 tpy
2017 NOx Q/d: 14.0

Chevron Products is a refinery in El Segundo that processes crude oil into various petroleum products such as gasoline, diesel, jet fuel, fuel oil, liquefied petroleum gases, and coke. The refinery uses several processes to separate petroleum components in crude oil and to convert heavier and lighter components into more marketable hydrocarbon compounds that are used as blending components for gasoline, diesel, and other products. NOx control equipment includes low NOx burners in heaters/boilers, SCR units, and NOx reducing catalyst in the FCCU. Recently, the facility replaced five heater burners with low NOx burners and the district recently received a proposal from the facility to install SCR on two large heaters.

This refinery is a NOx RECLAIM facility. In 2015, amendments to the RECLAIM Regulation XX, known as the NOx Shave, were enacted to reduce the NOx RECLAIM Trading Credits (RTCs) held by large facilities including petroleum refineries. This rule action is expected to result in a reduction of 12 tpd of NOx from the refineries and other affected facilities by 2023. As a result, several large combustion sources at the Chevron refinery are being modified to lower NOx emissions. Between 2017 and 2019, NOx emissions were reduced from 729 tpy to 640 tpy, likely due to modifications initiated by the NOx Shave.

Additionally, as part of South Coast AQMD's efforts to sunset the NOx RECLAIM program and to implement AB 617 measures, Rule 1109.1 is being developed for all NOx emitting sources at the refineries. Equipment that is not at BARCT levels will have to be modified to meet BARCT limits as described under proposed Rule 1109.1. The implementation of this rule is expected to result in reduction of an additional 7 to 9 tons per day of NOx from the refineries and related facilities.

Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are reasonable.

New Indy Ontario LLC
Facility ID: 17240911
Nearest Mandatory Federal Class I Area: Cucamonga Wilderness Area
2017 NEI NOx Emissions: 137 tpy
2017 NOx Q/d: 7.5

New Indy is a manufacturing facility that produces linerboard and corrugating medium for corrugated board from recycled corrugated containers. They recycle corrugated containers by making old containers into a slurry, cooking the slurry, then adding starch binders that allows for the slurry to be drawn onto a web, dewatered, and pressed into new paper stock between heated rolls. The recycled medium is then sent to box plants throughout the local market. Power and heat for this operation come from a 40.45 MW gas turbine and a

247.3 MMBtu/hr natural gas fired boiler. Ninety-eight percent of NOx emissions are from the gas turbine.

On October 18, 2018, the South Coast AQMD issued New Indy Permits to Construct for the replacement of the turbine and associated SCR with two new identical Combined Heat and Power (CHP) units. Each new CHP unit consists of a gas turbine rated at 174.9 MMBtu/hr, 16.45 MW with a 132.4 MMBtu/hr duct burner. Each new CHP unit is vented to an SCR system to control NOx emissions and an oxidation catalyst to control carbon monoxide CO and VOC emissions. As part of the replacement project, the existing boiler was repurposed to act as a stand-by steam generator. The new units were placed in operation in the fall of 2019. Each CHP unit is subject to a BACT limit of 2 ppm NOx @ 15% O_2.

The boiler is currently vented to an SCR unit and is subject to South Coast AQMD's Rule 1146. The rule requires the boiler to meet a 5 ppm NOx and 5 ppm NH_3 at 3 percent O_2 emission limit no later than January 1, 2021. The facility submitted applications to replace the catalyst of the SCR unit with a new catalyst capable of reducing the NOx emissions from the boiler and ammonia slip from the SCR unit to less than 5 ppm at 3 percent O_2. Permits to construct for the replacement of the SCR catalyst were issued in October 2020 and the catalyst was replaced and put in operation in early December 2020. Currently the facility is in the process of source testing the equipment to demonstrate compliance with the limits.

Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of regional haze, no further controls are reasonable.

Phillips 66 Co/Los Angeles Refinery – Carson
Facility ID: 5682211
Nearest Mandatory Federal Class I Area: San Gabriel Wilderness Area
2017 NEI NOx Emissions: 391 tpy
2017 NOx Q/d: 7.3

Phillips 66 operates a petroleum refinery in Carson that processes crude oil into various petroleum products including gasoline, diesel fuel, jet fuel, fuel oil, liquefied petroleum products, and coke. Boilers and process heaters are the main NOx emission sources at the facility. In the last six years, equipment changes have included the installation of an SCR unit on boiler 11 and the reformer heater, the largest NOx sources at the facility. Crude heater burners were also replaced with ultra-low NOx burners.

This refinery is a NOx RECLAIM facility. In 2015, amendments to the RECLAIM Regulation XX, known as the NOx Shave, were enacted to reduce the NOx RTCs held by large facilities including petroleum refineries. This rule action is expected to result in a reduction of 12 tpd of NOx from the refineries and other affected facilities by 2023. As a result, several large combustion sources at the Phillips 66 Los Angeles Refinery in Carson are being modified to lower NOx emissions.

Additionally, as part of South Coast AQMD's efforts to sunset the NOx RECLAIM program and to implement AB 617 measures, Rule 1109.1 is being developed for all NOx emitting sources at the refineries. This rule is anticipated to be adopted by the end of 2020 and is expected to bring all the NOx emitting sources at refineries to BARCT levels. The implementation of this rule is expected to result in reduction of an additional seven to nine tons per day of NOx from the refineries and related facilities.

Emissions data reported by the facility, show that annual NOx emissions were 225 tpy in 220, which amounts to a reduction of over 40 percent from 2017 emissions and results in a NOx Q/d of 4.2. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are reasonable.

Phillips 66 Co/LA Refinery Wilmington
Facility ID: 6500611
Nearest Mandatory Federal Class I Area: San Gabriel Wilderness Area
2017 NEI NOx Emissions: 471 tpy
2017 NOx Q/d: 8.1

Phillips 66 operates the Los Angeles Refinery in Wilmington that processes crude oil into a variety of specialized road and roofing asphalts, diesel fuel, jet fuel, and gasoline components. The FCCU is the largest NOx source at the facility. Boilers and process heaters also emit NOx. SCR was recently installed on the FCCU. Boilers and heaters are equipped with low NOx burners.

This refinery is a NOx RECLAIM facility. In 2015, amendments to the RECLAIM Regulation XX, known as the NOx Shave, were enacted to reduce the NOx RTCs held by large facilities including petroleum refineries. This rule action is expected to result in a reduction of 12 tpd of NOx from the refineries and other affected facilities by 2023. As a result of this rule action, several large combustion sources at the Phillips 66-Wilmington refinery are being modified to lower NOx emissions.

Additionally, as part of South Coast AQMD's efforts to sunset the NOx RECLAIM program and to implement AB 617 measures, Rule 1109.1 is being developed for all NOx emitting sources at the refineries. This rule is anticipated to be adopted by the end of 2020 and is expected to bring all the NOx emitting sources at refineries to BARCT levels. The implementation of this rule is expected to result in an additional reduction of seven to nine tons per day of NOx from the refineries and related facilities. Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are necessary.

Tesoro Refining and Marketing Co. – Carson and Wilmington
Facility ID: 4073511 (Carson) & 14055211 (Wilmington)
Nearest Mandatory Federal Class I Area: San Gabriel Wilderness Area
2017 NEI NOx Emissions: 661 (Carson) and 749 tpy (Wilmington)
2017 NOx Q/d: 13.0 (Carson) and 13.8 (Wilmington)

The Tesoro Los Angeles Refinery, also known as Marathon Petroleum Corporation Los Angeles Refinery, consists of Tesoro Carson Operations and Tesoro Wilmington Operations facilities. In 2017, Tesoro changed its name to Andeavor. In 2018, Andeavor merged with the Marathon Petroleum Corporation. The name on the permits issued to these two facilities by the South Coast AQMD remains Tesoro Refining and Marketing.

At these facilities, crude oil is converted into gasoline, diesel fuel, jet fuel and other petroleum products. Combined, these refineries have a combined capacity of 363,000 barrels per day. The major NOx emission sources include the FCCU regenerator, cogeneration turbines, boilers, and process heaters. NOx control equipment at the refineries includes low NOx burners in heaters/boilers, SCR units, and NOx reducing catalyst in the FCCU.

The Tesoro Los Angeles Refinery Integration and Compliance (LARIC) Project was initiated in 2017 with the intent to integrate operations at the adjacent Carson and Wilmington refineries through equipment modifications. This project is expected to result in reductions of NOx, SOx, and of PM10 when fully implemented. A large portion of these reductions are the result of the shutdown of the FCCU and associated heaters at Tesoro Wilmington Operations. The FCCU shutdown was completed in October 2018. For the 2020 calendar year, combined annual NOx emissions from the Carson and Wilmington facilities were 424 tons lower than in 2017. The entire project is expected to be completed by the end of 2023.

Tesoro's Los Angeles Refinery operations at Carson and Wilmington are subject to the NOx RECLAIM program. In 2015, amendments to the RECLAIM Regulation XX, known as the NOx Shave, were enacted to reduce the NOx RTCs held by large facilities including petroleum refineries. This rule action is expected to result in a reduction of 12 tpd of NOx from the refineries and other affected facilities by 2023. As a result, several combustion sources at the Tesoro refineries are being modified to lower NOx emissions.

Additionally, as part of South Coast AQMD's efforts to sunset the NOx RECLAIM program and to implement AB 617 measures, Rule 1109.1 is being developed for all NOx emitting sources at the refineries. This rule is anticipated to be adopted by the end of 2020 and is expected to bring all the NOx emitting sources at refineries to BARCT levels. The implementation of this rule is expected to result in an additional reduction of seven to nine tons per day of NOx from the refineries and related facilities.

Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are reasonable.

Torrance Refining (formerly ExxonMobil)
Facility ID: 17922111
Nearest Mandatory Federal Class I Area: San Gabriel Wilderness Area
2017 NEI NOx Emissions: 924 tpy
2017 NOx Q/d: 17.6

Torrance Refining processes crude oil into petroleum products including gasoline, diesel, jet fuel, fuel oil, and liquefied petroleum gases. The largest NOx emission sources are the FCCU regenerator, boilers, and heaters. NOx control equipment at the refinery includes low NOx burners in heaters/boilers, SCR units, and NOx reducing catalyst in the FCCU. In late 2018, permitting was completed for installation of a new SCR for a pre-NSR boiler and a reformer heater.

This refinery is a NOx RECLAIM facility. In 2015, amendments to the RECLAIM Regulation XX, known as the NOx Shave, were enacted to reduce the NOx RTCs held by large facilities including petroleum refineries. This rule action is expected to result in a reduction of 12 tpd of NOx from the refineries and other affected facilities by 2023. As a result, several large combustion sources at the Torrance refinery are being modified to lower NOx emissions.

Additionally, as part of South Coast AQMD’s efforts to sunset the NOx RECLAIM program and to implement AB 617 measures, Rule 1109.1 is being developed for all NOx emitting sources at the refineries. This rule is anticipated to be adopted by the end of 2020 and is expected to bring all the NOx emitting sources at refineries to BARCT levels. The implementation of this rule is expected to result in an additional reduction of seven to nine tons per day of NOx from the refineries and related facilities.

Based on this information, this facility will be excluded from further consideration because a full four-factor analysis would likely result in the conclusion that, for the purposes of the regional haze program, no further controls are reasonable.

H. Discussion of Four Reasonable Progress Factors for Selected Sources

The following discussion is intended to highlight the consideration of the four reasonable progress factors embodied in California's rule making process.

On-Road Mobile Source Control Measures

Heavy-Duty Trucks

Three key regulatory measures were developed through the integrated planning process during this regional haze planning period and are intended to reduce emissions from on-road heavy-duty vehicles. The Heavy-Duty Omnibus Regulation aims to reduce emissions by implementing more stringent emission standards. The Heavy-Duty Inspection and Maintenance (Heavy-Duty I/M) Program Regulation aims to reduce emissions by implementing a comprehensive enforcement program to ensure that emission standards are met for the operational life of the vehicle. The Advanced Clean Trucks (ACT) Regulation aims to reduce emissions by accelerating the transition to zero-emission vehicle technologies. Implementation of these measures is projected to lead to significant NOx emission reductions that will foster progress towards meeting air quality, climate, and community health goals in California. A detailed discussion of the four reasonable progress factors as they relate to these measures follows.

Heavy-Duty Omnibus

Information on each of the four reasonable progress factors was obtained from publicly available documentation prepared or compiled by CARB staff for the development of the Heavy-Duty Omnibus Regulation. A more detailed impact analysis of the concepts in the regulation is included in the Standardized Regulatory Impact Assessment (SRIA) prepared for the proposal of this regulation. The SRIA was released for stakeholder review in January 2020. Information on each of the four factors is summarized below.

The full text of the SRIA and other rule-making documents associated with the Heavy-Duty Omnibus Regulation are available online: *https://ww2.arb.ca.gov/rulemaking/2020/hdomnibuslownox*.

Heavy-Duty Omnibus: Cost of Compliance

The regulation will significantly reduce tailpipe NOx emissions during most vehicle operating modes including high speed steady-state, transient, low load urban driving, and idling. The emission reductions will be achieved by the implementation of a suite of measures that include more stringent engine emission standards, more comprehensive certification procedures, and promotion of more timely repairs through extended warranty and useful life provisions. The magnitude of the NOx reductions from this regulation will scale up over time in the near-term due to fleet turnover. The statewide NOx emissions benefits associated with the regulation will amount to 23.2 tons per day of NOx in 2031.

The regulation is expected to cost $17.52 million in the first year of implementation and collectively total of $1.11 billion for implementation in 2022 through 2032. Direct incremental costs associated with implementation of the regulation are shown in Table H-1.

Engine manufacturers will bear increased costs associated with development and manufacturing of new engines and emission control technologies, testing and certification requirements, durability demonstration requirements, warranty repairs, and reporting requirements. Manufacturers will offset these costs through sales of new vehicles.

Truck owners and operators will bear increased expenses associated with increased truck prices and operating expenses. Per truck, these increased expenses are expected to range from $602 to $3,814 for purchases of model year 2024 to 2026 vehicles and $744 to $8,237 for purchases of model year 2027 or later vehicles. These costs will be offset by savings associated with longer warranty periods, longer useful lives of vehicles, and improved durability. The average lifetime per vehicle savings is estimated to be $1,279 for purchases of model year 2022 to 2026 vehicles and $3,345 for purchases of model year 2027 or later vehicles.

The Heavy-Duty Omnibus Regulation will result in a reduction of 28,617 tons of NOx between 2022 and 2032, relative to emissions projected under current regulatory scenario. The total cost of implementing the measures in this regulation are estimated to be $1.11 billion between 2022 and 2032. Based on this information, the total cost effectiveness of this regulation for the 2022 to 2032 period amounts to $38,788 per ton of NOx.

In addition to the reduction in direct emissions of NOx, the regulation will have a significant cost savings in avoided adverse health outcomes. The estimated costs savings of avoided adverse health outcomes amount to $3.15 billion for the 2022 to 2032 period.

Table H-1: Estimated Direct Incremental Costs (in Millions 2018$) Relative to Baseline Regulatory Scenario for Calendar Years 2022 through 2032

Year	Standards, Certification, and New Technology	Annual DEF* Consumption	In-Use Amendments	Lengthened Warranty	Lengthened Useful Life	Durability Demonstration	EWIR** Amendments	ABT***	NOx Data Reporting	Total Costs
2022	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$17.52	$0.00	$0.00	$17.52
2023	$1.73	$0.00	$0.00	$0.00	$0.00	$8.72	$18.43	$0.00	$0.85	$29.73
2024	$1.94	$0.00	$0.10	$0.00	$0.00	$0.00	$18.73	$0.10	$0.14	$21.02
2025	$34.07	$0.94	$0.10	$0.00	$0.00	$0.00	$19.47	$0.02	$0.24	$54.84
2026	$35.73	$1.89	$0.10	$0.00	$0.00	$8.24	$19.57	$0.02	$0.95	$66.50
2027	$29.48	$2.84	$0.10	$75.73	$17.32	$0.00	$4.68	$0.02	$0.67	$130.86
2028	$58.22	$4.01	$0.10	$75.73	$17.32	$0.00	$4.69	$0.02	$1.41	$161.30
2029	$48.24	$5.16	$0.10	$76.20	$17.54	$0.00	$4.71	$0.02	$2.15	$154.13
2030	$46.95	$6.32	$0.10	$76.20	$17.61	$0.00	$4.72	$0.02	$2.90	$154.81
2031	$46.33	$7.47	$0.10	$77.23	$17.84	$0.00	$4.78	$0.02	$3.66	$157.43
2032	$46.37	$8.64	$0.10	$79.40	$18.34	$0.00	$4.92	$0.02	$4.44	$162.23
Total	**$349.07**	**$37.28**	**$0.94**	**$460.29**	**$105.97**	**$16.96**	**$122.22**	**$0.25**	**$17.39**	**$1,110.39**

**DEF is diesel exhaust fluid*

***EWIR is Emission Warranty Information Reporting*

****ABT is average, banking, and trading*

Heavy-Duty Omnibus: Time Necessary for Compliance

The low NOx engine standard proposed in the Heavy-Duty Omnibus Regulation will take affect with model year 2024 vehicles. Vehicles built for sale in California for model year 2024 through 2026 will be required to meet the 0.05 g/bhp-hr NOx standard during in-use testing. Diesel-cycle engines for these model years will also be required to meet the 10 g/hr standard during idling. Starting with model year 2027, vehicles will be required to meet the 0.02 g/bhp-hr NOx standard during in-use testing.

Heavy-Duty Omnibus: Energy and Non-Air Quality Environmental Impacts

As required by the California Environmental Quality Act (CEQA), CARB staff completed a thorough environmental analysis of all the measures articulated in the 2016 State SIP Strategy, including those in the Heavy-Duty Omnibus Regulation. The environmental analysis evaluated potentially significant environmental effects related to implementation of measures and their associated reasonably foreseeable compliance responses. The environmental analysis was released for public review in March 2017. CARB staff determined implementation of the proposed measures would result in minimal adverse physical changes to the environment, aside from the air quality benefits discussed earlier.

The full text of the environmental analysis is available online: *https://ww3.arb.ca.gov/planning/sip/2016sip/rev2016statesip_ceqa.pdf*.

Heavy-Duty Omnibus: Remaining Useful Life

Under current regulation, the regulatory useful life of heavy-duty vehicles and their engines is 10 years. The Heavy-Duty Omnibus includes a provision to extend the regulatory useful lives for heavy-duty engines beginning with model year 2027 (Table H-2). An additional extension will apply in 2031. The intention of this provision is to ensure engines and emission control technologies are durable enough to function properly over the modern service life of the engines. The provision to extend the regulatory useful life will reduce emissions over the service life of the engine and require manufacturers to demonstrate the durability of engines and emission controls over a longer period.

Table H-2: Current and Proposed Useful Life for Heavy Duty Engines Beginning Model Year 2027

Vehicle Class (Engine)	Current Useful Life	Proposed Useful Life
Class 4 - 8 (Otto-Cycle)	110,000 miles/10 years	155,000 miles/12 years
Class 4 - 5 (Diesel-Cycle)	110,000 miles/10 years	190,000 miles/12 years
Class 6 - 7 (Diesel-Cycle)	185,000 miles/10 years	270,000 miles/11 years
Class 8 (Diesel-Cycle)	435,000 miles/10 years/22,000 hours	600,000 miles/11 years/30,000 hours

Heavy-Duty Inspection and Maintenance Program

The Heavy-Duty I/M regulation includes a suite of measures aimed at ensuring emission control systems on heavy-duty vehicles are maintained for the operational life of the vehicle. The regulation includes the following requirements:

- Vehicle owner reporting requirement: Owners of heavy-duty vehicles operating in California will be required to report their vehicle information to CARB, pay the annual program compliance fee, and obtain a compliance certificate by July 2023.
- Periodic inspection requirement: Owners of heavy-duty vehicles operating in California will be required to periodically submit vehicle inspection data to CARB. Owners of on-board diagnostics (OBD) equipped vehicles will be required to submit OBD data to CARB, and non-OBD equipped vehicles will be required to submit biannual smoke opacity tests and visual inspection reports.
- Heavy-Duty I/M-approved tester requirement: Individuals registered with CARB as approved testers will be able to perform vehicle compliance tests on vehicles subject to the regulation. Individuals can complete the required CARB training and obtain a tester credential. Credentials will need to be renewed every two years.
- Heavy-Duty I/M compliance certification requirement: Owners will be required to have a valid compliance certificate with the vehicle while it is operating in California. Operators will be required to present the valid compliance certificate to enforcement staff upon request. Compliance certificates will need to be renewed annually.
- Heavy-Duty I/M roadside monitoring: To assist with enforcement and improve program compliance, CARB has developed a roadside monitoring system. A network of roadside monitors will be deployed throughout the State. Vehicles flagged by a roadside monitoring system will be required to submit documentation to verify their vehicles comply with program requirements. ALPR cameras will be used to detect potentially non-compliant vehicles. Vehicles without a valid compliance certificate will be issued a non-compliance citation. These systems operate autonomously and can be controlled remotely, which will significantly increase the program compliance inspection coverage compared to the current roadside inspections, which rely on the physical field presence of CARB staff.
- Heavy-Duty I/M field inspections: CARB staff will perform field inspections to verify compliance as part of the enforcement effort. During a field inspection, an operator will be required to allow CARB field inspectors to check the vehicle emissions control systems and perform emissions testing such as smoke opacity or OBD testing. Vehicles not in compliance with the program requirements would be issued a citation to fix the non-compliance issue. California Highway Patrol officers will also have authority to

inspect vehicles, verify that operators have compliance certificates on board, and issue citations.

- Freight contractor requirement: Freight contractors, brokers, and facility operators will be required to verify compliance of vehicles contracted to move their freight in California or operate on their properties in California. Freight entities will also be required to maintain records of their actions to comply with the requirements of the Heavy-Duty I/M Program.

- Certification process for OBD testing devices: CARB will develop a process to certify OBD test devices used to scan OBD systems and for submission of compliance data.

Information on each of the four reasonable progress factors was obtained from publicly available documentation prepared or compiled by CARB staff for the Heavy-Duty I/M Program Regulation. A more detailed impact analysis of the measures in the regulation is articulated in the standardized regulatory impact assessment (SRIA) prepared for the proposal of this regulation. The SRIA was released for stakeholder review in July 2021. Information on each of the four factors is summarized below.

The full text of the rulemaking documents including the SRIA developed for the Heavy-Duty I/M regulation are available online: *https://ww2.arb.ca.gov/rulemaking/2021/hdim2021*

Heavy-Duty Inspection and Maintenance: Cost of Compliance

Vehicle owners will bear costs associated with reporting vehicle testing, compliance certification fees, and vehicle repairs. Some fleet operators may also have costs associated with training in-house testing staff. Owners with OBD-equipped vehicles will realize some costs savings by avoiding the smoke opacity tests previously required by the periodic smoke inspection program (PSIP) program. As shown in Table H-3, the total direct incremental costs to vehicle owners from implementation of the proposed regulation is expected to be $2.08 billion for the 2023 to 2037 period, with annual costs peaking in 2024 at $350 million. The peak annual costs in 2024 occur when implementation of the initial periodic testing requirements begins. Following 2024, total costs are projected to be lower mainly due to lower projected repair costs.

Due to the variable annual costs and emissions benefits, the cost-effectiveness of the proposed regulation varies depending on the time period considered. The annual statewide emission benefits from implementation of the HD I/M program are expected to be significant, amounting to 30.3 tpd of NOx in 2024, 71.6 tpd NOx in 2027, and 81.3 tpd of NOx in 2031. Taking these costs and emission benefits into consideration, the annual cost effectiveness for the Heavy-Duty I/M program is projected to be $31,677/ton of NOx in 2024, $5,209/ton of NOx in 2031, and $4,428/ton of NOx in 2037.

In addition to the reduction in direct emissions of NOx, the proposed regulation will have a significant cost savings in avoided adverse health outcomes. For the 2023 to 2037 period, the estimated costs savings of avoided adverse health outcomes amount to $33 billion.

Table H-3: Estimated Direct Costs (in 2020$) of the Proposed HD I/M Program Relative to Baseline for 2023 to 2037

Year	Reporting	Testing	Tester Training	Compliance Certification	Repairs	Total
2023	$3,321,000	$1,941,000	$29,446,000	$23,765,000	$36,900,000	$95,373,000
2024	$2,416,000	$115,730,000	$16,015,000	$28,102,000	$181,067,000	$350,331,000
2025	$2,198,000	$61,300,000	$16,606,000	$28,740,000	$85,441,000	$194,285,000
2026	$2,000,000	$59,196,000	$17,096,000	$29,309,000	$59,076,000	$166,677,000
2027	$1,814,000	$57,317,000	$17,541,000	$29,807,000	$42,639,000	$149,119,000
2028	$1,635,000	$55,490,000	$17,894,000	$30,214,000	$37,608,000	$142,841,000
2029	$1,468,000	$53,704,000	$18,132,000	$30,526,000	$35,949,000	$139,779,000
2030	$1,315,000	$51,957,000	$18,243,000	$30,740,000	$35,226,000	$137,481,000
2031	$1,193,000	$50,786,000	$18,423,000	$31,011,000	$34,722,000	$136,135,000
2032	$1,071,000	$49,579,000	$18,511,000	$31,256,000	$34,661,000	$135,079,000
2033	$953,000	$48,486,000	$18,589,000	$31,471,000	$34,600,000	$134,098,000
2034	$845,000	$47,481,000	$18,625,000	$31,675,000	$34,527,000	$133,154,000
2035	$743,000	$46,432,000	$18,571,000	$31,830,000	$34,546,000	$132,122,000
2036	$663,000	$45,813,000	$18,583,000	$32,026,000	$34,574,000	$131,659,000
2037	$592,000	$445,316,000	$18,581,000	$32,255,000	$34,648,000	$131,392,000
Total	$22,227,000	$1,190,528,000	$280,856,000	$452,727,000	$756,184,000	$2,309,525,000

Heavy-Duty Inspection and Maintenance: Time Necessary for Compliance

Implementation of the Heavy-Duty I/M regulation will occur in three phases. The first implementation phase will begin in January 2023. The second implementation phase will begin in July 2023. The third and final implementation phase will begin in 2024. Table H-4 provides an overview of the implementation timeline and the key measures that will take effect in each phase.

Table H-4: Description of Implementation Phases for HD I/M Program

Phase	Start Date	Measures
1	January 2023	Vehicle screening at field sites Vehicle owners establish accounts in HD I/M database Sunset HDVIP
2	July 2023	Enforcement of compliance certificate requirements CA DMV registration holds for non-compliant vehicles Requirements for freight entities
3	2024	Periodic testing requirements Certified devices required to obtain data for OBD submissions Sunset PSIP

Heavy-Duty Inspection and Maintenance: Energy and Non-Air Quality Environmental Impacts

Environmental impacts of implementing the Heavy-Duty I/M regulation were considered following the procedures laid out in CEQA and are fully articulated in the Initial Statement of Reasons (ISOR) developed by CARB staff for the proposed regulation. The ISOR was released for public review on October 8, 2021. Implementation will not result yield any new, significant energy or non-air quality environmental impacts.

The full text of the Environmental Analysis is available online in Chapter VII of the ISOR: *https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2021/hdim2021/isor.pdf*

Heavy-Duty Inspection and Maintenance: Remaining Useful Life

The regulatory useful life for vehicles that will be subject to the Heavy-Duty I/M program is 10 years. Under the provisions in a separate action, the Heavy-Duty Omnibus Regulation, the regulatory useful life will be increased. The Heavy-Duty I/M program will not impact the useful life of affected sources, rather it will establish an effective enforcement pathway to ensure heavy-duty vehicles operating in California meet emission limits and emission control systems are maintained and operating as intended for the duration of their operational life.

Advanced Clean Trucks

Information on each of the four reasonable factors was obtained from publicly available documentation prepared or compiled by CARB staff for the development of the ACT Regulation. A more detailed impact analysis of the concepts proposed in the regulation is articulated in the SRIA. The SRIA for this proposed regulation was released for stakeholder review in August 2019. Information on each of the four factors is summarized below.

The full text of the SRIA and other rule-making documents associated with the ACT Regulation are available online:
https://ww2.arb.ca.gov/rulemaking/2019/advancedcleantrucks.

Advanced Clean Trucks: Cost of Compliance

Manufacturers will bear the cost of developing and deploying new technologies. Costs will be recovered through sales of vehicles equipped with new technologies and avoided implementation cost obligations for the Internal Combustion Engine (ICE) Phase 2 Greenhouse Gas Standards. Truck and bus owners will bear costs associated with transitioning their fleets. Cost savings for owners may be realized through a lower cost of operating and maintaining battery-electric vehicles over the vehicle lifetime as well as lower vehicle registration fees. Owners with their own charging or hydrogen fueling stations may recover additional costs through CARB’s Low Carbon Fuel Standard (LCFS) program and lower electricity rates established by power suppliers for commercial zero emission vehicle deployment.

As shown in Table H-5, total costs for the implementation of the regulation will increase during the first years of implementation with annual incremental costs peaking at $60 million in 2028. Beginning in 2030, the implementation of the regulation is projected to result in annual incremental cost savings.

Emissions benefits are expected from the onset of implementation and will increase as an increased number of internal combustion vehicles are replaced with zero emission vehicles. The cost-effectiveness of the proposed regulation will vary widely depending on the period considered. In 2031, the proposed regulation is expected to yield an emission benefit of 5 tpd NOx relative to the baseline regulatory emission scenario. By 2040 the emission benefit is projected to be 17 tpd NOx.

Table H-5: Estimated Direct Incremental Costs (in Millions 2018$) Relative to Baseline

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Manufacturer ZEV Price	$0	$0	$0	$0	$43	$55	$66	$136	$181	$224	$259	$263
Manufacturer ICE Phase 2 Costs Avoided	$0	$0	$0	$0	-$9	-$12	-$14	-$43	-$13	-$18	-$23	-$23
Manufacturer ZEP Certification	$0.00	$0.00	$0.00	$0.00	$0.18	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Fleet Reporting	$2.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Fleet Sales & Excise Taxes	$0	$0	$0	$0	$4	$5	$6	$14	$19	$23	$27	$27
Fleet Fuel Costs	$0	$0	$0	$0	-$9	-$21	-$39	-$70	-$120	-193	-$294	-$390
Fleet LCFS Revenue	$0	$0	$0	$0	-$6	-$14	-$23	-$40	-$66	-$103	-$150	-$198
Fleet Maintenance Costs	$0	$0	$0	$0	-$3	-$7	-$12	-$21	-$35	-$54	-$80	-$105
Fleet Maintenance Bay Upgrades	$0	$0	$0	$0	$0	$1	$2	$4	$7	$10	$14	$18
Fleet Midlife Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fleet Infrastructure	$0	$0	$0	$0	$6	$15	$26	$50	$85	$133	$194	$256
Fleet Transitional Costs	$0	$0	$0	$0	$1	$1	$3	$4	$6	$6	$0	$0
Fleet Registration Fees	$0	$0	$0	$0	$0	$0	$0	-$1	-$1	-$3	-$6	-$8
Total	$2.4	$0	$0	$0	$28	$23	$13	$34	$60	$25	-$51	-$161

In addition to the reduction in direct emissions of NOx, the proposed regulation will have a significant cost savings in avoided adverse health outcomes and social costs of carbon. For the 2020 to 2040 period, the estimated costs savings of avoided adverse health outcomes amount to $5.5 billion and the estimated avoided social costs of carbon range from $238.8 million to $1 billion, depending on the discount rate.

Advanced Clean Trucks: Time Necessary for Compliance

The sales requirement will begin with model year 2024 vehicles and increase incrementally until model year 2030. The sales percentage schedule, shown in Table H-6, was developed to account for current market developments and trajectories for suitable technology developments. Pickup truck sales are excluded from Class 2b-3 sales requirements until model year 2027 to account for concerns raised by stakeholders about highly variable towing needs and associated range impacts. Class 4 through 8 straight trucks and shuttles are well-suited for electrification due to low average range needs, lower weight and payload concerns, and the typical return to base operations allowing for centralized charging. Sales requirements for Class 7 and 8 tractors will be excluded until model year 2027 because vehicles in this category are more challenging to electrify due to longer range needs, higher payload needs, and charging infrastructure needs.

Table H-6: Proposed Sales Percentage Requirements for Zero Emission Vehicles by Model Year

Model Year	Class 2B-3	Class 4-8 (exclusive of Class 7-8 Tractors)	Class 7-8 Tractors
2024	3% (excluding pickups)	7%	0%
2025	5% (excluding pickups)	9%	0%
2026	7% (excluding pickups)	11%	0%
2027	9%	13%	9%
2028	11%	24%	11%
2029	13%	37%	13%
2030 and later	15%	50%	15%

Advanced Clean Trucks: Energy and Non-Air Quality Environmental Impacts

As required by CEQA, CARB staff completed an environmental assessment of the measures proposed in the ACT Regulation. The environmental assessment included consideration of energy and non-air quality environmental impacts. Impacts associated with construction of new and modified facilities and infrastructure may occur with implementation of the proposed regulation. These impacts may include a temporary increase in energy demand, temporary presence of construction noise, temporary construction traffic, temporary increase in handling of hazardous materials during construction activity, decreased demand for fossil fuels, and increased demand for extracted minerals like lithium and platinum.

The preliminary environmental assessment was released for public comment October 22, 2019 and the review period ended December 9, 2019. The full text of the preliminary analysis is available online: *https://ceqanet.opr.ca.gov/Project/2018052041*.

The final environmental analysis was released June 23, 2020. The full text of the final analysis is available online:
https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2019/act2019/finalea.pdf.

Advanced Clean Trucks: Remaining Useful Life

Limited data are available on the useful life of battery-electric vehicles. Currently manufacturers offer warranties of eight or more years and up to 300,000 miles. Degradation and reduced energy capacity are expected to occur over the life of batteries in zero-emission vehicles. To address the natural battery degradation, some form of rebuilding, refurbishment, or replacement will be necessary at the midlife of zero-emission vehicles. Table H-7 shows the expected frequency of midlife rebuilds estimated by CARB staff for vehicle classes included in the proposed regulation. At the end of their first useful life, batteries from mobile sources can be repurposed for use in stationary storage towers.

Table H-7: Estimated Frequency of Engine Rebuilds for Vehicle Classes

Vehicle Class	Technology	Midlife Rebuild Occurrence
2B-3	Gasoline	Not necessary
2B-3	Diesel	Not necessary
2B-3	Battery-Electric	Not necessary
4-5	Diesel	Year 13
4-5	Battery-Electric	Year 10
6-7 (excluding tractors)	Diesel	Year 17
6-7 (excluding tractors)	Battery-Electric	Year 10
8 (excluding tractors)	Diesel	Year 18
8 (excluding tractors)	Battery-Electric	Year 14
7-8 tractors	Diesel	Year 18
7-8 tractors	Battery-Electric	Years 5, 13, 20
7-8 tractors	Fuel Cell Electric	Years 7, 14, 21

Light-Duty Vehicles

California has continued efforts to foster the development of new emission control technologies and implement strategies to reduce emissions from light-duty vehicles. California is currently developing the Advanced Clean Cars (ACC) II regulations aimed at reducing criteria pollutant and greenhouse gas emissions from vehicles beyond the 2025 model year. The ACC II regulations will include low emission vehicle (LEV) IV emissions standards and Zero Emission Vehicle (ZEV) measures aimed at further reducing emissions from vehicles powered by internal combustion engines and accelerating the transition to vehicles equipped with zero emission technologies, respectively.

Advanced Clean Cars II

Information on each of the four reasonable progress factors was obtained from publicly available documentation prepared or compiled by CARB staff for the development of the ACC II regulations. A detailed analysis of the concepts in the proposed regulation is included in the SRIA, which was released for public review on January 26, 2022. Information on each of the four factors is summarized below.

The full text of the SRIA is available online:
https://www.dof.ca.gov/Forecasting/Economics/Major_Regulations/Major_Regulations_Table/.

More information about the Advanced Clean Cars II rulemaking is available online:
https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/advanced-clean-cars-ii

Advanced Clean Cars II: Cost of Compliance

The costs associated with the implementation of the proposed ACC II regulation include vehicle purchase costs, registration and insurance, installation of charging stations, and fuel expenses. Costs will be offset by direct savings associated with reduced vehicle maintenance expenses and reduced fuel expenses (relative to gasoline).

The ACC II regulations will reduce NOx emissions through increasingly stringent emission standards for gasoline powered passenger vehicles and requirements to increase the penetration of zero emission vehicles. The emission benefits will scale up over the course of the implementation period as vehicle turnover occurs and an increasing number of vehicles equipped with zero emission technologies are added to the state's vehicle population. Implementation of the ACC II regulations are expected to decrease statewide NOx emissions by 0.59 tpd in 2026, the first year of implementation, and 27.96 tpd in 2040, the final year of implementation, relative to baseline (business as usual) emission scenarios. The emissions benefits are expected to amount to a total of 65,577 tons of NOx between 2026 and 2040.

Consumers will bear direct costs for implementation. The average retail price for the purchase of a new vehicle is expected to increase over the implementation period, ranging from $743 in 2026 to $1,968 in 2035 through 2040. The end of implementation period is 2040 when all new passenger vehicles sold in California will be zero emission vehicles. By addition to the purchase cost of the new vehicle, other costs to the consumer include electricity or hydrogen to power the vehicle, as well as insurance and registration expenses which will scale up with the vehicle costs. The costs of ownership associated with implementation of the ACC II regulation are shown in Table H-8.

Table H-8: Statewide Costs (in Millions 2020$) of Ownership for Implementation of ACC II Regulation, Relative to Baseline

	Vehicle & Plug	Sales Tax	Electricity	Hydrogen	Insurance	Registration	Total Cost
2026	$412	$140	$388	$0	$70	$37	$1,048
2027	$982	$193	$1,001	$0	$168	$94	$2,438
2028	$1,667	$233	$1,881	$0	$284	$169	$4,234
2029	$2,446	$264	$3,034	$0	$414	$263	$6,421
2030	$3,298	$289	$4,248	$384	$559	$374	$9,153
2031	$4,059	$398	$5,753	$1,093	$764	$526	$12,592
2032	$4,672	$401	$7,421	$1,735	$970	$691	$15,890
2033	$5,160	$398	$9,307	$2,251	$1,171	$867	$19,154
2034	$5,552	$397	$11,402	$2,728	$1,371	$1,055	$22,505
2035	$5,867	$396	$13,700	$3,155	$1,568	$1,256	$25,943
2036	$5,862	$396	$15,911	$3,647	$1,767	$1,458	$29,041
2037	$5,851	$398	$17,926	$4,121	$1,966	$1,661	$31,923
2038	$5,855	$399	$19,576	$4,578	$2,096	$1,827	$34,331
2039	$5,865	$401	$21,003	$5,017	$2,129	$1,938	$36,352
2040	$5,884	$402	$22,198	$5,439	$2,047	$1,974	$37,944
Total	$63,434	$5,104	$154,748	$34,148	$17,345	$14,191	$288,970

Costs of ownership will be offset by reduced expenses for vehicle maintenance, gasoline, and vehicle-to-grid services (Table H-9). On a per mile basis, the average electricity costs for operating battery electric vehicles are expected to be nearly 40 percent lower than the cost of fuel to operate comparable gasoline powered vehicles. Hydrogen costs are expected to decrease over the implementation period and, by 2035, the average hydrogen fuel costs for operation of fuel cell vehicles are projected to be lower than the operation of comparable gasoline vehicles. A subset of zero emission vehicle owners with access to bi-directional charging devices and compatible vehicles will be able to participate in vehicle to grid services. Initially, this subset of vehicle owners is assumed to be 1 to 2% but scales up to 25% by 2035. By 2033, the statewide savings to zero emission vehicle owners are projected to exceed the statewide costs.

Table H-9: Statewide Savings (in Millions 2020$) of Ownership for Implementation of ACC II Regulation, Relative to Baseline

	Gasoline	Maintenance & Repair	Vehicle to Grid Services	Total Savings
2026	$605	$156	$0	$762
2027	$1,569	$400	$2	$1,971
2028	$2,906	$732	$6	$3,644
2029	$4,630	$1,153	$14	$5,797
2030	$6,744	$1,608	$26	$8,377
2031	$9,644	$2,179	$104	$11,927
2032	$12,821	$2,811	$209	$15,841
2033	$16,153	$3,462	$419	$20,034
2034	$19,691	$4,162	$770	$24,624
2035	$23,448	$4,884	$1,315	$29,647
2036	$26,955	$5,609	$2,105	$34,669
2037	$30,336	$6,337	$2,896	$39,569
2038	$33,713	$6,912	$3,687	$43,772
2039	$35,656	$7,247	$4,476	$47,380
2040	$37,789	$7,254	$5,261	$50,304
Total	$262,120	$54,906	$21,291	$338,317

The cost effectiveness of the regulation varies annually because costs and emissions benefits vary over the course of the implementation period. Following implementation of the ACC II regulation, a net cost savings is projected beginning in 2033 and continuing through 2040 while the emissions benefits are projected to continue to scale up as low and zero emission vehicles account for an increasing share of the on-road vehicle population.

For the 2026 to 2040 period, the estimated costs savings of avoided adverse health outcomes amount to $14.6 billion and the estimated avoided social costs of carbon are estimated to range from $10.9 billion to $46 billion, depending on the discount rate.

Advanced Clean Cars II: Time Necessary for Compliance

Implementation of the LEV IV and ZEV measures included in the ACC II regulation will occur in phases. The LEV IV measures will be phased in over three years. For the fleet average, the percent of zero emission vehicles allowed for inclusion in the calculation will be reduced to 50 percent in 2026 and 25 percent in 2027. In 2028 and beyond, zero emission vehicles will no longer be included in fleet averages. The revised emission standards and certification testing procedures will apply beginning in model year 2026. The percent of vehicles in manufacturers' fleets that must meet the proposed standards increases from 30 percent in model year 2026, 60 percent in model year 2027, and 100 percent in model year 2028.

The durability and warranty requirements for new ZEVs will be applicable beginning in model year 2026. The ZEV sales requirement will be phased in over ten years. ZEVs must account for an increasing percent of manufacturers' production volume of passenger cars and light-duty trucks. As shown in Table H-10, the percentage requirement increases from 26 percent in model year 2026 to 100 percent in model year 2035 and beyond.

Table H-10: Annual ZEV Production Volume Requirement for Applicable Model Year

Model Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Percentage Requirement	26%	34%	43%	51%	61%	76%	82%	88%	94%	100%

Advanced Clean Cars II: Energy and Non-Air Quality Environmental Impacts

As required by CEQA, an environmental assessment of the measures proposed in the ACC II regulation was completed. The environmental assessment included consideration of energy and non-air quality environmental impacts. Like the ACT Regulation, impacts associated with construction of new and modified facilities and infrastructure may occur with implementation. These impacts may include a temporary increase in energy demand, temporary presence of construction noise, temporary construction traffic, temporary increase in handling of hazardous materials during construction activity, decreased demand for fossil fuels, and increased demand for extracted minerals like lithium and platinum.

The concepts included in the proposed ACC II regulation were initially detailed in CARB's 2016 State SIP Strategy document. Environmental Analysis for the concepts in the 2016 State SIP Strategy was released for public review in March 2017. The full text of the environmental analysis is available online:
https://ww3.arb.ca.gov/planning/sip/2016sip/rev2016statesip_ceqa.pdf.

Advanced Clean Cars II: Remaining Useful Life

The measures in the ACC II regulation are aimed at limiting emissions from new vehicles beginning in model year 2026 by ensuring that new vehicles equipped with internal combustion engines meet stringent emissions standards representative of real-world operating conditions and accelerating the transition to zero emission technologies.

Implementation will not impact the useful life of vehicles prior to model year 2026, but it will help ensure that emission benefits and durability of vehicles manufactured for model years 2026 through 2035 are maximized. Gasoline powered vehicles for these model years will be required to meet more stringent emission standards through testing representative of real-world operating conditions. Manufacturers of battery electric and fuel cell electric vehicles will be required to demonstrate the durability of these vehicles attesting that that these vehicles will maintain 80 percent of their certified two cycle range for their full useful life, defined as 10 years or 150,000 miles. At the end of their first useful life, batteries from mobile sources can be repurposed for use in stationary storage towers. CARB is working with stakeholders to identify additional opportunities for repurposing and recycling vehicle batteries.

CARB will continue to evaluate opportunities to reduce emissions from on-road mobile sources, as these reductions are critical to meeting air quality, climate, and community health goals. Federal actions to reduce emissions from on-road sources, particularly those in the heavy-duty sector, would complement State efforts and accelerate progress towards meeting air quality, climate, and community health goals throughout the state.

Off-Road Mobile Sources

Emissions from off-road mobile sources contribute to California's air quality challenges, accounting for around 30 percent of total NOx emissions. Measures intended to reduce emissions from four off-road mobile source categories are discussed in detail on the following pages. The Transport Refrigeration Unit Regulation aims to reduce emissions by implementing more stringent emission standards and accelerating the transition to zero-emission equipment technologies. The amendments to the Small Off-Road Engine Regulation aims to reduce emissions by accelerating the transition to zero-emission engine technologies in a sector that is well-positioned for rapid transition. The In-Use Locomotive Regulation aims to reduce emissions by improving local enforcement of idling limits and accelerating the transition to low and zero-emission engine technologies. The amendments to the Ocean-Going Vessel At-Berth Regulations aim to reduce emissions by expanding the scope of an effective, existing regulatory program for vessels at-berth in California ports. Like the measures discussed for on-road sources, these off-road mobile source control measures have been developed through an integrated planning process and are projected to lead to significant NOx emission reductions that will foster progress towards meeting air quality, climate, and community health goals in California.

Transport Refrigeration Units

Information on each of the four reasonable progress factors was obtained from publicly available documentation prepared or compiled by CARB staff for development of amendments to the TRU Airborne Toxics Control Measure (ATCM) Regulation. A more detailed impact analysis of the concepts proposed in the regulation is articulated in the SRIA. The SRIA for this proposed regulation was released for stakeholder review in May 2021. Information on each of the four factors is summarized below.

The full text of the SRIA and other rule-making documents associated with the 2021 amendments to the TRU ATCM Regulation are available online: *https://ww2.arb.ca.gov/rulemaking/2021/tru2021*.

TRU ATCM: Cost of Compliance

TRU owners will bear direct costs associated with purchasing new equipment, installing charging infrastructure, purchasing electricity, meeting reporting requirements, and registration of equipment. These direct costs will be offset by lower operating and maintenance expenses over the lifetime of the equipment, diesel fuel savings, and revenue from LCFS credits earned for using electricity as the source of power for units.

The additional amendments will impact approximately 8,800 truck TRUs and 269,000 TRUs in other categories. Truck and trailer TRUs make up approximately 83 percent of the TRU population operating in California. CARB staff estimated costs of compliance with the proposed regulations for typical businesses that own TRUs and facilities covered by the measures in this regulation. As shown in Table H-11, annual net costs vary but are expected to peak at $129.7 million in 2028.

The cost effectiveness of these measures varies because the costs, benefits, and cost savings vary annually over the implementation period. For 2028, the total costs of implementation are estimated to be $150.9 million (not accounting for cost savings). The emissions benefits for 2028 are projected to be 312 tons of NOx. Thus, for 2028, the cost per ton estimate is $483,653/ton NOx.

Consideration of costs and cost savings can yield other cost per ton estimates. The total net implementation costs for 2022 through 2034 are $1.027 billion. The NOx emissions benefit for this period is projected to be 3,515 tons. For this period, the total net cost effectiveness will be $292,176/ton of NOx. In addition to the reduction in direct emissions of NOx and PM, the amendments to the TRU ATCM regulation will have a significant cost savings in avoided adverse health outcomes and avoided social costs of carbon. For the 2022 to 2034 period, the estimated costs savings of avoided adverse health outcomes amount to $1.753 billion and the estimated avoided social costs of carbon are estimated to range from $29 million to $134 million, depending on the discount rate.

Table H-11: Total Net Costs (in Millions 2019$) of Amendments to TRU ATCM Regulations for 2022 to 2034

Year	Equipment	Equipment Maintenance	Infrastructure	Infrastructure Maintenance	Diesel Fuel	Electricity	LCFS Credit	Administrative	Total
2022	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
2023	$17.7	$0.9	$1.1	$0.0	$0.0	$0.0	$0.0	$10.8	$30.5
2024	$36.5	$0.8	$2.5	$0.2	-$1.7	$2.4	-$1.9	$4.3	$43.1
2025	$54.7	$0.4	$3.6	$0.4	-$3.8	$5.7	-$4.1	$4.3	$61.3
2026	$81.8	$0.3	$5.4	$0.6	-$5.6	$8.6	-$6.0	$11.0	$96.0
2027	$114.7	-$0.2	$6.9	$0.9	-$8.2	$13.1	-$9.0	$5.9	$124.0
2028	$118.9	-$0.3	$7.2	$1.1	-$10.3	$17.0	-$10.7	$6.7	$129.7
2029	$117.0	-$0.6	$6.7	$1.4	-$12.1	$20.8	-$12.9	$8.1	$128.5
2030	$108.6	-$1.0	$5.7	$1.5	-$13.1	$23.3	-$14.2	$7.0	$118.0
2031	$91.3	-$1.0	$4.0	$1.5	-$13.3	$24.2	-$14.1	$8.0	$100.6
2032	$67.1	-$1.0	$2.7	$1.6	-$13.6	$24.5	-$14.1	$7.5	$74.8
2033	$56.0	-$1.0	$1.5	$1.6	-$14.0	$24.9	-$14.0	$7.3	$62.2
2034	$51.5	-$1.0	$0.8	$1.6	-$14.3	$25.3	-$13.9	$8.5	$58.3
Total	$916.0	-$3.7	$48.1	$12.3	-$109.9	$189.8	-$114.9	$89.4	$1027.0

TRU ATCM: Time Necessary for Compliance

The proposed regulations will require truck TRU fleet operators to transition at least 15 percent of their fleets to zero-emission technologies each year beginning in 2023. The compliance schedule is shown in Table H-12. All truck TRUs, approximately 8,800 units, will have transitioned to zero emission technologies by 2029.

Table H-12: Compliance Schedule for Proposed Phase-In of Zero-Emission Requirements for Truck TRU Fleets

Model Year	2022	2023	2024	2025	2026	2027	2028	2029 and beyond
Percentage Requirement	0%	15%	30%	45%	60%	75%	90%	100%

The amendments to the TRU ATCM regulation will also require trailer TRUs, domestic shipping container TRUs, railcar TRUs, and TRU generator set engines to meet the 0.02 g/bp-hr PM emission standard beginning with model year 2023. Older units will be subject to meeting this requirement within seven years after the year of engine manufacture, as required under current TRU ATCM regulations.

TRU ATCM: Energy and Non-Air Quality Environmental Impacts

In alignment with the CEQA process, a detailed environmental analysis was prepared for the amendments proposed to the TRU ATCM regulation that considered a wide range of environmental impacts including energy and non-air quality impacts, as well as potential mitigation strategies for expected impacts. The draft environmental analysis was released on July 27, 2021. Implementation of the proposed regulations will require construction or modification of infrastructure. The construction or modification of infrastructure may result in environmental impacts that may include noise, changes in neighborhood aesthetics, habitat and soils disturbance, and management of hazardous materials.

Transitioning to zero-emission technologies will require an increased reliance on battery technologies. An increase in the volume of new and used batteries managed by businesses is expected to result from implementation of the proposed regulation.

The full text of the environmental analysis is available online: *https://ww3.arb.ca.gov/board/rulemaking/tru2021/appd.pdf*.

TRU ATCM: Remaining Useful Life

The operational life of TRU equipment is typically seven to ten years. The annual 15 percent phase-in compliance schedule generally aligns with the average useful life for a truck TRU. The proposed requirements will not require a significant number of accelerated purchases.

Batteries employed in zero-emission TRU technologies are anticipated to still have some useful life at the end of their TRU useful life. Opportunities to repurpose TRU batteries for a second life are expected to increase.

Small Off-Road Engines

Information on each of the four reasonable progress factors was obtained from publicly available documentation prepared or compiled by CARB staff for the development of the amendments to the Small Off-Road Engines (SORE) Regulation. A more detailed impact analysis of the concepts proposed in the regulation is articulated in the SRIA. The initial SRIA for this proposed regulation was released for stakeholder review in August 2020. A revised SRIA was released for stakeholder review on September 20, 2021.

The documents associated with rulemaking for the amendments to the SORE Regulation are available online: *https://ww2.arb.ca.gov/rulemaking/2021/sore2021*

Small Off-Road Engines: Cost of Compliance

Direct costs of the proposed amendments include new electric equipment purchases and electricity expenses. Direct costs will be offset by a lower cost of ownership over the life of equipment that is associated with reduced maintenance and fuel costs. Annual net costs for implementation of the proposed amendments are expected to peak at $736 million in 2024. Annual net savings for SORE users are expected following full implementation of the proposed amendments. Table H-13 summarizes the annual incremental costs to profession and residential SORE users expected to result from the implementation of measures in the amendments to the SORE regulation.

Table H-13: Annual Costs (in Millions 2019$) to Professional and Residential SORE Users under the Amendments to SORE Regulations Relative to the Baseline Scenario

Year	Gasoline Equipment	Electric Equipment	Maintenance	Gasoline	Electricity	Total Cost	Net Cost
2024	-$91.74	$856.21	-$11.81	-$19.63	$3.91	$860.12	$736.39
2025	-$88.62	$854.03	-$34.31	-$56.55	$10.67	$864.70	$685.22
2026	-$85.44	$853.02	-$58.40	-$96.07	$18.21	$871.23	$631.32
2027	-$82.22	$852.02	-$81.61	-$136.00	$25.81	$877.83	$578.00
2028	-$822.59	$1,504.07	-$103.16	-$178.44	$34.08	$1,538.15	$433.96
2029	-$828.20	$1,508.69	-$123.71	-$240.75	$44.62	$1,553.31	$360.65
2030	-$833.89	$1,514.50	-$142.14	-$301.28	$55.77	$1,570.27	$292.96
2031	-$839.63	$1,524.99	-$157.93	-$359.08	$65.33	$1,590.32	$233.68
2032	-$845.44	$1,535.61	-$171.68	-$412.74	$74.14	$1,609.75	$179.89
2033	-$851.31	$1,546.34	-$183.50	-$461.82	$82.04	$1,628.38	$131.75
2034	-$857.25	$1,557.19	-$193.72	-$506.52	$89.10	$1,646.29	$88.80
2035	-$863.25	$1,568.16	-$202.30	-$546.21	$95.29	$1,663.45	$51.69
2036	-$869.32	$1,579.26	-$209.44	-$580.37	$100.52	$1,679.78	$20.65
2037	-$875.46	$1,590.47	-$215.32	-$609.94	$104.98	$1,695.45	-$5.27
2038	-$881.67	$1,601.81	-$219.92	-$635.31	$108.76	$1,710.57	-$26.33
2039	-$887.95	$1,613.28	-$223.73	-$656.75	$111.92	$1,725.20	-$43.23
2040	-$894.30	$1,624.88	-$226.59	-$674.35	$114.50	$1,739.38	-$55.86
2041	-$900.72	$1,636.60	-$228.95	-$689.23	$116.67	$1,753.27	-$65.63
2042	-$907.21	$1,648.46	-$230.99	-$702.09	$118.54	$1,767.00	-$73.29
2043	-$913.77	$1,660.44	$232.76	-$713.09	$120.14	$1,780.58	-$79.04
Total	-$14,219.99	$28,630.03	-$3,251.97	-$8,576.22	$1,495.00	$30,125.03	$4,076.85

The combined NOx and reactive organic gases (ROG) emissions benefit will scale up with the transition to zero-emission equipment. In addition to the reduction in direct emissions of NOx and ROG, the proposed regulation will have a significant cost savings in avoided adverse health outcomes and avoided social costs of carbon. For the 2024 to 2043 period, the estimated costs savings of avoided adverse health outcomes amount to $8.8 billion and the estimated avoided social costs of carbon are estimated to range from $339 million to $1.4 billion, depending on the discount rate.

The annual cost effectiveness of the amendments is variable over the course of the implementation period. When only NOx emission benefits are considered, the estimated total cost per ton of implementation in 2028 is $957,752/ton of NOx. As discussed earlier, the emissions benefits go beyond NOx and cost savings associated operational changes and avoided adverse health outcomes are expected.

Small Off-Road Engines: Time Necessary for Compliance

Emission standards for small off-road engines will be set to zero beginning with MY 2024, except for standards applicable to portable generators. More stringent emission standards for portable generators will be implemented for MY 2024 through 2027. Emission standards for small portable generators will be set to zero beginning in MY 2028.

Small Off-Road Engines: Energy and Non-Air Quality Environmental Impacts

The amendments to the SORE regulation are subject to CEQA review. Environmental impacts of measures in the amendments were considered during this review process. In alignment with the CEQA process, a detailed supplemental environmental analysis was prepared that considered a wide range of environmental impacts including energy and non-air quality impacts, as well as potential mitigation strategies for expected impacts. The initial environmental analysis was completed in 2017 as part of the consideration of all measures in the 2016 State SIP Strategy. This initial environmental analysis was released for public review on March 10, 2017.

Further consideration of environmental impacts was completed during the development of the draft amendments to the SORE regulation. This consideration is included in Chapter V of the ISOR for these amendments that was released for public review on October 12, 2021. Implementation of the proposed amendments and the associated transition to zero-emission technologies will require an increased reliance on battery technologies. An increase in management of new and used batteries is expected to result from implementation of the proposed regulation.

Full text of the environmental analyses completed for the measures in the SORE amendments is available online: *https://ww2.arb.ca.gov/rulemaking/2021/sore2021*

Small Off-Road Engines: Remaining Useful Life

The typical lifetime of residential equipment with small-off road engines is ten years, whereas the typical lifetime for commercial equipment is five years. The timelines associated with the proposed amendments to the SORE regulations will allow for an efficient transition to zero-emission equipment in the commercial and residential sectors.

Batteries used in zero-emission equipment tend to outlive the equipment, so there may be some cost savings when new equipment is purchased because batteries from the old equipment may be used in the new equipment from common product lines.

Locomotives

The information on each of the four reasonable progress factors was obtained from publicly available documentation prepared or compiled by CARB staff for the development of the In-Use Locomotive Regulation. A comprehensive impact analysis of the concepts in the regulation will be provided in the SRIA that is expected to be released for stakeholder review in April 2022. More information about CARB's efforts to reduce rail emissions, including draft regulatory language for the In-Use Locomotive Regulation and preliminary cost estimates, is available online: *https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california*

In-Use Locomotive Regulation: Cost of Compliance

Staff assume that locomotive operators will use spending account funds to purchase the cleanest available locomotives and funds will not be held unnecessarily. The costs to invest in cleaner locomotive fleets will be offset by reduced deposit requirements that will follow the reduction in locomotive fleet emissions.

The administrative costs associated with the spending account reporting requirements will vary by the fleet size. The CARB registration fee is expected to be $175 to $225 per locomotive. Additional personnel will be needed for the rail operators to fulfill the reporting requirements. For Class I railroads, one to two personnel will be needed each year, whereas for Class III, industrial, and passenger rail operators, 0.1 to 0.3 full time personnel will be needed. The expected administrative costs associated with the proposed regulation are summarized in Table H-14.

Table H-14: Administrative Personnel Costs

Rail Operator Category	Full-Time Equivalent Personnel	Annual Cost Range (2019$)
Class I	1 to 2	150,715 to 301,430
Class III	0.2 to 0.3	30,143 to 45,215
Industrial	0.1 to 0.2	15,072 to 30,143
Passenger	0.2 to 0.3	30,143 to 45,215

Installation of new hardware or software on locomotives is not required to comply with the reporting requirements. Instead, locomotive operators may need to establish or redesign reporting operation tracking protocols. CARB staff are still in the process of developing spending account deposit estimates based on emission factors for different engine tiers. Estimates of the annual deposits for locomotive railroad operators will be available when the SRIA is released for stakeholder review. Deposit funds, while considered an up-front cost to operators, will be used solely by operators to improve their locomotive fleets. Lower maintenance and fuel costs are expected following fleet improvements. The cumulative impacts of these costs will be included in the analysis reported in the SRIA.

Locomotives that have reached the end of their useful life will be banned from operating in California. As demand for services is expected to continue to increase, operators will replace locomotives retired from service in California with new locomotives. As shown in Table H-15, the cost to purchase a new locomotive varies by type.

Table H-15: Cost Estimates for Locomotives

Transition Type	Locomotive Description	Cost Range (2019$)
Purchase New	Tier 4 Line Haul	$2,700,000 to 3,300,000 per locomotive
Purchase New	Beyond Tier 4 Line Haul (Hydrogen)	$4,000,000 to 4,250,000 per locomotive
Purchase New	Beyond Tier 4 Line Haul (Battery Electric)	$4,500,000 to 8,000,000 per locomotive
Purchase New	Tier 4 Switcher	$2,150,000 to 2,700,000 per locomotive
Purchase New	Beyond Tier 4 Switcher (Hydrogen)	$2,750,000 to 3,800,000 per locomotive
Purchase New	Beyond Tier 4 Switcher (Battery Electric)	$3,500,000 to 5,000,000 per locomotive
Repower	Switcher with Pre-Tier 0, 1, 2, or 3 genset to Tier 4	$2,000,000 to 2,500,000 per locomotive
Purchase New	Tier 4 Passenger	$7,165,000 to 7,500,000 per locomotive
Purchase New	Hydrogen Powered Passenger (beyond Tier 4)	$10,000,000 to 16,000,000 per locomotive
Purchase New	Beyond Tier 4 Passenger (Battery Electric)	$10,000,000 to 12,000,000 per locomotive
Retrofit	Tier 2 Passenger to Beyond Tier 4 (Hydrogen)	$6,000,000 to 8,000,000 per conversion
Retrofit to Tier 4	Passenger with Tier 2 engine	$560,000 to 570,000 per locomotive conversion

The cost for a new Tier 4 line haul locomotive ranges from $2.7 to $3.3 million. The commercial cost for line haul locomotives with beyond Tier 4 engine technologies is expected to range from $4 to $8 million. The cost to purchase a new Tier 4 switcher locomotive ranges from $2.15 to $2.7 million, whereas switcher locomotives with beyond Tier 4 engine technologies are expected to cost $2.75 to $5 million. Passenger locomotives with

Tier 4 engines cost $7.16 to $7.5 million and the commercial cost for passenger locomotives with beyond Tier 4 engines is expected to be $10 to $16 million.

Operator spending accounts will be used to cover or offset the purchase cost for new locomotives. State grant and incentive programs are also available to offset the direct cost of new locomotive purchases. Reduced maintenance and fuel costs are expected to follow the replacement of old locomotives with new locomotives in the operator's fleet. Installation of upgraded or new infrastructure is expected with the increase in more efficient locomotives.

No new costs for operators are anticipated to result from California's adoption of the U.S. EPA idling limit as the idling limit is already a federal requirement. Operators out of compliance with idling limits will be required to make the necessary operational changes to ensure that the locomotive engine is powered down within 30 minutes of becoming stationary. State and local agencies currently work as liaisons between complainants, operators, and U.S. EPA to respond to idling complaints. Resources for enforcement will be in-kind and liaison work will be more efficient because of the added State enforcement authority.

In-Use Locomotive Regulation: Time Necessary for Compliance

Implementation of the spending account concept is proposed to begin in 2023. The deposits made by operators in 2023 will be based on operations in 2022.

The implementation of the useful life limit concept is expected to begin in 2030. Beginning in 2030, any locomotive newly manufactured in 2007 or earlier will be banned from operating in California. Each subsequent year, the ban applies to locomotives manufactured more than 23 calendar years prior.

Implementation of the idling limits associated with this regulation is expected by 2024. Personnel from the state agencies, local agencies, and locomotive operators are already familiar with federal rules. The idling limits that operators would be subject under the proposed regulation do not change substantively from the existing federal idling limits. The ability of CARB staff to enforce the idling limit will be the primary change resulting from this measure in the proposed regulation.

In-Use Locomotive Regulation: Energy & Non-Air Quality Environmental Impacts

The proposed regulation is subject to CEQA review. Environmental impacts of each concept of the proposed regulation are considered during this review process. No major environmental impacts are expected to result from implementation of a locomotive spending account measure.

The energy and non-air quality impacts of compliance with the useful life limit include disposal of old engines, reduced fuel consumption, and potentially reduced amounts of hazardous waste disposal associated with diesel engine maintenance as fleets transition to beyond Tier 4 technologies.

The idling limits in the proposed regulation are consistent with existing federal limits. With exception of the air quality benefits, no major environmental impacts are expected to result from implementation of a locomotive idling limit measure.

More information about the CEQA review for the proposed regulation is available online: *https://ceqanet.opr.ca.gov/2020100517/2*.

In-Use Locomotive Regulation: Remaining Useful Life

The spending account concept is compliment by the useful life limit concept in the proposed regulation. Beginning in 2030, locomotives older than 23 years will be banned from operating in California unless they are equipped with zero emission technologies. This factor is not applicable to the idling concept as no new control devices are proposed, simply improved enforcement pathways. Additional resources about rail in California, CARB agreements with railroad operators, and the proposed In-Use Locomotive Regulation are available online. Weblinks are provided below.

California State Rail Plan:
https://dot.ca.gov/programs/rail-and-mass-transportation/california-state-rail-plan

1998 Locomotive NOx Fleet Average Emissions Agreement:
https://ww2.arb.ca.gov/resources/documents/rail-emission-reduction-agreements

2005 ARB/Railroad Statewide Agreement:
https://ww2.arb.ca.gov/sites/default/files/2020-06/2005%20MOU%20Remediated%2003102020.pdf

2017 Petition to US EPA:
https://ww2.arb.ca.gov/resources/documents/carb-petitions-us-epa-strengthen-locomotive-emission-standards

Preliminary Cost Document for the In-Use Locomotive Regulation
https://ww2.arb.ca.gov/sites/default/files/2021-03/3.16.21%20Locomotive%20Reg%20-%20Preliminary%20Cost%20Document_Final.pdf

Draft In Use Locomotive Regulation
https://ww2.arb.ca.gov/sites/default/files/2021-03/Draft%20Regulatory%20Language%2003.16.21.pdf

Ocean-Going Vessels

The information on each of the four reasonable progress factors considered was obtained from publicly available documentation prepared or compiled by CARB staff for the proposed amendments to the at-berth regulation. A comprehensive impact analysis of the concepts proposed in the amendments is provided in the SRIA, as well as the assumptions, inputs, and data sources for the analysis summarized below. The SRIA for the proposed amendments to the at-berth regulation was released for stakeholder review in August 2019.

The full text of the SRIA and other rule-making documents associated with the amendments to the OGV At-Berth Regulation are online: *https://ww2.arb.ca.gov/rulemaking/2019/ogvatberth2019*.

OGV At-Berth Regulation Amendments: Cost of Compliance

The total cost of the OGV At-Berth Regulation is estimated to be $2.23 billion. This cumulative cost includes anticipated annualized expenses for port authorities, terminal operators, vessel operators, and government agencies including CARB. Costs associated with the proposed amendments include direct costs for construction of infrastructure for shore power units, emission capture and control units, administrative operations, permitting, energy, and maintenance costs. The total costs of the proposed regulation by vessel type are shown in Table H-16.

Table H-16: Total Costs of the Proposed Regulation by Vessel Type

Year	Container/Reefer	Cruise	Ro-Ro	Tanker	Bulk/General Cargo	Total
2020	$8,255,000	$13,706,000	$138,000	$15,107,000	$0	$37,206,000
2021	$15,639,000	$15,504,000	$498,000	$16,403,000	$209,000	$48,253,000
2022	$15,926,000	$15,990,000	$396,000	$43,494,000	$209,000	$76,014,000
2023	$16,172,000	$16,652,000	$435,000	$43,496,000	$209,000	$76,964,000
2024	$16,745,000	$17,220,000	$1,499,000	$87,350,000	$209,000	$132,022,000
2025	$17,448,000	$17,836,000	$16,053,000	$87,719,000	$209,000	$139,264,000
2026	$18,232,000	$18,457,000	$16,519,000	$186,066,000	$209,000	$239,482,000
2027	$18,740,000	$19,107,000	$17,027,000	$194,806,000	$209,000	$249,888,000
2028	$19,197,000	$19,761,000	$17,410,000	$196,575,000	$209,000	$253,152,000
2029	$19,694,000	$20,439,000	$17,801,000	$212,182,000	$209,000	$270,325,000
2030	$20,233,000	$21,149,000	$18,202,000	$214,444,000	$209,000	$274,235,000
2031	$20,890,000	$21,863,000	$18,612,000	$216,935,000	$209,000	$278,509,000
2032	$21,833,000	$22,614,000	$18,612,000	$219,392,000	$209,000	$283,095,000
Total	$229,004,000	$240,298,000	$19,047,000	$1,733,969,000	$2,503,000	$2,349,410,000

The estimated NOx reduction expected from implementation of the proposed measures is 20,000 tons between 2021 and 2032. Taking the estimated costs and emissions benefits into considered, the estimated cost effectiveness of this proposed regulation is around $117,000 per ton NOx. The implementation costs will be offset by reduced fuel consumption. Costs will not be borne by a single entity, rather they will be distributed over individual units of freight. Table H-17 summarizes the estimated costs over individual freight units for the affected vessel types.

Table H-17: Estimated Incremental Cost of Compliance by Vessel Type

Vessel Type	Annualized Cost in 2030	Total Units in 2030	Unit Costs of Compliance
Container/Reefer	$20,233,000	15,590,200	$1.30 per TEU
Cruise	$21,149,000	4,031,800	$5.25 per passenger
Ro-Ro	$18,244,000	2,437,300	$7.49 per automobile
Tanker	$214,444,000	27,156,860,144	Less than $0.008 per gallon of finished product

In addition to the reduction in direct emissions of NOx, the proposed regulation will have a significant cost savings in avoided adverse health outcomes. For the 2021 to 2032 period, the estimated cost savings of avoided adverse health outcomes amount to $2.3 billion.

OGV At-Berth Regulation Amendments: Time Necessary for Compliance

Implementation of the requirements in the amended regulation will take effect beginning in 2023 with full implementation by 2027. In 2023, the requirements will apply to container vessels, reefer vessels, and cruise vessels in all covered ports. In 2025, ro-ro vessels at all covered parts will be required to comply with the regulation. Requirements for tanker vessels at the Ports of Los Angeles and Long Beach will take effect in 2025 and in 2027 at the remaining ports. The scaled implementation will allow for the construction of necessary infrastructure at affected ports and terminals.

OGV At-Berth Regulation Amendments: Energy and Non-Air Quality Environmental Impacts

In alignment with the CEQA process, a detailed environmental analysis was prepared for the proposed amendments that considered a wide range of environmental impacts including energy and non-air quality impacts, as well as potential mitigation strategies for expected impacts. The draft environmental analysis was released in October 2019. Following consideration of public comments on the draft analysis, a final analysis was released in August 2020.

Implementation of the proposed regulation will require construction or modification of infrastructure, which may result in impacts that include noise, changes in landscape aesthetics, habitat and soils disturbance, aquatic acoustical disturbance, and management of hazardous materials. Implementation of the proposed regulation may also lead to an increase in lithium and platinum mining to support increased demands for fuel cells. An increase in recycling, refurbishment, and disposal needs may also result from the implementation of the proposed regulation.

The full text of the final environmental analysis is available online: *https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2019/ogvatberth2019/finalea.pdf*.

More information about the CEQA review for the proposed regulation is available online: *https://ww2.arb.ca.gov/rulemaking/2019/ogvatberth2019*.

OGV At-Berth Regulation Amendments: Remaining Useful Life

The useful life of an OGV is approximately 25 years. The proposed amendments would not require replacement of vessels, but rather potential modification of the auxiliary power system. For vessels opting to connect to shore power, modifications will need to be made to the vessel that will allow for the connection to shore power systems. For vessels opting to meet the requirements of the regulation through aftertreatment, modification of the vessels to allow for connection to barge or shore-based capture and control systems will be necessary.

Additional resources about OGVs in California, local programs targeting OGV emissions, and the proposed amendments to CARB's OGV At-Berth regulations are available online. Weblinks to these resources are provided below.

CARB Contracted Study:
https://ww2.arb.ca.gov/sites/default/files/classic/ports/marinevess/vsr/docs/vsr.pdf

USCG Port Access Route Study:
https://www.federalregister.gov/documents/2011/11/01/2011-28270/port-access-route-study-in-the-approaches-to-los-angeles-long-beach-and-in-the-santa-barbara-channel

Port of Los Angeles Environmental Ship Index Program:
https://www.portoflosangeles.org/environment/air-quality/environmental-ship-index

Port of Long Beach Green Flag Program:
https://polb.com/business/incentives/#green-flag-program

Protecting Blue Whales and Blue Skies VSR Program:
https://www.ourair.org/air-pollution-marine-shipping/

Stationary Source Emission Controls

Collins Pine Company

Selective non-catalytic reduction was identified as a potentially feasible NOx control option for consideration.

SNCR: Cost of Compliance

The cost estimates provided by the consulting firm Maul Foster and Alongi (MFA) were developed using industry knowledge and the U.S. EPA Cost Control Manual. The facility operator will bear the costs associated with installation of an SNCR system. Direct costs include installation labor and materials for the control system and reagent storage, reagent demand, power demand, water demand, and fuel demand. The total capital investment estimated for an SNCR system is $1.97 million, with total annual costs estimated to be $359,561. Considering a conservative control efficiency of 25 percent and annual emissions of 129 tpy NOx, the estimated annual cost effectiveness of an SNCR system would be $11,149 per ton of NOx.

The annual emissions reported to the NEI were based on source testing. Review of continuous emissions monitoring system (CEMS) data provided by the facility operator indicate that actual emissions are lower than those estimated from source testing data. CEMS data indicate that actual annual NOx emissions in 2017 were 58 tpy. Considering these data, the estimated annual cost effectiveness would be $24,670 per ton of NOx.

SNCR: Time Necessary for Compliance

Installation of an SNCR system would involve permitting, equipment procurement, construction, startup, and testing. Under typical circumstances, implementation would be expected to take 24 to 36 months to complete. However, the facility is in an area directly impacted by the Dixie Fire.

The Dixie Fire began on July 13, 2021 and is the largest single fire in California history to date. A federal disaster was declared in response to the Dixie Fire on July 20, 2021. The fire burned nearly one million acres including portions of Lassen Volcanic National Park and adjacent wilderness areas. Resultant damage to the local infrastructure and economy will likely extend the amount of time needed for implementation.

SNCR: Energy and Non-Air Quality Environmental Impacts

Installation of an SNCR system will result in increased energy demands associated with operation of injection ports and heating of reagent storage tanks. Increased fuel demands for boiler operations are also expected to mitigate increased moisture loads caused by urea injection. Operation of an SNCR system will also lead to increased water demands. Drought conditions persist in Plumas County where the facility is located. Exceptional drought conditions are present in the western portion of the county and extreme drought conditions are present in the eastern portion of the county.

Other environmental impacts are upstream processes to produce urea including extraction and processing of natural gas as well as participation in community fuel reduction efforts. The facility accepts forest waste and yard waste materials from the public at no cost. This waste diversion program plays a role in reducing fire risk and mitigating impacts from uncontrolled burning of waste materials on private residential properties.

Half of the Collins Pine's timber lands were burned by the Dixie Fire, resulting in an unprecedented number of dead and dying trees. Harvest and processing of these trees needs to occur within two years to avoid rot and insect infestation. Removal of these trees from the landscape is needed to facilitate replanting and restoration of a resilient, productive forest system.

SNCR: Remaining Useful Life

Based on industry knowledge, the emission unit will likely outlast the proposed control system. The annualized control costs are based on the useful life of SNCR system rather than the boiler.

Analysis Provided by MFA for Collins Pine Company

REGIONAL HAZE FOUR FACTOR ANALYSIS

COLLINS PINE COMPANY—CHESTER FACILITY

Prepared for
COLLINS PINE COMPANY
CHESTER FACILITY
September 16, 2021
Project No. 1780.03.01

Prepared by
Maul Foster & Alongi, Inc.
6 Centerpointe Drive, Suite 360, Lake Oswego, OR 97035

MAUL
FOSTER
ALONGI

CONTENTS

ACRONYMS AND ABBREVIATIONS

$/ton	dollars per ton of pollutant controlled
°F	degrees Fahrenheit
Analysis	Regional Haze Four-Factor Analysis
CARB	California Air Resources Board
Collins	Collins Pine Company
Control Cost Manual	EPA Air Pollution Control Cost Manual
DESP	dry electrostatic precipitator
EPA	U.S. Environmental Protection Agency
facility	wood products manufacturing and cogeneration facility located at 500 Main Street, Chester, California 96020
Federal Guidance Document	Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
FGR	Flue gas recirculation
MFA	Maul Foster & Alongi, Inc.
NH_3	ammonia
NO	nitric oxide
NO_X	oxides of nitrogen
PSD	Prevention of Significant Deterioration
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction

1 INTRODUCTION

The California Air Resources Board (CARB) requested that Collins Pine Company (Collins) conduct a Regional Haze Four Factor Analysis (Analysis) for their wood products manufacturing and cogeneration facility in Chester, California. The Analysis estimates the cost associated with reducing visibility-impairing pollutants, specifically oxides of nitrogen (NO_X). The four factors that must be considered when assessing the states' reasonable progress, which are codified in Section 169A(g)(1) of the Clean Air Act, are:

(1) The cost of control,

(2) The time required to achieve control,

(3) The energy and non-air-quality environmental impacts of control, and

(4) The remaining useful life of the existing source of emissions.

The development of this Analysis has relied on the following guidance documents:

1) U.S. Environmental Protection Agency (EPA) Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003 (Federal Guidance Document).

2) EPA Air Pollution Control Cost Manual, which is maintained online and includes separate chapters for different control devices as well as several electronic calculation spreadsheets that can be used to estimate the cost of control for several control devices (Control Cost Manual).

1.1 Facility Description

Collins owns and operates a wood products manufacturing and cogeneration facility located at 500 Main Street, Chester, California 96020 (the facility). The facility underwent Prevention of Significant Deterioration (PSD) review for NO_X, CO and PM when the new powerhouse was installed, and EPA Region 9 amended that PSD permit as recently as 2017. The facility is currently operating under the Northern Sierra Air Quality Management District Title V Operating Permit No. NSAQMD-CP-01, issued May 14, 2014, as well as the EPA Region 9 PSD permit. The facility is a major stationary source of criteria pollutants.

The facility is located south of the Cascade Range and is approximately 13 kilometers southeast of the Caribou Wilderness Area, the nearest Class I Area.

1.2 Process Description

The existing lumber and sawmill operations debark whole logs and cut them to size with a variety of saws. The rough-cut material is either sold as-is or is further processed by planing and/or kiln drying.

The facility produces and sells both green and dry lumber. Residual wood materials are generated on-site by various processes, including from debarking, sawing, and planing operations. The residuals are collected by a cyclone or one of the target boxes, and then stored for use in the facility's hogged fuel cogeneration boiler.

A portion of the rough-cut lumber is sent to the lumber dry kilns to remove excess moisture. The dried boards are then finished at the planer and sold as kiln dried lumber. All kilns are indirectly heated with steam produced by the Keeler cogeneration boiler. Steam energy produced by the Keeler cogeneration boiler is used to generate electricity to power the sawmill operations and no longer supplies energy to the electrical grid.

2 APPLICABLE EMISSION SOURCES

Collins retained Maul Foster & Alongi, Inc. (MFA) to assist the facility with completing this Analysis. As requested by CARB, the Analysis is specific to NO_X emissions from the Keeler cogeneration boiler based on calendar year 2017 emissions, as California's screening process was based on 2017 emissions data.

The following sections present a description of the emission unit, the emissions information rate, and pertinent exhaust parameters that will be used in the Analysis.

2.1 Keeler Cogeneration Boiler

The Keeler cogeneration boiler combusts clean lumber, clean hogged fuel, wood fuel, yard wastes or mixtures thereof to produce steam that is used for cogeneration (i.e., steam generates electricity and heat for processes). The boiler combusts an extremely limited amount of no. 2 diesel for start-up only. The Keeler boiler has a design heat input capacity when firing wood fuels (hogged wood, bark, chips) of 242.3 million British thermal units per hour, and can produce a maximum of 140,000 lb steam/hr. At the present time, the facility does not supply power to the electrical grid, and the 12 MW turbine is no longer in service as of December 2020.

The boiler uses multiclones followed by a dry electrostatic precipitator (DESP) to control particulate matter. Collins maintains and operates a continuous monitoring system to measure NO_X, carbon monoxide, and carbon dioxide concentrations from the boiler stack.

A summary of the selected emission unit and associated NO_X emission rate to be evaluated in the Analysis is presented in Table 2-1 (attached).

3 REGIONAL HAZE FOUR-FACTOR ANALYSIS METHODOLOGY

This Analysis has been conducted consistent with the Federal Guidance Document, which outlines six steps to be taken when addressing the four statutorily required factors included in the Analysis. These steps are described in the following sections.

3.1 Step 1: Determine Emission Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

Section 2 details the selection of emission units and emission rates to be used in the Analysis. Emission rates from calendar year 2017 were obtained from the National Emissions Inventory and are assumed to represent the most reasonable estimate of actual emissions in 2028.

3.3 Step 3: Characterizing Cost of Compliance (Statutory Factor 1)

Once the sources, emissions, and control methods have all been selected, the cost of compliance is estimated. The cost of compliance, expressed in units of dollars per ton of pollutant controlled ($/ton), describes the cost associated with the reduction of visibility-impairing pollutants. Specific costs associated with operation, maintenance, and utilities at the facility are presented in Table 2-1 (attached).

The Federal Guidance Document recommends that cost estimates follow the methods and recommendations in the Control Cost Manual. This includes the recently updated calculation spreadsheets that implement the revised chapters of the Control Cost Manual. The Federal Guidance Document recommends using the generic cost estimation algorithms detailed in the Control Cost Manual in cases where site-specific cost estimates are not available.

Additionally, the Federal Guidance Document recommends using the Control Cost Manual in order to effect an “apples-to-apples” comparison of costs across different sources and industries.

3.4 Step 4: Characterizing Time Necessary for Compliance (Statutory Factor 2)

Characterizing the time necessary for compliance requires an understanding of construction timelines, which include planning, construction, shake-down and, finally, operation. The time that is needed to complete these tasks must be reasonable, and does not have to be "as expeditiously as practicable…" as is required by the Best Available Retrofit Technology regulations.

3.5 Step 5: Characterizing Energy and Non-air Environmental Impacts (Statutory Factor 3)

Both the energy impacts and the non-air environmental impacts are estimated for the control measures that were costed in Step 3. These include estimating the energy required for a given control method, but do not include the indirect impacts of a particular control method, as stated in the Federal Guidance Document.

The non-air environmental impacts can include estimates of waste generated from a control measure and its disposal. For example, nearby water bodies could be impacted by the disposed-of waste, constituting a non-air environmental impact.

3.6 Step 6: Characterize the Remaining Useful Life of Source (Statutory Factor 4)

The Federal Guidance Document highlights several factors to consider when characterizing the remaining useful life of the source. The primary issue is that often the useful life of the control measure is shorter than the remaining useful life of the source. However, it is also possible that a source is slated to be shut down well before a control device would be cost effective.

4 NO_X ANALYSIS

The following Analysis for NO_X emissions follows the six steps previously described in Section 3.

4.1 Step 1—Determine NO_X Control Measures for Consideration

4.1.1 Good Combustion Practices

Good combustion practices can lower the emission of NO_X by using operational and design elements that optimize the amount and distribution of excess air in the combustion zone. Good combustion practices can be implemented by operating the boiler according to the manufacturer's recommendation, periodic inspections and maintenance, and periodic tuning of boilers to maintain excess air at optimum levels. Good combustion practices are currently used for the Keeler boiler and were the basis for the NO_X Best Available Control Technology (BACT) limits in the PSD permit. Additionally, Collins will have the Keeler boiler tuned every two years to maintain optimum performance.

According to NSPS Part 60 subpart Db Section 60.44b(d), the NO_X emission rate shall not exceed 0.3 lb/MMBtu. The current permit limits NO_X to 55 lb/hr, which is equivalent to 0.22 lb/MMBtu. The

2020 performance test demonstrated an emission rate of 0.189 lb/MMBtu. Good combustion practices used for the Keeler boiler have resulted in emission rates well below the federally New Source Performance Standard applicable to new and modified biomass boilers of this size and are considered technically feasible for this Analysis.

4.1.2 Flue Gas Recirculation

Flue gas recirculation (FGR) requires recirculating a portion of exhaust gases back into the combustion zone to lower the flame temperature. The reduction in peak flame temperature reduces the formation of thermal NO_X.

FGR has demonstrated reduction in NO_X when combustion temperatures are between 2,000°F and 2,500°F, however, minimal thermal NO_X is formed in hogged fuel boilers due to the high moisture content of the wood. The moisture content of the fuel at Collins ranges from approximately 45 percent in summer to 55 percent in the fall, winter, and spring months, resulting in flame temperatures below 1,750°F. NO_X reduction may be as low as 15 to 20 percent in the summer while burning fuel with a moisture content as low as 45 percent. In the spring, late fall and winter, the higher fuel moisture content further limits the effectiveness of FGR as a NO_X control strategy.

FGR technology in boilers requires the installation of additional ductwork, combustion air fans, and structures to recirculate the flue gases from the DESP exhaust stack back into the combustion zone. Due to the extensive structural changes and addition of new equipment, FGR is difficult to retrofit on existing boilers. Based on the challenges with retrofitting the hogged fuel boiler and the minimal expected performance of FGR technology, FGR for the hogged fuel boiler was excluded from further consideration in the analysis.

4.1.3 Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) systems have been widely employed for biomass combustion systems. SNCR utilizes the combustion chamber as the control device reactor. SNCR systems rely on the reaction of ammonia (NH_3) and nitric oxide (NO) at temperatures of 1,550°F to 1,950°F to produce molecular nitrogen and water, common atmospheric constituents, in the following reaction:

$$4NO+4NH_3+O_2 \rightarrow 4N_2+6H_2O$$

In the SNCR process, the ammonia or urea is injected into the combustion chamber, where the combustion gas temperature is in the proper range for the reaction. The reduction reaction between ammonia and NO is favored over other chemical reactions at the appropriate combustion temperatures and is, therefore, a selective reaction.

One disadvantage of SNCR, and any control systems that rely on the ammonia and NO reaction (including applications where urea is injected since the urea is first converted to chemically reactive ammonia in the flue gas prior to the NO reaction), is that excess ammonia (commonly referred to as "ammonia slip") must be injected to achieve control. Ammonia is a contributor to atmospheric formation of particulate that can contribute to regional haze. Therefore, the need to reduce NO_X

emissions must be balanced with the potential harm to regional visibility levels as the result of ammonia slip.

Ammonia as an SNCR injection solution presents additional safety concerns regarding its transfer and storage. Aqueous ammonia solutions at the necessary concentration and volumes required for SNCR systems can present many hazards to workers and may subject a facility to additional OSHA, Process Safety Management and Accidental Release Prevention Program requirements. Therefore, urea solutions are selected as the injection solution for evaluation of SNCR control systems. While urea injection can result in a decrease in combustion efficiency and slightly lower NO_X control efficiency, it is preferred due to ammonia solution safety hazards.

Collins consulted Sheldon Schultz, the former General Manager of Yanke Energy for his professional judgement regarding the applicability of SNCR technology for the Keeler boiler. He is familiar with the facility and has previously performed testing on the Keeler boiler by monitoring flue gas emissions and oxygen levels at the boiler furnace outlet. Mr. Schultz stated that although the temperature in the upper furnace is high enough for the reduction reaction using ammonia, the temperature is not adequate for application using urea reagent. Please see Mr. Schultz's memo in Appendix A for more detailed information.

Mr. Schultz also stated that the Keeler boiler is somewhat unique due to its large grate surface and short furnace height as compared to typical installations. Additionally, the boiler has radiant super heaters in the top of the short furnace. The residence time for the SNCR reaction is the average time it takes the flue gas to pass through this furnace volume. A residence time of 0.3 to 0.5 seconds is required for effective control. The required time is not available in the Keeler boiler, as the flue gas velocity in the upper furnace is 19 feet per second and distance between the top of the flame and the beginning of the bull nose where the flue gas velocity increases is about 4 feet, resulting in a residence time of approximately 0.2 seconds.

The short residence time would require an excessive amount of reducing agent to achieve any significant NO_X control. The increased reagent application and high heat absorption in the upper furnace from the radiant super heater would rapidly cool the flue gas resulting in high levels of ammonia slip. For this reason, we expect that the levels of ammonia slip would exceed the standard 20 ppm limit.

Additionally, in applications where an SNCR is retrofitted to an existing combustion chamber (i.e., an existing boiler), substantial care must be used when selecting injection locations. This is because proper mixing of the injected urea cannot always be achieved in a retrofit, possibly because of limited space inside the boiler itself. For this reason, in retrofit applications it is common to achieve control efficiencies of 20 to 25 percent. Due to the limited space within the Keeler boiler, actual performance may be lower.

No computational fluid dynamics modeling was conducted to determine that an SNCR would in fact work for this boiler. Mr. Schultz estimated a 20 to 25 percent control efficiency at a 25 ppm slip limit. Without engineering analyses, the level of control efficiency cannot be guaranteed, and performance may be lower than the 20 to 25 percent range.

4.1.4 Selective Catalytic Reduction and Hybrid Systems

Unlike SNCR, selective catalytic reduction (SCR) reduces NO_X emissions with ammonia in the presence of a catalyst. The major advantages of SCR technology are the higher control efficiency (70% to 90%) and the lower temperatures at which the reaction can take place (480°F to 800°F[1], depending on the catalyst selected). The optimal temperature range for catalytic reduction is 650°F to 850°F[2]. In an SNCR/SCR hybrid system, ammonia or urea is injected into the combustion chamber to provide the initial reaction with NO_X emissions, followed by a catalytic (SCR) section that further enhances the reduction of NO_X emissions. The primary reactions that take place in the presence of the catalyst are:

$4NO+4NH_3+ O_2 \rightarrow 4N_2+ 6H_2O$

$2NO_2+4NH_3+ O_2 \rightarrow 3N_2+ 6H_2O$

$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$

SCR is widely used for combustion processes, such as those using natural gas turbines, where the type of fuel produces a relatively clean combustion gas. SCR is not widely used with wood-fired combustion units because of the amount of particulate that is generated by the combustion of wood. If not removed completely, the particulate can cause binding, plugging, and fouling in the catalyst and can coat the catalyst, reducing the surface area for reaction. Another challenge with wood-fired combustion is the presence of alkali metals such as sodium and potassium, which are commonly found in wood but not in fossil fuels. Sodium and potassium will poison catalysts, and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorus and arsenic.

In order to prevent the plugging, blinding, and/or poisoning of the SCR catalyst, it is necessary to first remove particulate from the exhaust gases. It is not considered technically feasible to place an SCR unit upstream of the particulate control device in a wood-fired boiler application due to the potential for decreasing the useful life of the catalyst and decreasing the control efficiency, which can happen relatively quickly. In addition to catalyst deactivation via poisoning from contaminants present in the exhaust gas, ash from wood-fired boiler exhaust is extremely abrasive and can further damage catalyst by "sandblasting" the active pore sites of the catalyst, resulting in a decrease of the number of sites available for NO_X reduction.

Use of SCR on a wood-fired boiler application requires a high temperature particulate control device so that the downstream temperature is still in the range of 480°F to 800°F, which is necessary for the reduction of NOx in the presence of the catalyst. The SCR unit may, in certain circumstances, be located downstream of the particulate controls, after most of the ash and contaminants have been removed from the exhaust. This SCR configuration requires that temperatures downstream of the

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[1] OAQPS 7th Edition. June 2019. *Chapter 2 Selective Catalytic Reduction*. https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (Section 2.2.2).

[2] OAQPS 7th Edition. June 2019. *Chapter 2 Selective Catalytic Reduction*. https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (Figure 2.2).

particulate controls are still within the effective temperature range for NO_X reduction by catalytic reaction.

The Keeler Boiler is equipped with a DESP for final emissions control. The exhaust gas temperature at the DESP exhaust is 417°F. This temperature is below the typical SCR operating range and is well below the range optimal for catalytic reduction (650°F to 850°F). Additionally, as no control devices are 100% effective, particulate matter in the form of fly ash is still emitted. Known catalyst poisons, including arsenic, phosphorus, potassium and sodium, are present in elevated concentrations in wood combustion ashes. These contaminants are present in the treated exhaust gases (i.e., post- DESP control) and therefore can potentially deactivate SCR catalyst and render the NO_X control system ineffective.

Because of the likelihood of catalyst deactivation through particulate plugging and catalyst poisoning, and exhaust gas temperature well out of typical SCR operating range, SCR and SNCR/SCR hybrid systems are considered to be technically infeasible for control of NO_X emissions from wood-fired combustion units.

4.1.5 Low NO_X Burner

Low NO_X burners are a viable technology for a number of fuels, including sanderdust and natural gas. Low NO_X burner technology is used to moderate and control, via a staged process, the fuel and air mixing rate in the combustion zone. This modified mixing rate reduces the oxygen available for thermal NO_X formation in critical NO_X formation zones, and/or decreases the amount of fuel burned at peak flame temperatures. These techniques are also referred to as staged combustion or sub-stoichiometric combustion to limit NO_X formation.

Combustion in hogged fuel boilers commonly occurs on grates, including the hogged fuel boiler at the facility, and does not utilize the types of burners typically employed for low NO_X burner applications. Potential reductions in NO_X emissions from these types of boilers (without add-on controls) are limited by the boiler furnace geometry, air flow controls, and burner zone stoichiometry, making retrofitting applications difficult. The hogged fuel boiler at the facility is regularly inspected for fine-tuning and/or routine maintenance of the boiler systems. As a result, it is expected that the hogged fuel boiler is already optimized for NO_X performance.

In order to achieve effective NO_X reductions from low NO_X burners, a complete replacement of the hogged fuel boiler system, including fans, air control systems, firebox, and steam generating tubes, would likely be required. The Federal Guidance Document identifies several criteria for selecting control measures in the Analysis, including emission reductions through improved work practices, retrofits for sources with no existing controls, and upgrades or replacements for existing, less effective controls. None of these criteria identify or recommend whole replacement of emission units. Based on the challenges with retrofitting the hogged fuel boiler and the Federal Guidance Document criteria, low NO_X burner technology for the hogged fuel boiler was excluded from further consideration in the Analysis.

4.2 Step 2—Selection of Emissions

See Section 2.1 for descriptions of the NO_X emission unit and emission rate used in the Analysis.

4.3 Step 3—Characterizing Cost of Compliance

Table 4-1 (attached) presents the detailed cost analyses of the technically feasible NO_X control technologies. A summary of the cost of compliance, expressed in $/ton, is presented below in Table 4-2:

Table 4-2
Feasible NO_X Control Technologies Cost Analysis

Emission Unit ID	Emission Unit Description	Control Technology	Cost of Compliance ($/ton)
94-30-01	Keeler Boiler	SNCR	$11,149

The actual cost of installing and operating SNCR on the Keeler boiler could be understated in Table 4-2. Due to the facility's remote location, the cost of obtaining reagent for an SNCR system would be significantly higher than the typical facility employing SNCR. In addition, the boiler configuration and physical layout of the plant would make the siting of an SNCR system particularly challenging. As a result, the actual cost of installing and operating an SNCR system at the facility would likely be higher than what is stated above.

4.4 Step 4—Characterizing Time Necessary for Compliance

Several steps will be required before the control device is installed and fully operational. After selection of a control technology, all of the following will be required: permitting, equipment procurement, construction, startup and a reasonable shakedown period, and verification testing. It is anticipated that it will take up to 24 to 36 months to achieve complete installation and commissioning of a retrofit SNCR system.

4.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

4.5.1 Energy Impacts

Direct energy impacts will result from the use of SNCR control systems. Energy use (e.g. electricity use) is attributable to the operation of pumps for urea injection into the SNCR and the heating of the urea storage tank. It is important to note that SNCR systems will also result in increased fuel consumption in the combustion unit to mitigate the increased moisture loads caused by urea injection in the flue gas.

Another, less quantifiable, impact from SNCR systems is that the urea production process requires the production and consumption of fossil fuels, as urea is generated from the cracking of natural gas—

a process that employs significant combustion and then a substantial amount of natural gas feedstock. Thus, increases in consumption of urea through the use of SNCR controls will increase fossil fuel production and use.

4.5.2 Environmental Impacts

SNCR units require the use of urea (or aqueous ammonia) injection in the exhaust stream. Any unreacted excess ammonia in the exhaust stream (i.e., ammonia slip) will be released to the atmosphere. Ammonia slip to the atmosphere is a contributor to fine particle formation, which further exacerbates the regional haze issue; ammonia is also considered to be associated with negative human health impacts Hence, there is a trade-off between NO_X emission reductions and generating ammonia slip. Additionally, increased fuel use by the combustion device or in the manufacture of reagents will lead to additional greenhouse gas contributions as well as other regulated pollutants.

EPA data on the sources of visibility impairment in the Caribou and Thousand Lakes Wilderness Areas identifies that the predominant impacts are attributable to forest fires and other types of open burning. EPA's 2028 sector contribution analysis indicates that all non-EGU point sources as a class make up only 18 percent of the impacts on the regional wilderness areas.[3] Of critical importance to the efforts to minimize local Class I visibility impacts is fire management. The Keeler boiler is a key means of minimizing backyard burning as well as to reduce forest fire risk as Collins accepts yard and forest debris for controlled combustion that would otherwise undergo uncontrolled combustion. Imposing increased operating cost on a facility operating in a distressed business sector creates a substantial risk of increasing environmental impacts—both health and visibility—by increasing uncontrolled combustion in the forests and in people's yards.

4.6 Step 6—Characterize the Remaining Useful Life

It is anticipated that the remaining life of the emission unit, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. The emission unit is not subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the expectation is that the control system would be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emission unit.

5 CONCLUSION

This report presents cost estimates associated with installing control devices at the Chester facility to reduce visibility-impairing pollutants in Class I areas and provides the Four Factor Analysis conducted consistent with available CARB and EPA guidance documents. Collins believes that the above

[3] Technical Support Document for EPA's Updated 2028 Regional Haze Modeling; page B-49; https://www.epa.gov/sites/default/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

information meets the state objectives and is satisfactory for CARB's continued development of California's State Implementation Plan as a part of the Regional Haze program.

Based on the costs described above for the controls under consideration, there does not appear to be any control device that, on a dollar per ton of pollutant-controlled basis, would be considered cost effective. In addition, given the extensive pollution controls already in place at the facility, and the effectiveness of the good combustion practices in place at the facility, additional controls would result in limited, if any, visibility improvement. In the absence of significant visibility improvement, it would not be appropriate to require investment in additional controls at this wood products facility.

LIMITATIONS

The services undertaken in completing this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, express or implied, is made. These services were performed consistent with our agreement with our client. This report is solely for the use and information of our client unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, or the use of segregated portions of this report.

TABLES

Table 2-1
Inputs and Parameters
Collins Pine Company—Chester, California

Parameter	Value (units)		
Facility Operations			
Annual Hours of Operation	8,592	(hrs/yr)	(1)
Keeler Boiler			
Heat Input Capacity	242	(MMBtu/hr)	(1)
Annual NO_X Emissions	129	(tons/yr)	(2)
Utility Rates			
Electricity	0.12	($/kWh)	(3)
Water	4.58	($/Mgal)	(a)
Wood Fuel	55.00	($/BDT)	(3)

NOTES:

MMBtu = million British thermal units.

kWh = kilowatt-hour.

Mgal = thousand gallons.

BDT = bone dry ton.

(a) Water cost ($-2019/Mgal) = (water cost [$-2018/Mgal]) / (2018 CEPCI annual index) x (2019 CEPCI annual index)

Water cost ($-2018/Mgal) =	4.55	(4)
2018 CEPCI annual index =	603.1	(5)
2019 CEPCI annual index =	607.5	(5)

REFERENCES:

(1) See Title V Operating Permit no. NSAQMD-CP-01 issued May 14, 2014 by the Northern Sierra Air Quality Management District.

(2) Information provided by Collins Pine Company. California's screening process was based on 2017 emissions data, and the Agency requested this data should be used in the analysis unless an alternate year was pre-approved.

(3) Information provided by Collins Pine Company.

(4) Water costs obtained from "50 Largest Cities Water & Wastewater Rate Survey" prepared Black & Veatch Management Consulting, LLC dated 2018-2019. See exhibit B, Figure 19. Note this reference was provided in the EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Noncatalytic Reduction" calculation spreadsheet.

(5) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices. The 2019 index was utilized over 2020 due to the volatility in prices during the COVID-19 pandemic.

Table 4-1
Cost Effectiveness Derivation for Selective Non-Catalytic Reducer Installation
Collins Pine Company—Chester, California

Emissions Unit	Input Parameters				Pollutant Removed by Control Device		Normalized Stoichiometric Ratio [d]	Operating Parameters				
	Heat Input Capacity [1] (MMBtu/hr)	Uncontrolled NO_X Emissions Estimate		Uncontrolled NO_X Emissions in Flue Gas [2] (lb/MMBtu)	Hourly [b] (lb/hr)	Annual [c] (tons/yr)		Reagent Mass Consumption [e] (lb/hr)	Reagent Solution Flowrate [f] (gal/hr)	Power Demand [g] (kW)	Water Demand [h] (gal/hr)	Additional Fuel Usage [i] (MMBtu/hr)
		Hourly [a] (lb/hr)	Annual [1] (tons/yr)									
EPA COST MANUAL VARIABLE	**Q_B**	**--**	**--**	**NO_{Xin}**	**--**	**--**	**NSR**	**$m_{reagent}$**	**q_{sol}**	**P**	**q_{water}**	**ΔFuel**
Keeler Cogeneration Boiler	242	30.0	129	0.19	7.51	32.3	1.43	42.6	8.98	38.1	40.9	0.35

Emissions Unit	Direct Cost	Indirect Cost	Total Capital Investment [l]	Capital Recovery Cost of Control Device [m]	Direct Annual Costs						Total Indirect Annual Costs [u]	Total Annual Cost [v]	Annual Cost Effectiveness [w]
	Capital Cost [j]	Balance of Plant Cost [k]			Maintenance Labor and Material Cost [o]	Reagent Usage [p]	Utilities			Total Direct Annual Costs [27]			
							Electricity Cost [r]	Water Usage Cost [s]	Fuel Additive Cost [t]				
EPA COST MANUAL VARIABLE	**$SNCR_{COST}$**	**BOP_{COST}**	**TCI**	**CR**	**--**	**--**	**--**	**--**	**--**	**DAC**	**IDAC**	**TAC**	**($/ton)**
Keeler Cogeneration Boiler	$640,643	$776,734	**$1,967,465**	$135,320	$29,512	$143,651	$39,251	$1,609	$9,333	$223,355	$136,205	**$359,561**	**$11,149**

NOTES:

(a) Uncontrolled hourly NO_X emissions estimate (lb/hr) = (uncontrolled annual NO_X emissions estimate [tons/yr]) x (2,000 lb/ton) / (annual hours of operation [hrs/yr])

Annual hours of operation (hrs/yr) = 8,592 (1)

(b) Hourly pollutant removed by control device (lb/hr) = (uncontrolled hourly NO_X emissions estimate [lb/hr]) x (control efficiency [%] / 100)

Control efficiency (%) = 25.0 (3)

(c) Annual pollutant removed by control device (tons/yr) = (uncontrolled annual NO_X emissions estimate [tons/yr]) x (control efficiency [%] / 100)

Control efficiency (%) = 25.0 (3)

(d) Normalized stoichiometric ratio = ([2] x [uncontrolled NOX emissions in flue gas {lb/MMBtu}] + [0.7]) x (control efficiency [%] / 100) / (uncontrolled NOX emissions in flue gas [lb/MMBtu]); see reference (4).

Control efficiency (%) = 25.0 (3)

(e) Reagent mass consumption (lb/hr) = (uncontrolled NO_X emissions in flue gas [lb/MMBtu]) x (heat input capacity [MMBtu/hr]) x (normalized stoichiometric ratio) x (60.06 lb-urea/lb-mole) / (46.01 lb-NO_2/lb-mole) / [theoretical stoichiometric ratio]); see reference (5).

Theoretical stoichiometric ratio = 2 (6)

(f) Reagent solution flowrate (gal/hr) = (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (aqueous reagent solution density [lb/ft³]) x (7.4805 gal/ft³); see reference (7).

Aqueous reagent solution concentration (%) = 50.0 (7)

Aqueous reagent solution density (lb/ft³) = 71.0 (7)

(g) Power demand (kW) = (0.47) x (uncontrolled NO_X emissions in flue gas [lb/MMBtu]) x (normalized stoichiometric ratio) x (heat input capacity [MMBtu/hr]) / (net plant heat rate [MMBtu/MWh]) + (power required to heat tank [kW]); see reference (8).

Net plant heat rate (MMBtu/MWh) = 10.0 (9)

Power required to heat tank (kW) = 35.0 (10)

(h) Water demand (gal/hr) = (4) x (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (density of water [lb/gal]); see reference (11).

Aqueous reagent solution concentration (%) = 50.0 (7)

Density of water (lb/gal) = 8.345

(i) Additional fuel usage (MMBtu/hr) = (9) x (heat of vaporization of water [Btu/lb]) x (reagent mass consumption [lb/hr]) x (MMBtu/1,000,000 Btu); see reference (12).

Heat of vaporization of water (Btu/lb) = 900 (12)

(j) Capital cost ($) = (capital cost [1999 $/MMBtu/hr]) x (heat input capacity [MMBtu/hr]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 1999)

Capital cost (1999 $/MMBtu/hr) = 1,700 (13)

Chemical engineering plant cost index for 2019 = 607.5 (14)

Chemical engineering plant cost index for 1999 = 390.6 (14)

(k) Balance of plant costs ($) = (213,000) x ([heat input capacity {MMBtu/hr}] / [net plant heat rate {MMBtu/MWh}])^(0.33) x (hourly pollutant removed by control device [lb/hr])^(0.12) x (retrofit factor); see reference (15).

Net plant heat rate (MMBtu/MWh) = 10.0 (9)

Retrofit factor = 1.00 (15)

(l) Total capital investment ($) = (1.3) x ([capital cost {$}] + [balance of plant cost {$}]) + (reagent storage tank cost [$]) + (reagent storage tank construction [$]); see reference (16).

Reagent storage tank ($) = 74,875 (17)

Reagent storage area construction ($) = 50,000 (18)

(m) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (19).

Control device capital recovery factor = 0.0688 (n)

Table 4-1 (Continued)

Cost Effectiveness Derivation for Selective Non-Catalytic Reducer Installation
Collins Pine Company—Chester, California

(n) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (20).

Interest rate (%) = 3.25 (21)

SNCR economic life (yr) = 20.0 (22)

(o) Annual maintenance cost ($) = (0.015) x (total capital investment [$]); see reference (23).

(p) Annual reagent usage cost ($) = (reagent solution flowrate [gal/hr]) x (reagent cost [$/50% urea solution]) x (annual hours of operation [hrs/yr])

Reagent rate ($/50% urea solution) = 1.86 (q)

Annual hours of operation (hrs/yr) = 8,592 (1)

(q) Reagent rate ($/50% urea solution) = (reagent cost [2016 $/50% urea solution]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 2016)

Reagent rate (2016 $/50% urea solution) = 1.66 (24)

Chemical engineering plant cost index for 2019 = 607.5 (14)

Chemical engineering plant cost index for 2016 = 541.7 (14)

(r) Annual electricity cost ($) = (power demand [kWh]) x (electricity rate [$/kWh]) x (annual hours of operation [hrs/yr])

Electricity rate ($/kWh) = 0.120 (1)

Annual hours of operation (hrs/yr) = 8,592 (1)

(s) Annual water usage cost ($) = (water demand [gal/hr]) x (Mgal/1,000 gal) x (water rate [$/Mgal]) x (annual hours of operation [hrs/yr])

Water rate ($/Mgal) = 4.58 (1)

Annual hours of operation (hrs/yr) = 8,592 (1)

(t) Annual fuel additive cost ($) = (additional fuel usage [MMBtu/hr]) x (annual hours of operation [hrs/yr]) x (wood fuel rate [$/BDT) / (high heat value of wood [MMBtu/BDT); see reference (25).

Annual hours of operation (hrs/yr) = 8,592 (1)

Wood fuel rate ($/BDT) = 55.0 (1)

High heat value of wood (MMBtu/BDT) = 17.48 (26)

(u) Total indirect annual cost ($) = (0.03) x (annual maintenance cost [$]) + (capital recovery cost [$]); see reference (28).

(v) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(w) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-1, Inputs and Parameters.

(2) Performance test dated September 15 & 16, 2020 by Environmental Technical Services, Inc.

(3) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See Table 1.2. The low end of the range is assumed due as retrofit applications achieve lower efficiencies than new constructions fit with SNCR technology.

(4) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.17.

(5) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.18.

(6) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. Assumes theoretical stoichiometric ratio for urea.

(7) EPA Air Pollution Control Cost Manual, Section 4, Chapte 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.19 and 1.20.

(8) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.42.

(9) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.3.1.

(10) Information provided by Chromalox vendor. Assumes heating of urea is required to a minimum of 95°F.

(11) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.45.

(12) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.48.

(13) EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR) issued July 15, 2003. Assumes the average capital cost.

(14) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices. The 2019 index was utilized over 2020 due to the volatility in prices during the COVID-19 pandemic.

(15) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.37. Assumes retrofit factor.

(16) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.35.

(17) Cost representative of 12,500 gallon double-wall, heated, storage tank provided by National Tank Outlet and Chromalox. Cost includes freight charges, but excludes sales tax.

(18) Assumes engineering estimate cost of construction for a covered storage tank (e.g., including engineering design services, concrete/foundation/secondary containment area work, and structure construction).

(19) EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.

(20) EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.

(21) Per EPA recommendation, the current bank prime rate is used. Bank prime loan rate for June 25, 2021 retrieved from the Federal Reserve.

(22) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.4.2.

(23) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.39.

(24) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.5.

(25) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.49.

(26) 40 CFR, Subchapter C, Part 98, Subpart C. See Table C-1 "Default CO2 Emission Factors and High Heat Values of Various Types of Fuel". Factor for wood and wood residuals.

(27) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.38.

(28) EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.52 and 1.53.

APPENDIX A

MEMO

August 18, 2021

To: Maul Foster & Alongi, Inc.
Attn: Leslie Riley
6 Centerpoint Drive
Suite 360
Lake Oswego, OR 97305

From: Sheldon Schultz
Via: Email cc: Howard Hughes

Subject: Reply to your Email of August 10 regarding FGR and SNCR at the Collins Pine facility in Chester, CA.

Flue Gas Recirculation (FGR)

Background:

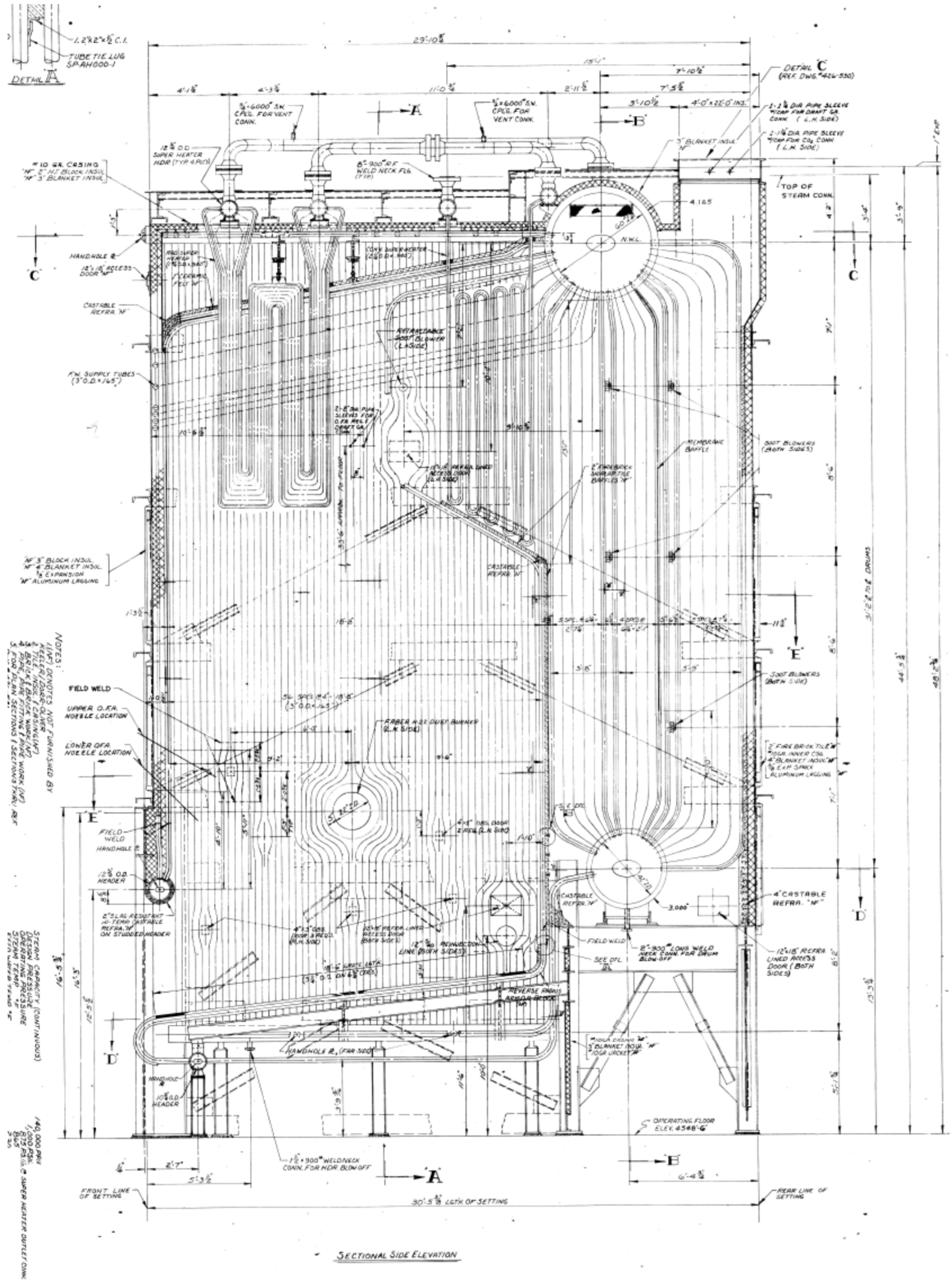
Flue gas recirculation is a technique used to reduce emissions of NOx. Flue gas recirculation normally draws flue gas from the stack to a fans suction and the fan pressurizes the gas and injects the flue gas into the combustion air entering the boiler. The mass of combined combustion air and flue gas is greater than for combustion air only, therefore the flame temperature is reduced. Flue gas recirculation can provide a significant reduction in NOx when the combustion process takes place producing a temperature greater than about 2500 F where thermal NOx production becomes significant. The combustion temperature of wood in a boiler furnace generally does not result in a flame temperature reaching the thermal NOx level.

NOx produced from combustion of wood fuel is primarily fuel bound nitrogen conversion. NOx produced from burning wood results from nitrogen entering the furnace chemically bound in the wood. When wood experiences high temperatures in the furnace the volatile compounds cook off as gas leaving the fixed carbon or char fraction of the wood to burn out on the grate. A minor fraction of the volatile compounds are hydrogen cyanide and ammonia (HCN & NH_3). These two compounds are the nitrogen containing precursors that lead to the formation of NOx. Generally these species persist to near the top of the flame envelope and a fraction of them are converted to NO. The percent of the precursors that become NO is thought to depend on the temperature at the top of the flame envelope and the concentration of oxygen in the region. Increased temperature and higher oxygen concentrations result in higher levels of NO.

The flame temperature resulting from wood combustion is dependent on the fuel moisture content, the level of excess oxygen used in combustion and the furnace design that absorbs radiant heat from the flame and hot flue gas. The effort to lower NOx emissions by reducing temperature must be balanced with the combustion requirement for high temperature to oxidize the fixed carbon and volatile compounds cooked out from the wood. The Babcock and Wilcox reference used by boiler engineers and operators “Steam its Generation and Use” recommends the minimum adiabatic flame temperature for boiler design is 2300 F. My experience is that boilers with an adiabatic flame temperature of 2000 F perform acceptably, because many boilers burning wet wood waste struggle with combustion performance when the fuel moisture increases and the temperature falls below 2000 F.

I have been to the Collins Pine facility in Chester, CA. My work at Chester was focused on improved control of CO emissions. I performed some testing on the boiler by monitoring flue gas emissions and oxygen levels at the boiler furnace outlet. Following analysis of the test results and observation I designed an alteration to the wood fuel distributors that improved the distribution of wood fuel particles on the grate. The improved fuel distribution led to improved control of CO emissions.

A side elevation drawing of the boiler is shown below. Copies of copies loose definition and contrast so that the dimensions are lost, for reference the depth of the grate is 18 feet 6 inches. The height of the furnace to the base of the bull nose is only about 19 feet the height to the bottom of the radiant super heat bundle is about 25 feet. Normally the height of a wood fired boiler furnace is 2.5 to 3.5 times the boiler width or depth. The width of the boiler is slightly more than 16 feet. The Maximum Continuous Rating (MCR) of the boiler is 140,000 pounds per hour. The fuel energy input corresponding to MCR is 240 MMBtu/hr. resulting in a grate energy release of approximately 800,000 Btu/hr.-ft^2. This is a relatively low energy release at MCR, the norm is 1,000,000 Btu/hr-ft^2. The energy density results in a low pressure drop of combustion air across the grate bars and low pressure drop leads to the fuel distribution having a larger than normal negative impact on air distribution. Another way to say this is that a concentration of fuel results in diversion of combustion air to regions of the grate with less fuel, exactly opposite of what is desired. A concentration of fuel with insufficient combustion air results in a taller flame envelope. My recollection of peak flame height at the Chester facility is 12 to 14 feet with the peak about 6 feet from the boiler front wall.

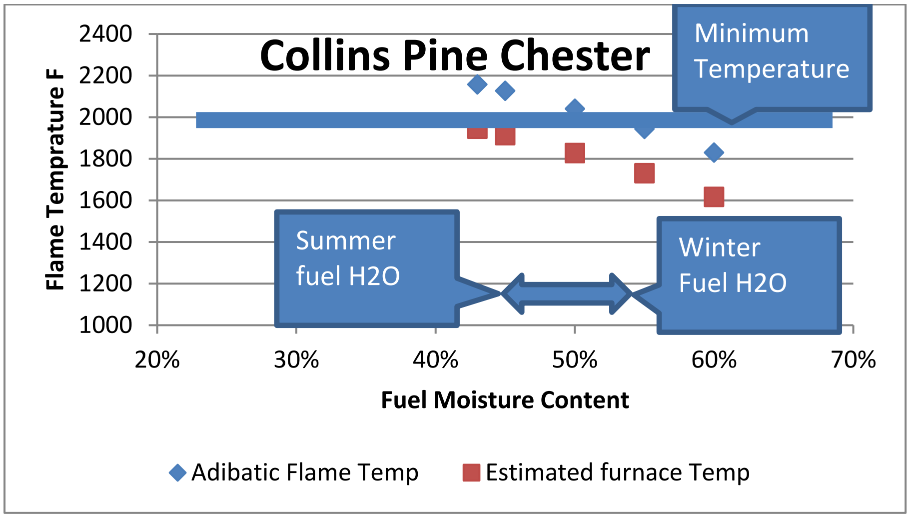


SECTIONAL SIDE ELEVATION

Answers to Specific Questions about FGR:

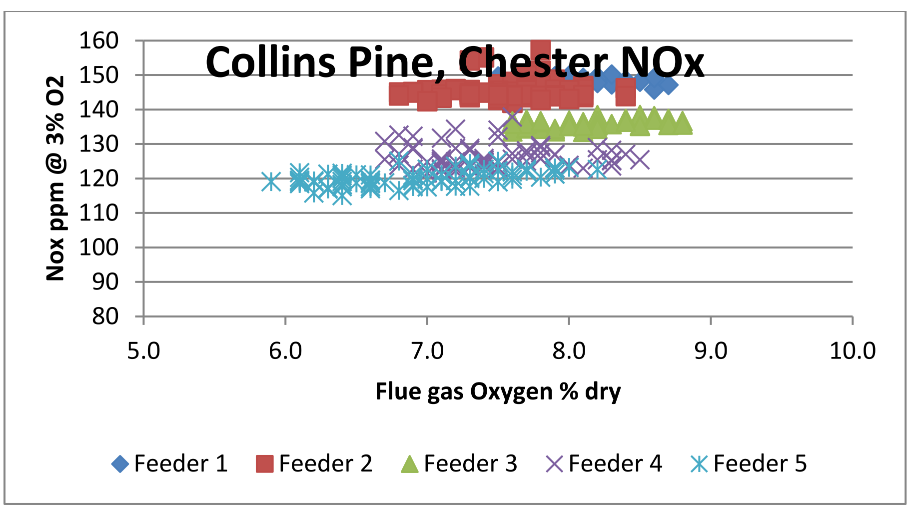
1. A. How will moisture content and O2 levels affect NOx?

Fuel moisture content changes the average flame temperature in the furnace. The graph below demonstrates the adiabatic flame temperature and predicted furnace temperature across a reasonable moisture content range.



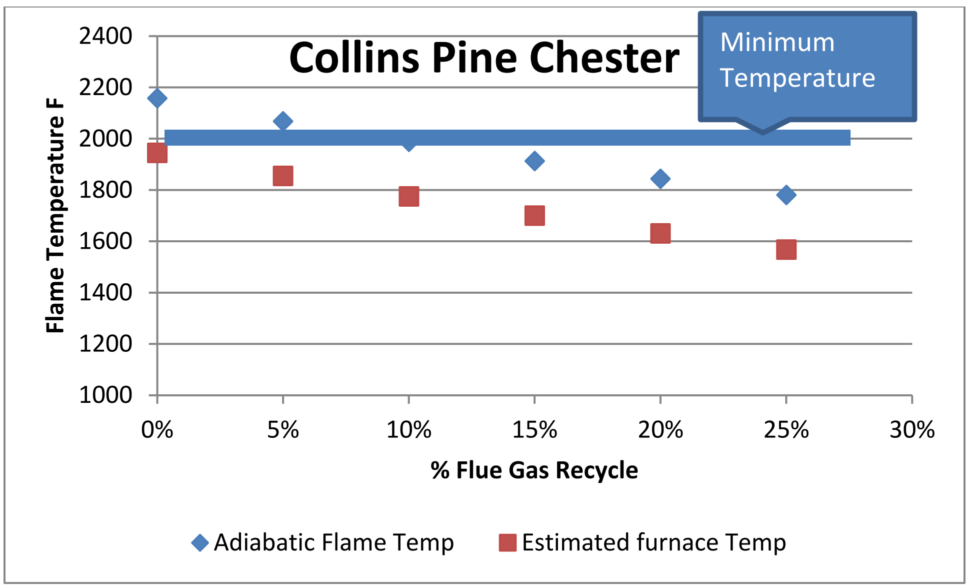
Higher temperature increases the conversion of fuel bound nitrogen to NO. The EPA research paper "Chemistry of Fuel Nitrogen Conversion to Nitrogen Oxides in Combustion" suggest that at 1742 F the conversion is 55% of what results from a temperature of 2012 F.

Virtually all chemical reactions are controlled to some extent by the concentrations of the reactants and oxygen is one of the reactants in the conversion of NH3 and CHN to NO. Increasing oxygen content in the furnace region where the precursors are reactive yields more NO. The graph below depicts some of the NO data from Chester. Note that the NO curves are generally upward sloping.



1. B. How will the control efficiency change seasonally?

The graph below depicts the relationship between flame and furnace temperature as FGR is applied to the process. The amount of FGR is limited to the amount that can be applied before the flame temperature drops below 2000 F. This graph begins with the flame temperature corresponding to the lowest moisture content fuel that is anticipated, which is about 42%. Using the two graphs the furnace can accept 10% flue gas recycle when burning the lowest expected moisture content fuel and the application peaks with about 10% of the normal flue gases recycled back to the combustion air supply. In the spring, late fall and winter the fuel moisture content is high enough that beneficial application of FGR is unlikely.



1.C. What is the expected overall control efficiency?

Based on the EPA funded research the expected change in precursor conversion resulting from using FGR to drop the flame temperature from 2158 F to 2000 F is 25% for the modeled fuels in a test tube. Boiler furnaces produce the trends indicated in test tubes but in my experience never reach the levels obtained in research. My estimate of NO reduction is between 15 and 20% when burning the driest fuel.

1.D. How is the boiler at Chester suited for this technology? Will flame stability be an issue? Will it result in higher CO and hydrocarbon emissions.

The Chester boiler is suitable for flue gas recirculation. The flue gas should be obtained from the cleanest location, which is the ESP stack. The duct and fan handling the flue gas should be insulated to prevent condensation of flue gas moisture on the inner surface which leads to aggressive corrosion. Flue gas should be pressurized adequately so it can injected on the hot combustion air side of the air pre-heater, this is to prevent condensation.

Flame stability and increased emissions of CO and hydrocarbon are not anticipated so long as the minimum temperature limit is not exceeded.

1.E. How much will the retrofit cost?

I have not visited Chester for a number of years. Collins Pine has upgraded the facility since my last visit by replacing a wet ESP with a new dry ESP and removed a flue gas fuel dryer that was worn out and leaking in a large amount of ambient air. I'm unable to provide a cost estimate because I can't envision the physical arrangement.

What I can tell you is the mass flow or recirculation should be designed for 40,000 pounds per hour, 400 F and about 16,000 ACFM. The fan pressure rating should be about 10 in-H2O to accommodate duct losses, damper control and the static pressure in the boiler under grate. The duct should be approximately 32 inches inside diameter and should be insulated with 3 inch thick fiberglass insulation. The fan will have a 50 HP motor that will consume 33 KW.

1.F. What is the expected utility usage for FGR? We need enough to know enough to be able to calculate cost effectiveness.

My estimate is that FGR would be effective about 30% of the time and the impact of FGR properly applied would be a NOx reduction from 135 ppm @ 3% O2 to 115 to120 ppm @3% O2.

2. SNCR

   2.A. What are some of the challenges in a retrofit for a biomass boiler?
   The process of applying SNCR is primarily one of locating the furnace region where the proper temperature for efficient reaction exists after the CO is oxidized in the lower furnace. In the proper temperature (1600 F for ammonia) region the task is one of mixing the reducing agent with the flue gas. The last significant process condition is the time available for the reducing reaction to take place.

   2.B. How are the dimensions of the boiler at Chester suited for this technology?

   The Chester boiler is somewhat unique because the grate surface is larger than is typical and the furnace height is quite a bit shorter than normal. In addition to the physical size differences the Chester boiler has a radiant super heaters in the top of the short furnace. The furnace height above the flame envelope (where CO is oxidized) and below heat absorbing surfaces such as radiant super heaters is the physical space available for application of SNCR if the necessary flue gas temperature is available. The residence time for the SNCR reaction is the average time of flue gas passage through this furnace volume. A reaction zone with up to .5 seconds residence time is ideal but residence time on the order of .3 + seconds is required for effective control. The required time is not available at Chester, the flue gas velocity in the upper furnace is 19 feet per second and distance between the top of the flame and the beginning of the bull nose where the flue gas velocity increases is about 4 feet, resulting in a time of about .2 seconds.

In addition to the reaction efficiency between the reducing agent and NO, SNCR design must be effective and control slip of ammonia. The short residence time would require a higher than normal amount of reducing agent for significant NOx control. Higher than normal reagent application along with the higher than normal heat absorption in the upper furnace from the radiant super heater will rapidly cool the flue gas to temperatures where higher than normal levels of ammonia slip are expected.

2.C. Is the temperature within the boiler high enough for the reduction reaction?

The temperature in the upper furnace is high enough for the reduction reaction using ammonia to take place. The temperature is not adequate for application using urea reagent.

2.D. We stated in the DRAFT Regional Haze report that we expect an SNCR to have 20-25% control. Is this reasonable considering the temp, size and moisture content?

One can't address control efficiency without simultaneously evaluating ammonia slip. I believe 30% control is likely provided the slip limit is 50 ppm, if the slip limit is 25 ppm my estimate is 20 to 25%.

I. Federal Land Manager Comments and CARB Responses

Under provisions in the federal Regional Haze Rule[74], states must consult with federal land managers (FLM) during the development of the regional haze SIP including an advanced 60-day review. As technical analyses were being developed by the WRAP, CARB staff engaged in monthly teleconferences that provided for continuous informal engagement with federal land managers. As the draft Regional Haze Plan was being developed, CARB staff held multiple informal consultation teleconferences with staff from the National Park Service (NPS) and the U.S. Forest Service (USFS). During these teleconferences, CARB staff provided updates on Regional Haze Plan development, technical analyses, planned approaches to conducting the reasonable progress analyses, and strategies for achieving emission reductions to improve visibility in Class I areas.

Representatives from FLM agencies were provided the opportunity to formally review and comment on an initial draft of California's Regional Haze Plan more than 60 days prior to the start of the public comment period. A draft of California's Regional Haze Plan was transmitted to representatives from the Bureau of Land Management, NPS, U.S. Fish and Wildlife Service, and USFS on February 9, 2022. CARB requested that FLM agencies provide formal comments on the draft by April 11, 2022.

[74] 40 CFR Section 51.308(i)(2)

Comments Received from Federal Land Managers

Following the formal consultation period, comment letters were received from NPS and USFS. CARB appreciates the engagement of the federal land managers during the development of the Regional Haze Plan and the feedback provided during the formal consultation period.

In the comment letter provided by NPS, the agency noted that they appreciate CARB’s mobile source emission reduction measures that reduce pollutants contributing to haze, and emission reductions from point sources achieved through other pollution control programs that also reduce haze pollutants. NPS provided suggestions focused on stationary sources. USFS was largely satisfied with CARB’s plan and agreed that NOx emissions are extremely important and warrant extensive analyses. USFS provided suggestions focused on accounting for prescribed fire emissions and oxides of sulfur (SOx) emissions.

CARB’s responses to suggestions provided by federal land managers in their comment letters are provided in the pages that follow. The FLM comment letters are provided following CARB’s responses.

Following the formal consultation period, two excel workbooks were received from NPS in addition to the formal comment letter. The excel workbooks are available for download from CARB's Regional Haze website: https://ww2.arb.ca.gov/our-work/programs/california-state-implementation-plans/statewide-efforts/regional-haze.

CARB Response to Comments

To aid in organization, suggestions in the comments provided by federal land managers are paraphrased and numbered below in the italicized text. CARB responses follow in the non-italicized text.

CARB response to comments received from NPS

1. *By focusing exclusively on mobile source NOx emissions and deferring source controls to other air pollution control programs, the current draft SIP misses significant opportunities to specifically address haze. Further, this approach removes the NPS ability to contribute substantively to haze planning.*

Emissions from a host of sources contribute to regional haze in California's Class I areas. Unlike many areas of the country where a single stationary source or group of stationary sources are the dominant source of emissions, the cocktail of emissions contributing to regional haze pollution in California is dominated by mobile sources, particularly, NOx emissions from mobile sources.

Mobile sources account for nearly 80 percent of NOx emissions in California. Reducing emissions from this source sector is necessary to meet a host of air quality targets including reducing visibility impairing pollutants in Class I areas, meeting health-based air quality standards, and addressing climate change. As a result of the significant air quality challenges that California is working to address and the primary role that mobile sources play in contributing to these air quality challenges, the U.S. Congress provided CARB with the unique authority to control emissions from mobile sources beyond the limits set by the federal government. California is the only state that has been provided the authority to control mobile source emissions and thus these controls are appropriate for the Regional Haze Plan.

This Regional Haze Plan is focused on making progress towards reaching natural visibility conditions by 2064 and meeting interim visibility goals established for 2028. Substantial statewide emission reductions are projected by 2028 and result from the implementation of mobile source control measures developed and adopted by CARB. Implementation of measures already adopted at the time the inventory was developed for this plan are expected to reduce statewide NOx emissions by more than 400 tons per day, or 146,000 tons per year, by 2028. As part of this SIP, CARB is committing to achieve a reduction of an additional 40 tons of NOx per day, or 14,600 tons of NOx per year, by 2028 through the adoption and implementation of four mobile source control measures. These emission reductions are significant and projected to improve visibility in Class I areas impacted by anthropogenic emissions from California. Further, there is no requirement for states to select a certain number of sources or percentage of emissions during this planning period; however, by focusing the long-term strategy on mobile sources, California is addressing the most substantial portion of statewide emissions that contribute to haze and believes the process employed for source selection has achieved a reasonable result.

Regional haze planning is an iterative process. Every ten years, states will take a fresh look at visibility conditions, emissions contributing to visibility impairment, and assess opportunities to make meaningful improvements in visibility. As emission reductions are achieved and California continues to drive emissions to zero, the types of pollutants driving visibility impairment will change. This iterative process allows states to make informed planning decisions, supported by science, and adjust strategies as needed.

California has widespread and unique air quality challenges stemming from a large population, complex terrain, and prevailing meteorological patterns. CARB is responsible for protecting the public from the harmful effects of air pollution and developing programs to fight climate change. In this role, CARB is continuously working to meet health-based air quality standards, improve air quality in communities, and address climate change. As a result of this work, the development of measures to reduce emissions does not start and stop with regional haze planning.

CARB has taken and is continuing to take a lot of regulatory actions to address the State's substantial air quality challenges. There are notable overlaps among the criteria pollutants and haze pollutants, which are particularly magnified in California for this planning period where NOx is a significant driver of haze formation and also a precursor for PM and ozone formation. The State's ongoing struggle with air quality and our unique mobile source authority have compelled CARB to take aggressive regulatory actions to meet attainment deadlines for health-based standards. While the regulatory actions and timelines associated with many of these regulatory actions were prompted by efforts to meet health-based standards, the reductions associated with these actions will benefit both air quality in communities and regional haze in Class I areas.

CARB welcomes input from the federal land managers. CARB's public process for the development and adoption of statewide emission control measures for reducing regional haze, attaining criteria pollutant standards, mitigating climate change, and reducing exposure to toxic air contaminants provides opportunities for all stakeholders, including federal land managers, to engage and contribute their insight, knowledge, and expertise. Information on CARB's past and ongoing rulemaking activities is available on CARB's website.[75] Board meetings are typically held on a monthly basis. Meeting agendas are posted ten days prior to meetings and stakeholders are encouraged to provide input either through testimony at the meetings or by submitting written comments to the docket. Stakeholders can

[75] https://ww2.arb.ca.gov/rulemaking-activity

subscribe[76] to a listserv to receive notifications about meeting agendas and opening of comments periods.

The process for the development and adoption of stationary source and area source control strategies by local air districts also includes a public process with opportunities for stakeholders to engage and contribute. Information about proposed rules, upcoming workshops, and district board meetings can be found on websites[77] maintained by local air districts.

Even with development of a mobile source-focused strategy, NPS is still able to discuss their assessment of visibility impairment and recommendations on development and implementation of strategies to address impairment.[78] CARB welcomes NPS's partnership in developing strategies to reduce visibility impairment

2. *Emissions from CARB's stationary sources are significant. NPS recommends that CARB amend the draft SIP and include additional point source four-factor analyses in the reasonable progress determinations that assess opportunities to address haze causing SO_2 and NOx emissions.*

Regional haze planning is an iterative process. Every ten years, CARB will take a fresh look at visibility conditions, emissions contributing to visibility impairment, and assess opportunities to make meaningful improvements in visibility. As emission reductions are achieved and California continues to drive emissions to zero, the types of pollutants driving visibility impairment will change. This iterative process allows states to make informed planning decisions, supported by science, and adjust strategies as needed.

CARB's strategy in the first regional haze planning period was focused on mobile source measures aimed at reducing NOx and SOx emissions and the required best available retrofit technology (BART) analyses, which required states to evaluate larger, older sources from 26 categories during the first planning round to determine whether emission controls should be installed to improve visibility at Class 1 areas. One facility was identified during the BART analyses and needed to install BART-level SOx controls. As a result of the implementation of the statewide mobile source control measures and the installation of controls at the facility identified during the BART analyses, NOx and SOx emissions declined significantly and the amount of visibility impairment resulting from ammonium nitrate and ammonium sulfate decreased.

Technical analyses used to support planning efforts for this regional haze plan indicate that ammonium nitrate remains a dominant source of visibility impairment attributable

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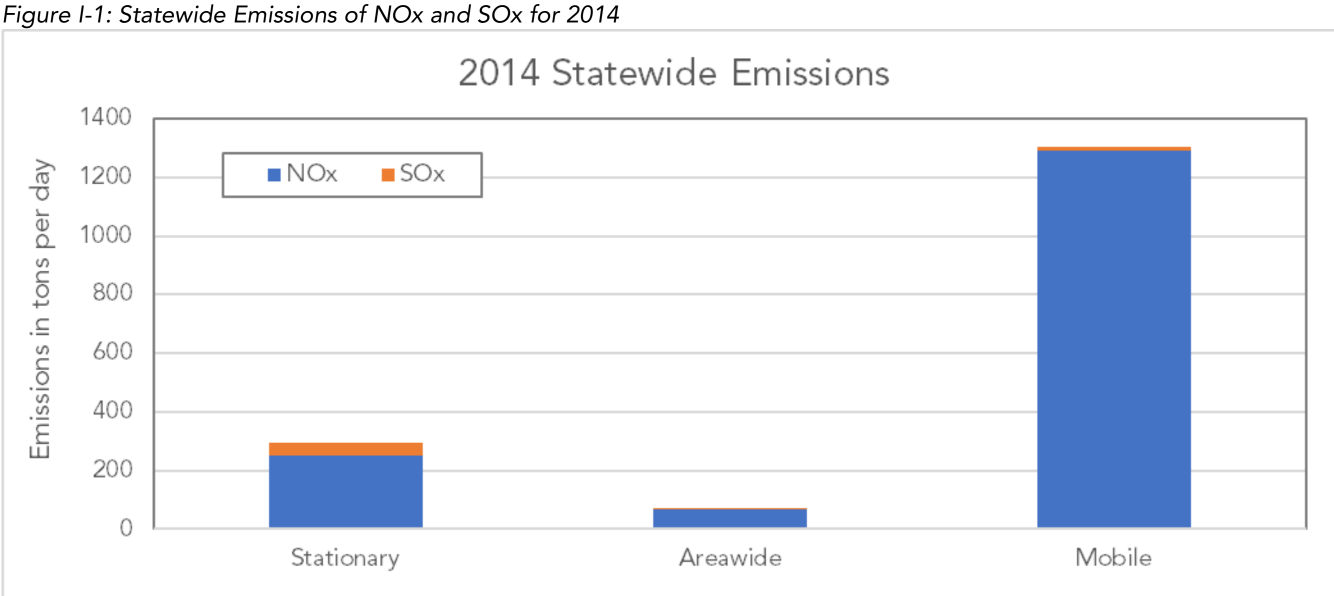
[76] https://ww2.arb.ca.gov/our-work/programs/board-meetings
[77] https://ww2.arb.ca.gov/california-air-districts
[78] 40 CFR 51.308(i)(2)

to anthropogenic sources. For the 2014-2018 time period, source apportionment modeling indicates that ammonium nitrate accounts for an average of 49 percent of visibility impairment in California's Class I areas attributable to anthropogenic sources. In contrast, ammonium sulfate accounts for an average of 9 percent of visibility impairment attributable to anthropogenic sources for this time period. As shown in Figure I-1, SOx emissions account for a small portion of statewide emissions relative to NOx. To improve visibility for this planning period, California is focused on reducing NOx emissions. Reducing NOx emissions will be the most effective means to reduce the formation of ammonium nitrate.

Figure I-1: Statewide Emissions of NOx and SOx for 2014



Emissions from mobile sources account for nearly 80 percent of statewide NOx emissions. Measures aimed at reducing NOx emissions from mobile sources will be effective at reducing emissions that contribute to the formation of ammonium nitrate.

California does have numerous stationary sources. CARB's comprehensive inventory of emissions from the stationary source sector has a level of detail that goes beyond minimum reporting requirements. For the 2017 National Emissions Inventory, CARB reported NOx emissions from more than 13,000 stationary sources. However, annual NOx emissions were less than ten tons per year (tpy) at more than 95 percent of these sources. For the same reporting year, CARB reported SO_2 emissions for more than 12,000 stationary sources. Annual SO_2 emissions were less than ten tpy at more than 99 percent of these sources.

California's 35 local air districts are responsible for controlling emissions from stationary sources. To reduce emissions that contribute to nonattainment of health-based standards and to improve air quality in local communities, air districts work to develop rules to control emissions from stationary sources. CARB's website provides a local air district rule tool[79] that allows users to search, view, and download information related to current air district rules.

Recent work to reduce emissions from large stationary sources across California was initiated by the 2017 adoption of California Assembly Bill (AB) 617, which was developed to improve air quality in communities. Stationary sources in 18 of California's local air districts are subject to the expedited best available retrofit control technology (BARCT) requirements of AB 617. Sources subject to expedited BARCT are identified in CARB's pollution mapping tool,[80] and the BARCT schedules adopted by air districts are summarized on CARB's Expedited BARCT website.[81]

Implementation of emissions reduction measures required by AB 617 could benefit the regional haze program. CARB will provide an update on the implementation of the AB 617 expedited BARCT requirements as they relate to regional haze in the next progress report (due January 2025).

3. *NPS recommends that all states consider opportunities to reduce both NOx and SO_2 emissions from stationary sources as part of regional haze planning.*

California is accounting for State specific factors and taking an evidence-based approach to identify haze pollutants that are most important for this round of regional haze planning. As discussed in Chapter 5 of this Regional Haze Plan and in the responses to previous comments, technical analyses indicate that ammonium nitrate plays a dominant role in visibility impairment attributable to anthropogenic emissions. NOx emission reductions have been successful at reducing particle pollution and improving visibility. Therefore, the focus of California's strategy for this regional haze planning period is on reducing NOx emissions, a precursor to the formation of ammonium nitrate. Mobile sources account for nearly 80 percent of NOx emissions in California. Thus, with our unique authority, California's strategy is focused on mobile source control measures to reduce NOx emissions. Further, technical analyses used to support the development of this Regional Haze Plan indicate that most visibility impairment from ammonium sulfate is attributable to natural and international anthropogenic sources, which the State cannot be directly control.

CARB's strategy in the first regional haze planning period was focused on mobile source measures aimed at reducing NOx and SOx emissions and the required best available retrofit technology (BART) analyses. As a result of the implementation of measures in the first planning period, statewide NOx and SOx emissions declined and the amount of visibility impairment resulting from ammonium nitrate and ammonium

[79] https://ww2.arb.ca.gov/current-air-district-rules
[80] https://www.arb.ca.gov/ei/tools/pollution_map/
[81] https://ww2.arb.ca.gov/expedited-barct

sulfate decreased. The technical analyses indicate that further reductions in ammonium nitrate are needed in this planning period to meaningfully improve visibility.

Regional haze planning is an iterative process. As NOx emissions are reduced, the pollutants driving visibility impairment will change. The iterative process laid out for regional haze planning allows states to make informed planning decisions, supported by science, and adjust strategies as needed.

4. *NPS recommends that CARB address SO_2 emissions from their stationary point sources because of their contributions to impairment in both in-state and out-of-state NPS Class I managed areas.*

As stated in responses to previous comments, CARB is taking an evidence-based approach to the development of this Regional Haze Plan to ensure that emission reductions measures relied upon in the long-term strategy make a meaningful contribution to visibility improvement. Technical analyses used to support plan development indicate that most ammonium sulfate is attributable to natural and international sources. The portion of ammonium sulfate attributable to domestic anthropogenic sources that is projected to contribute to haze in NPS managed Class I areas in California is less than one inverse megameter. Generally, changes of less than ten inverse megameters are not perceptible.

Ammonium nitrate is a dominant component of haze attributable to domestic anthropogenic sources. NOx is a precursor to the formation of ammonium nitrate. Thus, focusing on reducing NOx emissions from mobile sources operating in California yields improvements in visibility for this planning period. During consultation with clean air agencies in the western region, our neighboring states were supportive of California's focus on mobile source NOx emissions reductions.

Again, regional haze planning is an iterative process. As NOx emissions are reduced, the pollutants driving visibility impairment will change. The iterative process laid out for regional haze planning allows states to make informed planning decisions, supported by science, and adjust strategies as needed for each planning period.

5. *NPS recommends that CARB include emission inventory data supporting exemption determinations in the SIP for transparency.*

This recommendation is in reference to device-level stationary source information CARB staff considered during the screening of stationary sources for reasonable progress analysis.

Stationary sources in California are permitted through local air districts. However, CARB has developed a number of tools for stakeholders to access information about stationary sources operating in California. CARB's pollution mapping tool[82] is an interactive platform that enables users to locate, view, and analyze emissions from large facilities in California. CARB's facility search engine is a tool[83] that can be used to query emissions data from facilities for a given inventory reporting year. This tool pulls data from the California Emissions Inventory Data Analysis and Reporting System (CEIDARS), which is a database management system developed to track statewide emissions. Device level emissions inventory information considered during the screening process was pulled from CEIDARS. Summary tables for the refineries, cement plants, and other combustion sources considered during step 3 of the stationary source screening process have been made available for download from CARB's regional haze website.[84]

6. *NPS recommends that the SIP would be strengthened by specifically addressing how the BARCT control determinations will satisfy the four statutory factors for each facility evaluated.*

CARB did not bring forward stationary sources subject to California's AB 617 for four factor analysis in this SIP because, under the expedited BARCT requirement they will be required to install more effective emission controls, if they are not already installed, prior to the end of the period covered by this SIP (2028). Initiating parallel and competing analyses of control options would have been an inefficient and costly step that would have potentially hindered steps being taken at the local level to address emissions from these sources.

California's AB 617 required local air districts to review rules for stationary sources subject to these requirements and adopt an expedited schedule by January 1, 2019 for implementation of BARCT by December 31, 2023. The expedited BARCT schedules adopted by air districts are available on CARB's website.[85]

The scale and pace of the work being completed by local air districts to meet the expedited BARCT requirement varies depending on the extent of air quality challenges and the subject facilities in their jurisdiction. CARB will provide an update on the implementation of the AB 617 expedited BARCT requirements as they relate to regional haze in the next progress report. As part of this update, CARB will assess the benefits and discuss the type of controls initiated and if changes to the haze strategy to further address emissions from stationary sources are warranted at that time.

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[82] https://ww3.arb.ca.gov/ei/tools/pollution_map/

[83] https://ww2.arb.ca.gov/our-work/programs/ab-2588-air-toxics-hot-spots/facility-search-tool

[84] https://ww2.arb.ca.gov/our-work/programs/california-state-implementation-plans/statewide-efforts/regional-haze

[85] https://ww2.arb.ca.gov/expedited-barct

7. *NPS recommends that CARB improve their draft SIP by providing additional documentation demonstrating unit-level emission reductions that AB 617 regulations will achieve or conducting full SO_2 and NOx four-factor analysis for eight refineries, six cement plants, five biomass facilities, and one mineral processing facility specifically identified.*

CARB's long-term strategy is focused on emissions reductions from the mobile source sector, which account for nearly 80 percent of NOx emissions in California. Projections indicate that the substantial emissions reductions that will be achieved during this planning period will improve visibility at all 29 Class I areas.

As stated in the response to comment six above, the scale and pace of the work being completed by local air districts to meet the expedited BARCT requirement varies depending on the extent of air quality challenges and the subject facilities in their jurisdiction. When these requirements go into place, the requirements are enforceable under State law and local permit conditions. CARB will provide an update on the implementation of the AB 617 expedited BARCT requirements as they relate to regional haze in the next progress report (due January 2025).

As detailed in Appendix G, the refineries, cement plants, and mineral processing facility referenced in the comments are subject to the expedited BARCT requirements of AB 617. The biomass facilities referenced in the comments are not subject to these requirements, but for the reasons laid out in Appendix G, it is reasonable to conclude that a full four factor analysis would likely find no further controls are necessary at this time for the purposes of regional haze.

Again, regional haze planning is an iterative process and at the next planning cycle, CARB will take a fresh look at visibility conditions, emissions driving visibility impairment, and develop evidence-based plans to ensure meaningful improvements in visibility conditions are achieved. If unit-level analyses are warranted in future planning periods, then those analyses will be developed at that time.

8. *NPS recommends that CARB conduct four-factor analyses for eight refinery facilities. Referencing the limits established for a new refinery approved for construction three miles outside of the entrance to the south unit of Theodore Roosevelt National Park in North Dakota, NPS recommends that SCR be evaluated for all boilers and heaters with greater than 27 mmBtu/hr heat input and that ultra-low NOx burners be evaluated for the smaller units.*

The feasibility and efficiency of control strategies can vary by facility. Control options for existing facilities can be different than those for new facilities. New facilities can include the latest controls as part of their design of the facility. Taking facility and jurisdiction specific considerations into account is necessary, particularly when considering control measures for existing facilities. Local air districts are best equipped to develop rules to regulate emissions of stationary sources located in their jurisdiction. The refineries referenced in this comment are subject to the expedited BARCT requirements of AB 617 in air districts that are in the process of developing and implementing rules that will address emissions from refineries. Further, these refineries are located in air districts with existing stationary source rules that are among the most stringent in the country. CARB will provide an update on the implementation of the AB 617 expedited BARCT requirements as they relate to regional haze in the next progress report (due January 2025).

9. *NPS recommends that CARB explain why water use associated with SNCR would be prohibitive, given the benefits of air pollution control.*

This comment is in reference to the discussion of the four statutory factors for potential control measures at Collins Pine Co that is provided in Appendix H.

In this discussion, CARB did not claim water use is prohibitive, but rather installation of SNCR would result in increased water demands at the facility. This change has relevant non-air quality environmental impacts associated with this control measure. Water demands for all sectors is a relevant consideration, particularly in a state where drought and drought related catastrophes are increasing in scale and intensity.

10. *In regard to Collins Pine Co., NPS recommends that CARB provide rationale for the conclusion that no additional reasonable emission control options were currently feasible for this facility.*

The four reasonable factors considered to reach this conclusion are described in Appendix H. Considering actual emissions and potential emissions benefits, the estimated annual cost effectiveness of an SNCR system was more than $24,000 per ton. Increased fuel demands were also expected as a result of increased fuel moisture loads caused by reagent injection. Further, the facility is located in an area where a federal disaster was declared in response to the 2021 Dixie Fire which burned more than a million acres. More than half of the facility's timber lands were burned by this wildfire resulting in an unprecedented number of dead and dying trees. Removal of these trees from the landscape is needed to facilitate restoration of a resilient forest system. Substantial efforts will be necessary for this facility and the surrounding community to recover from this disaster.

After considering the four reasonable progress factors, no additional reasonable controls are necessary at this time for the purposes of regional haze. However, as noted in previous responses, regional haze planning is an iterative process. At the next planning cycle, CARB will take a fresh look at visibility conditions, emissions driving visibility impairment, and develop evidence-based plans to ensure meaningful improvements in visibility conditions are achieved.

11. *NPS recommends that a complete four-factor analysis for woodwaste boilers will include an evaluation of selective catalytic reduction (SCR).*

SCR systems reduce NOx emissions with ammonia in the presence of a catalyst. The optimal temperature range for catalytic reduction is 650 to 850 ºF. Irreversible damage is caused to the catalyst when the pores are damaged. Ash from wood-fired boiler exhaust stream is abrasive and can damage catalyst pores. Sodium, potassium, phosphorus, and arsenic are naturally occurring catalyst poisons and found in wood.

As detailed in Appendix H, SCR was not considered a feasible retrofit control option for the Collins Pine Co. for the purposes of regional haze for this planning period because of the likelihood of catalyst deactivation through particulate plugging and catalyst poisoning, and exhaust gas temperatures out of the typical SCR operating ranges.

12. *NPS recommends that CARB require all technically feasible cost-effective controls identified through four factor analysis in order to address regional haze.*

CARB agrees with this comment. No additional reasonable controls for stationary facilities were identified by the analyses for this planning period. All four statutory factors and other place specific factors are relevant to control determinations. As detailed in Chapter 7 of this Regional Haze Plan, the emission reductions efforts projected for this planning period that result from implementation of regulatory measures in California are significant. Projections indicate that these emission reductions will reduce visibility impairment on a scale that keeps visibility in Class I areas throughout California on track to reach 2064 visibility goals.

CARB response to comments received from USFS

1. *USFS requests CARB consider using the prescribed fire glidepath adjustment developed using the "Future Fire Scenario 2," because these are more likely to accurately reflect the future acreage of wildland prescribed fire and effects on visibility.*

Technical guidance[86] prepared by U.S. EPA for development of this round of regional haze plans does not recommend changing prescribed fire emissions in future projections, given the uncertainty associated with future estimates. Following this guidance, prescribed fire is held constant for the endpoint adjustments developed by the WRAP and proposed for use by CARB in the Regional Haze Plan. This procedure ensures consistency with the calculation procedures used for the 2028 projections also developed by the WRAP for this planning period.

An extensive narrative is provided in Chapter 7 detailing CARB's efforts to support the use of prescribed fire, the need to increase prescribed fire treatment to mitigate the risk of catastrophic wildfires, and reference to the additional considerations for determining the future impacts of prescribed fire on regional haze metrics including the alternative adjustment proposed by USFS. Given that regional haze planning is an iterative process, updates to endpoint adjustments will be made in subsequent implementation periods.

2. *USFS prefers the inclusion of SOx emissions to better assess potential control strategies or a more detailed discussion on the reasoning used to determine the exclusion of SOx emissions. Noting that any further reductions will only further improve visibility in Class I areas and point source reductions will have the added benefit of reducing pollution near point sources.*

The technical basis for CARB's focus on NOx emissions in the long-term strategy for this round of regional haze planning relies on information from visibility monitoring data, state and regional emissions inventories, regional photochemical modeling, and source apportionment analyses (see also Figure I-1 above). For this planning period, the implementation of emission control measures detailed in Chapter 7 will yield substantial emissions reductions statewide and visibility metrics are projected to improve as a result of these reductions, keeping Class I areas on track to meet 2064 visibility targets.

CARB agrees that emission reductions from point (stationary) sources will reduce near-source emissions. Local air districts regulate emissions from point sources in California.

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[86] https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

Many local air districts are implementing strategies to reduce near-source emissions. Some of these efforts include actions to support implementation of the expedited BARCT requirements of AB 617 as well as actions to address indirect source emissions such as those from warehouses and new developments. Emissions reductions associated with these efforts will be reflected in emission inventories associated with regional haze plans developed for successive planning periods.

Regional haze planning is an iterative process. For each planning period, CARB will take a fresh look at visibility conditions, emissions contributing to visibility impairment, and ensure a strategy is in place that will yield meaningful improvements in visibility. As emissions are reduced, the pollutants driving visibility impairment will change. The iterative process laid out for regional haze planning allows states to make informed planning decisions, supported by science, and adjust strategies as needed.

3. *USFS suggest including SOx emissions and additional analysis to inform potential changes in emission sources that may otherwise be overlooked, citing the example of increased wait times for ships at the Port of Los Angeles and emissions that result.*

The COVID-19 pandemic has affected sectors around the world. Labor shortages, equipment shortages, changes to consumer demands, and changes to the supply chain resulting from the pandemic did lead to congestion at California's ports. The air quality impact of increased emissions associated with this increased congestion has been the subject of recent analyses by CARB staff.[87] These analyses indicate that the number of anchored vessels awaiting berthing assignments reached a peak in mid-November 2021. A new queuing system was implemented by the Pacific Maritime Management Services in mid-November 2021 that allows vessels to wait in designated areas 150 miles offshore, slow transit speeds across the Pacific to arrive closer to designated arrival date or wait in other designated areas. Vessel congestion has decreased since November 2021 when the new queuing system was implemented and therefore, port congestion is not expected to represent a permanent change in that emissions source.

Emissions from ocean-going vessels (OGV) have a measurable impact on air quality in California. While California does not have authority to set emissions standards for OGVs, CARB does require the use of low sulfur fuels when vessels are operating in California waters. Federal action to address emissions from OGVs could bolster CARB's efforts and accelerate the pace of emission reductions.

[87] https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/msei-documentation-port-congestion-impacts

Given the iterative planning process laid out in the Regional Haze Rule, CARB will take a fresh look at monitoring data and emissions contributing to visibility conditions during successive planning periods. CARB will continue take an evidence-based approach to plan development relying on the best available monitoring, inventory, and modeling data available. Strategies for making meaningful progress towards 2064 visibility will be adjusted as needed in future regional haze plans.

Comment Letters Received from Federal Land Managers

National Park Service (NPS) Regional Haze SIP feedback for the California Air Resources Board

April 11, 2022

Contents

1 Executive Summary

The National Park Service (NPS) appreciates the opportunity to review the draft of *California's Regional Haze Plan for the Second Implementation Period*. On April 7, 2022, staff from the NPS Air Resources Division (ARD); NPS Interior Regions 8, 9, 10, and 12; and NPS-managed Class I areas hosted a regional haze SIP review consultation meeting with California Air Resources Board (CARB) staff to discuss NPS conclusions and recommendations for the draft California Regional Haze State Implementation Plan (SIP). The NPS provides the following technical recommendations to strengthen the California draft SIP which were discussed during our consultation meeting and detailed in this document.

This technical feedback document provides:

- Review of NPS Class I areas in California (Section 2)
- Overarching feedback (Section 3)
    - Significance of California point sources
    - Exclusion of SO_2 from source selection and four factor analyses
        - The NPS recommends that CARB include SO_2 point source emissions in source selection and four factor analyses.
    - Source selection and screening feedback
        - The NPS recommends that for sources screened from analysis based on AB 617, CARB can improve the SIP by providing additional emission unit documentation or conducting four factor analyses as warranted.
- Feedback on Specific Sources Exempted from four-factor analysis (Section 4)
    - Refineries
        - The NPS recommends CARB complete a four-factor analysis or provide additional documentation for eight of the refineries originally selected for four-factor review.
    - Cement plants
        - The NPS recommends CARB complete a four-factor analysis or provide additional documentation for six cement plants originally selected for four-factor review.
    - Woodwaste boiler facilities
        - The NPS recommends four factor analysis or additional documentation for five woodwaste boiler facilities originally selected for four factor review.
    - Other facilities
        - The NPS recommends CARB complete a four-factor analysis or provide additional documentation for one chemical manufacturing facility originally selected for four factor review.
- Specific four-factor review of Collins Pine - Chester (Section 5)
    - NPS review finds that SNCR and SCR may both be technically feasible and are both likely cost-effective for reducing NOx emissions. The NPS recommends that California require the most stringent technically feasible, cost-effective

controls identified through four-factor analysis to reduce haze causing emissions in this planning period.

The NPS appreciates that California has unique authority under the CAA to implement mobile source emission reduction measures and is using this authority to reduce haze causing NO_x emission in this planning period. In addition, the NPS acknowledges California's point source NO_x reduction programs that will address nonattainment with the National Ambient Air Quality Standards (NAAQS). As the draft regional haze SIP highlights, reducing NO_x emissions through these programs will have co-benefits, including reduction of ammonium nitrate, a significant component of haze in California Class I areas. Yet, significant additional emission reductions will be necessary before the ultimate visibility goal of no human caused visibility impairment is realized. It is with this in mind that we provide the enclosed conclusions and recommendations.

Visibility improvement in Class I areas depends on the cumulative effects of regional emission reductions. CARB has an opportunity through the Regional Haze SIP to identify and require emission reductions that will reduce haze affecting NPS-managed Class I areas in California and beyond the state's borders. By focusing exclusively on mobile source NO_x emissions and deferring controls to other air pollution control programs the current draft SIP misses significant opportunities to specifically address haze. Further, this approach removes the NPS ability as a Federal Land Manager (FLM) to contribute substantively to haze planning. The NPS works with states across the country on haze planning and takes this once-in-a-decade chance to contribute expertise and make a difference for clear views in our Class I areas very seriously. The NPS looks forward to working with CARB to ensure clean air and clear views into the future and welcomes the opportunity for further dialogue as California progresses to a final SIP revision.

2 NPS Class I Areas in California

As CARB shares in the draft SIP:

> *National parks and wilderness areas in California are known for their extensive vistas and striking views of the natural landscape.*

The 1977 Clean Air Act Amendments designated 29 of these wilderness areas and national parks as mandatory federal Class I areas for visibility protection. The National Park Service (NPS) is responsible for protecting and preserving visibility in nine of these Class I areas *"…for the enjoyment of future generations."*

Two distinct desert ecosystems, the Mojave and the Colorado, come together in **Joshua Tree National Park**. A fascinating variety of plants and animals make their homes in a land sculpted by strong winds and occasional torrents of rain. Dark night skies, a rich cultural history, and surreal geologic features add to the wonder of this vast wilderness in southern California.

Lassen Volcanic National Park is home to steaming fumaroles, meadows freckled with wildflowers, clear mountain lakes, and numerous volcanoes. Jagged peaks tell the story of its eruptive past while hot water continues to shape the land.

Lava Beds National Monument is a land of turmoil, both geological and historical. Over the last half-million years, volcanic eruptions on the Medicine Lake shield volcano have created a rugged landscape dotted with diverse volcanic features. The park includes more than 800 caves, Native American rock art sites, and historic battlefields.

Some 23 million years ago multiple volcanoes erupted, flowed, and slid to form what would become **Pinnacles National Park**. What remains is a unique landscape. Travelers journey through chaparral, oak woodlands, and canyon bottoms. Hikers enter rare talus caves and emerge to towering rock spires teeming with life: prairie and peregrine falcons, golden eagles, and the inspiring California condor.

From its thunderous ocean breakers crashing against rocky headlands and expansive sand beaches to its open grasslands, brushy hillsides, and forested ridges, **Point Reyes National Seashore** offers visitors over 1500 species of plants and animals to discover. Home to several cultures over thousands of years, the Seashore preserves a tapestry of stories and interactions of people.

Most people know **Redwood National and State Parks** as home to the tallest trees on Earth. But the Parks also protect vast prairies, oak woodlands, wild rivers, and 40 miles of rugged coastline. People have lived in this verdant landscape since time immemorial. Together, the National Park Service and California State Parks are managing and restoring these lands for the inspiration, enjoyment, and education of all.

Huge mountains, rugged foothills, deep canyons, vast caverns, and the world's largest trees exemplify the diversity of landscapes, life, and beauty in **Sequoia and Kings Canyon National Parks**. Our ancient giant sequoias may seem invincible, but, as recent events have shown, they, too are vulnerable.

Not just a great valley, but a shrine to human foresight, the strength of granite, the power of glaciers, the persistence of life, and the tranquility of the High Sierra. First protected in 1864, **Yosemite National Park** is best known for its waterfalls, but within its nearly 1,200 square miles, you can find deep valleys, grand meadows, ancient giant sequoias, a vast wilderness area, and much more.

3 Overarching Feedback

In the draft SIP CARB identifies four measures targeting on-road mobile source emissions as necessary to ensure reasonable progress is made in Class I areas affected by emissions from California. California has significant NO_x emissions associated with mobile sources and the unique authority to address these emissions at the state level. The NPS appreciates the extensive work CARB has invested in reducing mobile source emissions through current and planned regulation as mobile sources are the largest source of NO_x emissions in the state. Nevertheless, emissions from California's stationary point sources are also significant. The NPS recommends that CARB amend the draft SIP and include additional point source four-factor analyses in the reasonable progress determinations that:

1. Assess opportunities to address haze causing SO_2 emissions.
2. Assess opportunities to address haze causing NO_x emissions or thoroughly document rational for screening individual emission units from full analysis.

3.1 Significance of California Point Sources

The 2017 National Emissions Inventory (NEI) values for California's stationary source annual emissions in tons/year (tpy) and nationwide rankings for visibility-impairing pollutants are shown in the table below.

Table 1. California 2017 NEI emissions and ranking compared with other states.

NH3 (tpy)	NH_3 (rank)	NO_x (tpy)	NO_x (rank)	PM_{10} (tpy)	PM_{10} (rank)	PM_{25} (tpy)	PM_{25} (rank)	SO_2 (tpy)	SO_2 (rank)
8,447	2	68,517	13	27,255	4	14,541	7	15,541	29

In terms of statewide point source emissions, in 2017, California was nationally ranked the 13th highest emitting state for NO_x emissions, the 29th highest emitting state for SO_2 emissions, the second highest for ammonia and the fourth highest for particulate when ranked against all states nationwide.

California stationary source SO_2 and NO_x emissions rank even higher when compared among the Western Regional Air Partnership (WRAP)[1] region states:

- California stationary source NO_x:
  - #2 for NO_x emissions in the Repbase2 scenario
  - #1 for NO_x emissions in the 2028OTBa2 future year scenario
- California stationary source SO_2:
  - #6 for SO_2 emissions in the Repbase2 scenario
  - #3 for SO_2 emissions in the 2028OTBa2 future year scenario

[1] WRAP includes AZ, CA, CO, ID, MT, ND, NM, NV, OR, SD, UT, WA, WY plus several tribes.

Table 2. WRAP modeled base and 2028 projected NO_x emissions for the "on the books" OTB scenario by state

State	RepBase2 NO_x		2028OTBa2 NO_x		Point NO_x Emissions Change 2028OTB minus Repbase2
	All Point Sources TPY (NonEGU + EGU + Oil & Gas Point)	Point Rank	All Point Sources 2028 TPY (NonEGU + EGU + Oil & Gas Point)	Point Rank	
California	67,355	2	78,918	1	+ 11,563
New Mexico	51,244	6	61,077	2	+ 9,833
Wyoming	69,663	1	56,967	3	-12,696
Utah	59,578	3	46,095	4	-13,483
Colorado	54,766	4	46,040	5	-8,726
North Dakota	43,408	7	41,235	6	-2173
Arizona	52,039	5	32,140	7	-19,899
Washington	30,430	8	23,689	8	-6,741
Montana	26,688	9	19,967	9	-6,721
Oregon	18,368	10	16,078	10	-2,290
Nevada	12,654	11	12,213	11	-441
Idaho	9,884	12	9,743	12	-141
South Dakota	3,431	13	3,509	13	+ 78

Table 3. WRAP modeled base and 2028 projected SO_2 emissions for the "on the books" OTB scenario by state

State	RepBase2 SO_2		2028OTBa2 SO_2		Point SO_2 Emissions Change 2028OTB minus Repbase2
	All Point Sources TPY (NonEGU + EGU + Oil & Gas Point)	Point Rank	All Point Sources 2028 TPY (NonEGU + EGU + Oil & Gas Point)	Point Rank	
North Dakota	47,993	1	44,632	1	-3,361
Wyoming	47,974	2	37,622	2	-10,352
California	14,416	6	16,458	3	+ 2,042
New Mexico	12,933	9	15,949	4	+ 3,016
Arizona	40,886	3	13,801	5	-27,085
Colorado	15,282	5	13,136	6	-2,146
Utah	14,304	7	12,838	7	-1,466
Washington	14,111	8	12,610	8	-1,501
Montana	16,781	4	12,061	9	-4,720
Idaho	4,551	12	4,096	10	-455
Nevada	6,446	11	3,893	11	-2,553
Oregon	9,997	10	2,618	12	-7,379
South Dakota	662	13	662	13	0

The WRAP Repbase2 and 2028OTBa2 emission scenarios were selected for comparison, as these are the scenarios for which modeling results are documented and reported in the draft California SIP. The emission inventories show that California is one of the top emitters in the western region for stationary sources. Current and projected SO_2 and NO_x emissions from California point sources exceed those in most other WRAP states. This is particularly important when considering that California is upwind of the remaining WRAP region.

3.2 Exclusion of SO_2

The NPS recommends that all states consider opportunities to reduce both NO_x and SO_2 emissions from stationary sources as part of regional haze planning. This is consistent with the EPA clarification memo recommendations[2] and is supported by recent visibility monitoring data in California. Additionally, the CARB rationale for excluding SO_2 was based on modeling information that is known to underpredict the importance of ammonium sulfate.

3.2.1 SO_2 contributions to Visibility Impairment in California's Class I areas

Data from 17 monitoring sites operated by the Interagency Monitoring of PROtected Visibility Environments (IMPROVE) Network are used track visibility conditions in California's Class I areas. (One monitor may represent multiple Class I areas.) Recent results of that monitoring are shown below.

[2] EPA July 2021 Clarification Memo, Section 2.2: "Consistent with the first planning period, EPA generally expects that each state will analyze sulfur dioxide (SO2) and nitrogen oxide (NOx) in selecting sources and determining control measures. In nearly all Class I areas, the largest particulate matter (PM) components of anthropogenic visibility impairment are sulfate and nitrate, caused primarily by PM precursors SO2 and NOx, respectively. 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, especially if the state considered both these pollutants in the first planning period."

Table 4. Average light extinction from ammonium sulfate and ammonium nitrate on most impaired days at California Class I area IMPROVE monitors (2015-2019).

CA Region	IMPROVE Site	Class I Area	IMPROVE 2015-2019 Most Impaired Days Avg		
			Sulfate (Mm-1)*	Nitrate (Mm-1)*	Total (Mm-1)*
Northern	LABE1	Lava Beds National Monument South Warner Wilderness Area	4.7	1.5	16.2
Northern	REDW1	Redwood National Park	10.2	2.6	24.2
Northern	TRIN1	Marble Mountain Wilderness Area Yolla Bolly-Middle Eel Wilderness Area	6.1	2.9	19.5
Northern	LAVO1	Thousand Lakes Wilderness Area Lassen Volcanic National Park Caribou Wilderness Area	4.9	1.7	18.1
Northern	BLIS1	Desolation Wilderness Area Mokelumne Wilderness Area	4.3	1.3	14.6
Northern	PORE1	Point Reyes National Seashore	8.8	14.8	38.5
Northern	YOSE1	Emigrant Wilderness Area Yosemite National Park	7.0	2.9	23.1
Central	HOOV1	Hoover Wilderness Area	4.0	1.1	13.1
Central	KAIS1	Ansel Adams Wilderness Area John Muir Wilderness Area Kaiser Wilderness Area	6.8	3.6	22.2
Central	PINN1	Pinnacles National Park Ventana Wilderness Area	8.5	7.5	30.9
Central	SEQU1	Kings Canyon National Park Sequoia National Park	13.3	13.4	50.5
Central	RAFA1	San Rafael Wilderness Area	11.2	6.2	31.5
Southern	DOME1	Domeland Wilderness Area	9.9	5.8	35.5
Southern	SAGA1	San Gabriel Wilderness Area Cucamonga Wilderness Area	7.5	9.8	28.0
Southern	SAGO1	San Gorgonio Wilderness Area San Jacinto Wilderness Area	6.4	14.0	32.5
Southern	JOSH1	Joshua Tree Wilderness Area	7.3	6.6	26.3
Southern	AGTI	Agua Tibia Wilderness Area	13.8	9.0	39.7

* Light extinction is measured in units of inverse megameters (Mm-1)

IMPROVE data show that the impact of ammonium sulfate (yellow highlights) exceeds the impact of ammonium nitrate (orange highlights) at 13 of the 17 monitoring sites representing California Class I areas in recent years. This demonstrates that SO_2, a precursor emission that leads to ammonium sulfate formation, is one of the most significant contributors to visibility impairment in the California NPS Class I areas.

3.2.2 Interpretation of SO_2 Modeling Results

Regional photochemical modeling to support development of this Regional Haze Plan was conducted by the WRAP. CARB excluded SO_2/sulfate from its regional haze plan based on interpretation of the CAMx model results provided by WRAP.[3] CARB concluded that emissions of SO_2 from U.S. stationary sources did not contribute significantly to visibility impairment at any Class I Area in or near California and therefore did not consider SO_2 in their source screening and analysis process.

NPS observes that:

1. California is home to several large SO_2 emission sources (see Section 3.1),
2. Sulfate is a significant contributor to visibility impairment in the California Class I areas (see Section 3.2.1),
3. California is a contributor to sulfate impairment within the state and is upwind of the WRAP region (see below) and,
4. Modeling results underpredict sulfate impacts in the NPS California Class I areas (see below).

The CAMx model performance evaluation shows a general under-prediction of sulfate extinction for six of eight sites representing NPS Class I areas in California. As an illustration of this, the table below compares of CAMx model results for sulfate in 2014 to IMPROVE 2014 sulfate measurements and shows that CAMx underestimates annual sulfate impacts in six of the monitors representing NPS Class I areas (by as much as 68%) and overestimates in two of the NPS Class I areas (by as much as 186%).

[3] CAMx is an acronym that stands for Comprehensive Air Quality Model with eXtensions. CAMx combines regional emissions inventory information with information on atmospheric chemistry and meteorology to determine the amount of haze pollution that was or will be formed in a particular location on a particular day.

Table 5. IMPROVE and CAMx comparison; Sulfate model performance.

NPS Class I areas in CA	Sulfate (Mm-1)		IMPROVE 2014 minus WRAP 2014 & Percent of Monitored SO_4 Predicted by the Model	
	IMPROVE	CAMx		
	2014	2014v2	(Mm-1)	(%)
JOSH1	7.73	4.39	3.34	43%
LABE1	7.17	5.38	1.79	25%
LAVO1	6.90	4.89	2.01	29%
PINN1	9.11	8.32	0.79	9%
PORE1	10.70	19.88	-9.18	-86%
REDW1	12.66	36.23	-23.57	-186%
SEQU1[4]	10.69	3.43	7.26	68%
YOSE1	6.94	3.55	3.39	49%

Even with the underestimated SO_4 in the CAMx modeling, the model showed that sulfate exceeded 10% of total visibility impairment in at least five of the eight California NPS sites modeled.[5] In addition, the source apportionment results provided in Figure 4-3 of the SIP show that U.S. anthropogenic sources currently account for approximately 20% of the *total sulfate* impairment at PORE1, SEQU1, and JOSH1 (as well as several USFS Class I areas). When considering just the anthropogenic component of sulfate haze, the WRAP 2028 on the books (OTB) projection predicts that U.S. anthropogenic sources account for up to 52% of the total anthropogenic sulfate impairment in the NPS Class I areas.

Table 6. WRAP 2028 OTB projection of U.S. anthropogenic impairment at Class I areas from ammonium sulfate

Site Code	Site Name	Parameter	International Anthropogenic Sources Mm-1	US Anthropogenic Sources Mm-1	Total Anthro Mm-1	US Sources % of Total Anthro Impairment
JOSH1	Joshua Tree NP	AmmSO4	0.41207	0.12057	0.53264	23%
LABE1	Lava Beds NM	AmmSO4	0.76798	0.05532	0.8233	7%
LAVO1	Lassen Volcanic NP	AmmSO4	0.56901	0.06422	0.63323	10%
PINN1	Pinnacles NM	AmmSO4	0.49561	0.17015	0.66576	26%
PORE1	Point Reyes NS	AmmSO4	0.5797	0.61628	1.19598	52%
REDW1	Redwood NP	AmmSO4	0.77473	0.21759	0.99232	22%
SEQU1	Sequoia NP	AmmSO4	0.39793	0.10358	0.50151	21%
YOSE1	Yosemite NP	AmmSO4	0.41268	0.07227	0.48495	15%

Finally, California is located upwind of the remaining continental U.S. and is a significant contributor to visibility impairment in downwind Class I areas in the WRAP region. For

[4] The SEQU1 IMPROVE monitor is representative of visibility conditions for both Sequoia and Kings Canyon National Parks.
[5] CARB *Figure 4-3: Ammonium Sulfate Source Apportionment for the 2014-2018 Most Impaired Days*

example, WRAP 2028 OTBa2 modeling show that California industrial point sources (nonEGUs) make the most significant contribution to predicted 2028 anthropogenic sulfate impairment of all U.S. anthropogenic source categories in Zion, Bryce Canyon, and Grand Canyon National Parks. Based on IMPROVE monitoring data, ammonium sulfate is the most significant component of haze in Zion, Bryce Canyon and Grand Canyon National Parks on the 20% most impaired days. NPS recommends that CARB address SO_2 emissions from their stationary point sources because of their contributions to impairment in both in-state and out-of-state NPS Class I areas.

Figures 2 and 3 show the geographic location of some of the more significant stationary source regions in California, including the Bay Area and Southern California/Los Angeles. Individual point sources are labeled and mapped according to their total 2017 SO_2 plus NO_x emissions (Q) and the relative proportion of SO_2 (yellow) versus NO_x (red) emissions for each facility. Only facilities with a Q greater than 100 are mapped. The maps demonstrate that there are still significant stationary sources of SO_2 and NO_x emissions in California to be addressed. The need to address NO_x emissions from California stationary sources is discussed in Section 3.3 below.

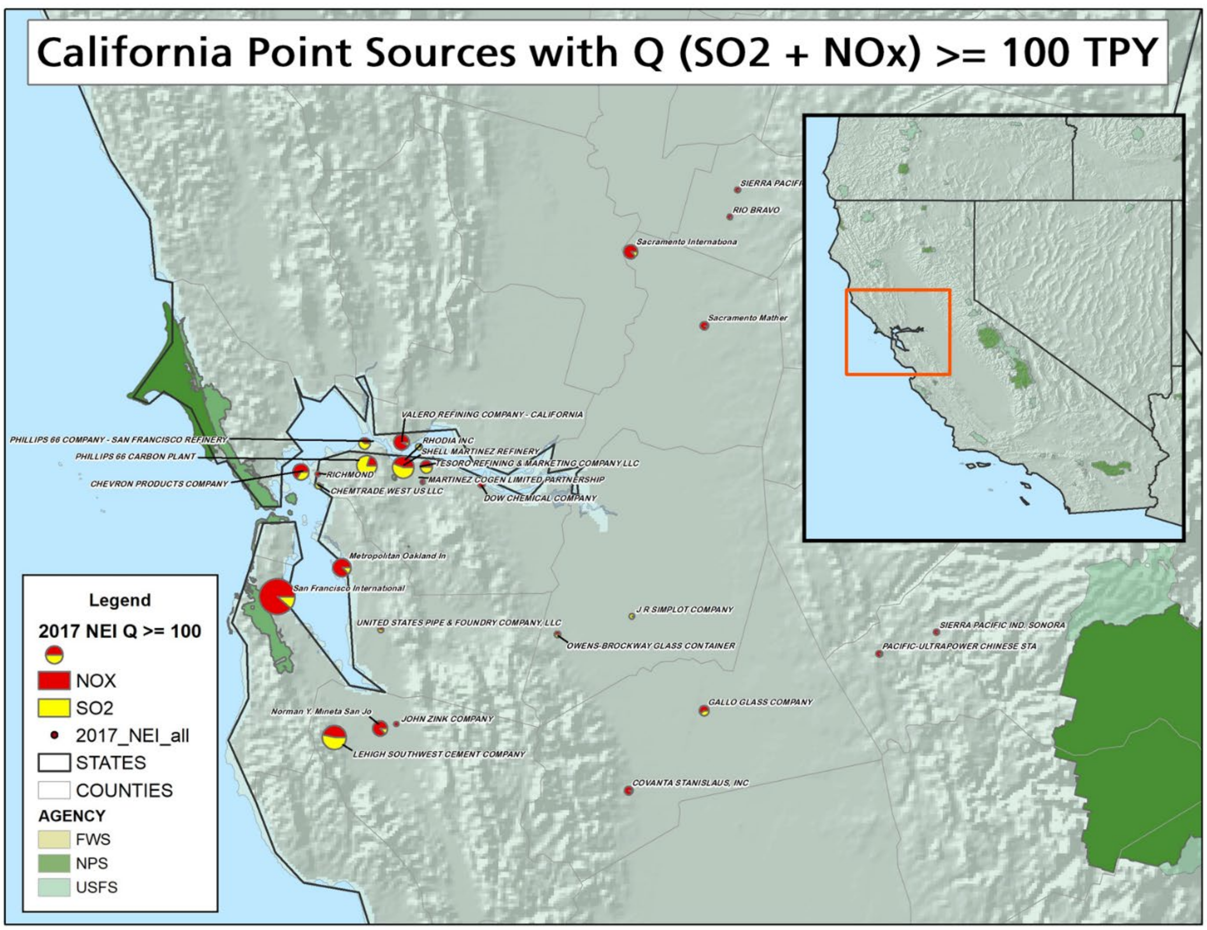

Figure 1. Map of San Francisco Bay area facilities with emissions (Q) greater than 100 tons/year in 2017. Proportional pie charts show the NO_x emissions in red and SO_2 emissions in yellow.

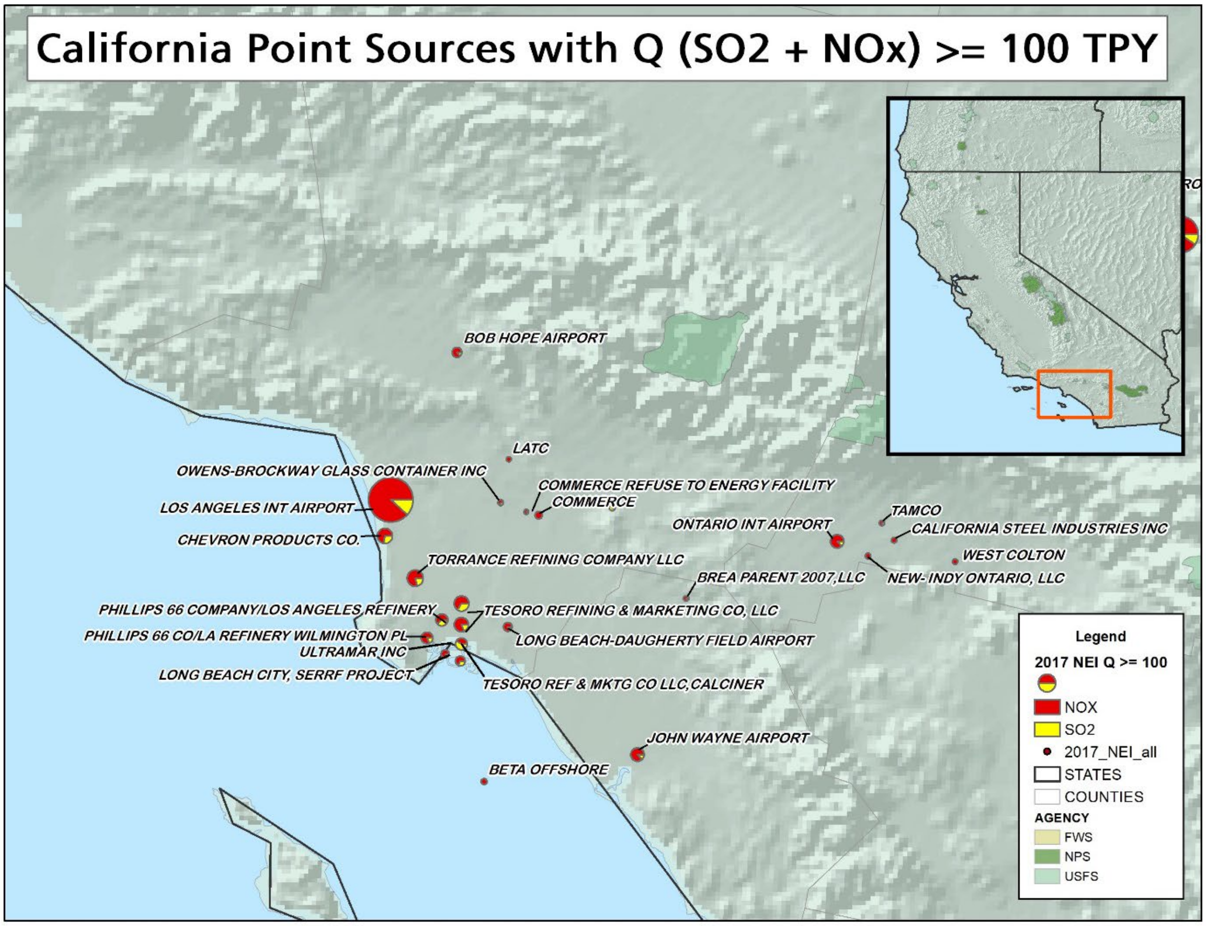

Figure 2. Map of Los Angeles area facilities with emissions (Q) greater than 100 tons/year in 2017. Proportional pie charts show the NO_x emissions in red and SO_2 emissions in yellow.

3.3 Source Selection & Screening

CARB used a NO_x emissions over distance (Q/d) threshold of 5 as an initial screening tool to identify stationary sources for evaluation of potential emission controls based on the four statutory factors identified in §7491 (g)(1) of the Clean Air Act. This initial step identified 42 facilities. All but one of these facilities were excluded from four-factor analyses in subsequent screening steps based on A) device level emission inventories and B) review of existing controls, planned controls, and proposed operational changes.

3.3.1 Q/d of 5

Q/d is a widely used method of screening for potential visibility effects on Class I areas. California's NO_x Q/d threshold of 5 is less rigorous than the Q/d threshold selected by several other WRAP regions states. For instance, Idaho used a Q/d of 2 and Oregon used a Q/d of 5 where Q is the sum of multiple visibility impairing pollutants (PM_{10}, NO_x, and SO_2). However, NPS review finds that, for this round of haze planning in California, a threshold of 5 for an individual pollutant was sufficiently rigorous to identify a reasonable number of sources for analysis in California. The NPS continues to recommend that facilities with a Q/d of 5 for either NO_x or SO_2 warrant full four factor analysis for the pollutant or pollutants that meets that threshold.

3.3.2 Screening based on device level emission inventories

With respect to stationary point source screening based on device level emissions information, the NPS recommends that CARB include emission inventory data supporting exemption determinations in the SIP for transparency. In general, the NPS supports exclusion of sources for which emission control opportunities are minimal and requests that emission information supporting such a determination be included in the SIP rationale. In addition, the NPS has not encouraged any state to pursue four factor analyses at airports because of minimal emission control opportunities at airports for states to pursue. The NPS concludes that additional device-level emissions information is not necessary for airports.

3.3.3 Screening based on review of existing controls, planned controls, and proposed operational changes (Deference to BARCT and AB 617)

In the draft SIP CARB states that:

> *…California views the implementation of BARCT level controls as equivalent to reasonable controls for regional haze planning purposes. Implementation of additional controls measures due to AB 617 will have a measurable impact on reducing air pollution, including reduction of particulate matter and particulate matter precursors that impair visibility. Stationary facilities implementing new control measures to meet the expedited BARCT requirements of AB 617 will have measures in place prior to 2028, the end of the second implementation period for regional haze programs, and measures will be enforceable under State law and local rules.*
>
> *For each of the facilities moved forward to this third screening step, operating permits were reviewed as well as plans for additional emission controls or proposed operational changes. Facilities were excluded at this step if the information about existing controls, planned controls, or planned operational changes indicated that a full four factor analysis would likely result in the conclusion that reasonable controls are in place.*

California's screening of sources from four factor analysis based on review of existing controls, planned controls, and proposed operational changes raises several concerns: (1) CARB needs to provide sufficient detail in the draft SIP to support the determination to exclude sources from analysis and (2) deference to alternate regulatory programs removes the NPS' ability as a Federal Land Manager (FLM) to contribute substantively to haze planning. Typically, Regional Haze SIPs document the feasibility of specific emission reductions strategies for individual units with a four-factor analysis or provide a detailed technical demonstration that such an analysis is not warranted.

BARCT requirements are designed to address nonattainment issues (ozone and particulate matter) rather than regional haze. It is unclear whether potential emission reductions achieved under the expedited BARCT requirements of AB 617 will be equivalent to reductions that would be achieved under reasonable progress. Furthermore, the timing of the BARCT process is out of sync with regional haze planning and in most cases, the future BARCT controls have not been fully analyzed. Finally, it is unclear whether the decision criteria for BARCT determinations will satisfy the four statutory factors required by the CAA for reasonable progress analyses.

Documenting the specific emission units that will be subject to BARCT at the affected facilities and identifying the current and proposed control technologies, control efficiencies, and emission reductions that will be achieved for individual emissions units would allow for robust technical review and provide an added level of certainty to understanding potential future emissions. Further, NPS recommends that the SIP would be strengthened by specifically addressing how the BARCT control determinations will satisfy the four statutory factors for each facility evaluated.

FLM engagement is an important component of the regional haze planning process and is required under the Clean Air Act. Deferring control determinations to the BARCT/AB 617 process, without providing the requisite level of detail necessary to evaluate controls achieved through that program, effectively removes the FLM consultation process from the control technology determinations. This undermines the FLM obligation to provide substantive feedback and eliminates the opportunity for FLMs to comment on the final long-term strategy and reasonable progress determinations affecting the Class I areas entrusted to their management.

The NPS recommends that CARB improve their draft SIP by providing additional documentation demonstrating unit-level emission reductions that AB 617 regulations will achieve *or* conducting full SO_2 and NO_x four-factor analysis for the identified facilities. Specifically, based on information available in the draft SIP and in the public domain, the NPS recommends that full four-factor analyses for NO_x and/or SO_2 emission reduction opportunities are warranted at:

- 8 refineries
- 6 cement plants
- 5 biomass facilities
- 1 chemical manufacturing facility

Details of these recommendations are included in Section 4.

4 Sources Exempted from Four-Factor Analysis

4.1 Refineries

4.1.1 California Refinery Emissions

In 2017, refineries specifically excluded from four factor analysis Step 3 in the CARB screening process collectively emitted 7,530 tons of NO_x and 5,187 tons of SO_2. The table below reflects expected changes from those 2017 emissions.

Table 7. California Refinery 2017 Emissions Summary and Q/d analysis.

EIS Facility ID	Site Name	City	NO_x (tons)	SO_2 (tons)	Q	Distance to NPS Class I Area (km)	Q/d	NO_x Q/d	SO_2 Q/d	NPS Class I Area
6480811	TESORO REFINING & MARKETING COMPANY LLC	MARTINEZ	360	344	703	58	12.13	6.20	5.93	PORE
6530111	CHEVRON PRODUCTS COMPANY	RICHMOND	737	374	1,111	28	39.67	26.33	13.35	PORE
5812811	PHILLIPS 66 CARBON PLANT	RODEO				43				PORE
15733011	PHILLIPS 66 COMPANY - SAN FRANCISCO REFINERY					43				PORE
5812811, 15733011	Phillips 66 Rodeo Renewed Project	RODEO	210	295	505	43	11.74	4.88	6.86	PORE
6531011	SHELL MARTINEZ REFINERY	MARTINEZ	916	1,155	2,071	54	38.36	16.97	21.39	PORE
14217311	VALERO REFINING COMPANY - CALIFORNIA	BENICIA	1,013	95	1,108	52	21.31	19.48	1.83	PORE
4086111	CHEVRON PRODUCTS CO.	EL SEGUNDO	729	282	1,011	180	5.62	4.05	1.57	JOTR
5682211	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	CARSON	391	241	632	166	3.81	2.36	1.45	JOTR
6500611	PHILLIPS 66 CO/LA REFINERY	WILMINGTON	471	109	580	165	3.51	2.85	0.66	JOTR

EIS Facility ID	Site Name	City	NO_x (tons)	SO_2 (tons)	Q	Distance to NPS Class I Area (km)	Q/d	NO_x Q/d	SO_2 Q/d	NPS Class I Area
	WILMINGTON PL									
5682211, 6500611	Phillips 66 Carson + Wilmington		862	350	1,212	165	7.35	5.23	2.12	JOTR
4073511	TESORO REFINING & MARKETING CO, LLC	CARSON	661	339	1,000	166	6.03	3.98	2.04	JOTR
14055211	TESORO REFINING AND MARKETING CO, LLC	WILMINGTON	749	175	925	165	5.60	4.54	1.06	JOTR
4073511, 14055211	Tesoro Carson + Wilmington		1,410	515	1,925	165	11.67	8.55	3.12	JOTR
17922111	TORRANCE REFINING COMPANY LLC	TORRANCE	924	242	1,165	175	6.66	5.28	1.38	JOTR

Facilities highlighted in green have a NO_x or SO_2 Q/d >5

NPS recommends that CARB conduct four-factor analyses on eight refinery facilities (highlighted in green) with Q/d values > 5 for NO_x or SO_2 at a NPS Class I area. 2017 emissions from these eight facilities total 6,223 tons of NO_x and 2,167 tons of SO_2 recommended for review. For NO_x four factor analyses, NPS recommends that SCR be evaluated for all boilers and heaters with greater than 27 mmBtu/hr heat input, and that Ultra-Low-NO_x Burners be evaluated for the smaller units.[6]

Due to the absence of information on specific operations at these refineries, a preliminary NPS review compared their emissions on a per barrel of throughput basis to other refineries across the U.S.[7]

[6] The permit issued for Meridian Energy's Davis Refinery in North Dakota included limits based upon this level of control.

[7] NPS borrowed this approach and the data for refineries outside of California from Washington Ecology which is using this approach to aid in its evaluation of refineries in Washington.

Table 8. Comparison of California refinery emissions with other U.S. refinery emissions per barrel of throughput

State	Company	NO_x	SO_2	1,000	NO_x tpy/1,000	NO_x tpy/1,000	SO_2 tpy/1,000	SO_2 tpy/1,000
		tpy 2014	tpy	BPD	BPD	BPD (rank)	BPD	BPD (rank)
CA	Tesoro Refining & Marketing Company (Martinez)	360	344	48	7.494	4	7.161	2
CA	Chevron Products Company (Richmond)	737	374	257	2.866	22	1.453	14
CA	Rodeo Renewed Project	210	295	118	1.780	26	2.500	8
CA	Shell Martinez Refinery	916	1,155	157	5.838	10	7.356	1
CA	Valero Refining Company (Benicia)	1,013	95	170	5.959	9	0.560	21
CA	Chevron Products Co. (El Segundo)	729	282	290	2.515	25	0.972	18
CA	Phillips 66 Co/Los Angeles Refinery – Carson+Wilmington	862	350	139	6.203	11	2.516	7
CA	Tesoro Refining and Marketing Co. – Carson and Wilmington	1,410	515	363	3.885	15	1.418	15
CA	Torrance Refining (formerly ExxonMobil)	924	242	155	5.958	8	1.561	12
IL	ConocoPhillips Co	1,402	1,495	334	4.198	14	4.475	3
IL	Exxon Mobil Oil Corp	1,160	443	238	4.873	13	1.861	10
LA	Phillips 66 Co - Alliance Refinery	892	555	253	3.526	17	2.194	9
LA	Citgo Petroleum Corp - Lake Charles Manufacturing Complex	3,634	585	418	8.694	2	1.399	16
LA	Equilon Enterprises LLC - Shell Oil Products US Norco Refinery	1,626	226	225	7.227	6	1.004	17
LA	Marathon Petroleum Co LP - LA Refining Division - Garyville Refinery	1,470	376	564	2.606	24	0.666	20
LA	ExxonMobil Refinery & Supply Co - Baton Rouge Refinery	1,951	269	540	3.613	16	0.498	23

State	Company	NO_x	SO_2	1,000	NO_x tpy/1,000	NO_x tpy/1,000	SO_2 tpy/1,000	SO_2 tpy/1,000
		tpy 2014	tpy	BPD	BPD	BPD (rank)	BPD	BPD (rank)
TX	Baytown Refinery	1,815	1,606	584	3.109	18	2.751	5
TX	Galveston Bay Refinery	1,673	1,469	571	2.931	21	2.573	6
TX	Beaumont Refinery	1,783	676	365	4.886	12	1.851	11
TX	Port Arthur Refinery	1,828	323	603	3.031	19	0.536	22
TX	Deer Park Plant	1,495	181	500	2.990	20	0.362	24
WA	BP Cherry Point Refinery	1,918	808	242	7.926	3	3.339	4
WA	Shell Puget Sound Refinery	1,054	225	145	7.267	5	1.553	13
WA	Tesoro Northwest Company	1,971	80	119	16.561	1	0.670	19
WA	Phillips 66 Ferndale Refinery	674	38	105	6.419	7	0.362	25
WA	U.S. Oil & Refining Co	115	6	41	2.815	23	0.156	26
	Averages				5.349		1.767	

For NO_x emissions, four of the California refineries ranked among the top ten for tons/yr of emissions per 1,000 barrel per day (bpd) capacity. Five of the California refineries (orange highlight) also had NO_x emissions/1,000 bpd that exceed the sample average of 5.3.

For SO_2 emissions, four of the California refineries ranked among the top ten for tons/yr of emissions per 1,000 barrel per day (bpd) capacity—the top two are California refineries. Four of the California refineries (yellow highlight) also had SO_2 emissions/1,000 bpd that exceed the sample average of 1.8.

4.1.2 Specific Four Factor Analysis Recommendations

Tesoro Refining & Marketing Company (Facility ID: 6480811)

The Tesoro Refinery & Marketing Company in Martinez ranks #4 for NO_x emissions/barrel and #2 for SO_2 emissions/barrel; emissions/bpd are above average for both pollutants. Q/d for NO_x is 6.2 and for SO_2 is 5.3 at Point Reyes National Seashore (PORE). In February 2021, the company submitted a CEQA Notice of Preparation (NOP) requesting approval of a project proposal to convert the refinery to a renewable fuels facility. CARB did not provide specific information requested by the NPS regarding the Tesoro permit modification application. In the absence of this data and an estimate of future emissions, the NPS recommends a four-factor analysis for both NO_x and SO_2 because emissions/bpd are above average for both pollutants and Q/d for both pollutants exceed 5.

Chevron Products Company (Facility ID: 6530111)

The Chevron Products Company operates a petroleum refinery in Richmond that ranks #22 for NO_x emissions/barrel and #14 for SO_2 emissions/barrel. Emissions/bpd are below average for both pollutants. Q/d for NO_x is 26.3 and for SO_2 is 13.3 at Point Reyes National Seashore. A full four-factor analysis is recommended for NO_x and SO_2 because Q/d values exceed 5 for both pollutants.

Phillips 66 Carbon Plant (Facility ID: 5812811)

Phillips 66 San Francisco Refinery (Facility ID: 15733011)

The Rodeo Renewed Project affecting operations at the San Francisco Refinery and the Carbon Plant would result in a facility that ranks #26 for NO_x emissions/barrel and #8 for SO_2 emissions/barrel: SO_2/bpd is above average. Q/d for NO_x is 4.9 and for SO_2 is 6.9 at Point Reyes National Seashore. A full four-factor analysis is recommended for SO_2 because SO_2/bpd is above average and SO_2 Q/d exceeds 5.

Shell Martinez Refinery (Facility ID: 6531011)

The Shell Martinez Refinery ranks #10 for NO_x emissions/barrel and #1 across the U.S. for SO_2 emissions/barrel. Emissions/bpd are above average for both pollutants. Q/d for NO_x is 17 and for SO_2 is 21.4 at Point Reyes National Seashore. Full four-factor analyses are recommended for both NO_x and SO_2 because emissions of both NO_x and SO_2 are above average (emissions/bpd) and Q/d values exceed 5 for both pollutants.

Further, Appendix G notes that expedited BARCT requirements will only target *"condensable particulate matter"* and the district is only considering additional condensable PM controls for the Fluid Catalytic Cracking Unit (FCCU). The SIP Appendix notes that in 2017, *"95 percent of NOx emissions were from the process gas boilers."* The boilers are controlled under a 2001 consent decree, which is over twenty years old and warrants review.

Valero Refining Company (Facility ID: 14217311)

The Valero Refinery in Benicia ranks #9 for NO_x emissions/barrel and #21 for SO_2 emissions/barrel; emissions/bpd are above average for NO_x and below average for SO_2. Q/d for NO_x is 19.5 and for SO_2 is 1.8 at Point Reyes National Seashore. A full four-factor analysis is recommended for NO_x because emissions are above average (emissions/bpd) and Q/d exceeds 5.

Chevron Products Co. (Facility ID: 4086111)

The Chevron El Segundo Refinery ranks #25 for NO_x emissions/barrel and #18 for SO_2 emissions/barrel; emissions/bpd are below average for both pollutants. Q/d for NO_x is 4.0 and for SO_2 is 1.6 at Joshua Tree National Park. NPS concludes that further analysis is necessary.

Phillips 66 Co/Los Angeles Refinery – Carson (Facility ID: 5682211) And;

Phillips 66 Co/LA Refinery Wilmington (Facility ID: 6500611)

The Los Angeles Refinery comprises two linked facilities, five miles apart, in Carson and Wilmington. Carson processes crude oil, and Wilmington upgrades the intermediate products to finished products. The NPS requests that CARB provide detailed information on emissions, permit limits and control efficiencies for the emission units at these facilities. The combined Phillips 66 refineries rank #11 for NO_x emissions/barrel and #7 for SO_2 missions/barrel; emissions/bpd are below average for both pollutants. Q/d for NO_x is 5.2 and for SO_2 is 2.1 at Joshua Tree National Park. A full four-factor analysis is recommended for NO_x because Q/d exceeds 5.

Tesoro Refining and Marketing Co. – Carson and Wilmington

– Facility ID: 4073511 (Carson) & 14055211 (Wilmington)

The Tesoro Carson and Wilmington Refineries rank #15 for NO_x emissions/barrel and #15 for SO_2 missions/barrel; emissions/bpd are below average for both pollutants. Q/d for NO_x is 8.5 and for SO_2 is 3.1 at Joshua Tree National Park. The NPS requests that CARB provide detailed information on emissions, permit limits and control efficiencies for the emission units at these facilities. A full four-factor analysis is recommended for NO_x because Q/d exceeds 5.

Torrance Refining (formerly ExxonMobil) (Facility ID: 17922111)

The Torrance Refinery ranks #8 for NO_x emissions/barrel and #12 for SO_2 missions/barrel; emissions/bpd are above average for NO_x and below average for SO_2. The Torrance refinery Q/d for NO_x is 5.3 and for SO_2 is 1.4 at Joshua Tree National Park. The NPS requests that CARB provide detailed information on emissions, permit limits and control efficiencies for the emission units at these facilities. A full four-factor analysis is recommended for NO_x because emissions/bpd are above average, and Q/d exceeds 5.

4.2 Cement Plants

4.2.1 California Cement Plant Emissions

In 2017, cement plants specifically excluded by CARB in its Step 3 emitted 11,156 tons of NO_X and 3,227 tons of SO_2.

Table 9. California Cement Plant 2017 Emissions Summary and Q/d analysis.

EIS ID	Site Name and City	Hg (lb)	NO_x (tons)	NO_x (lb/ton clinker)	SO_2 (tons)	SO_2 (lb/ton clinker)	Distance to NPS Class I Area	NO_x Q/d	SO_2 Q/d	NPS Class I Area
7066411	LEHIGH SOUTHWEST CEMENT COMPANY--Cupertino	49.1	1,035	2.00	1,393	2.10	88	11.7	15.8	PORE
4789311	Cal Portland Mojave Plant-Mohave	4.6	1,013	2.50	457	1.70	150	6.8	3.0	SEQU

4841311	CEMEX - BLACK MOUNTAIN QUARRY PLANT-Apple Valley	270.4	5,420	1.95	569	0.35	86	63.0	6.6	JOTR
4921411	MITSUBISHI/CUSHENBURY PLANT-Lucerne Valley	72.7	1,944	2.80	344		49	39.7	7.0	JOTR
17924211	CALPORTLAND ORO GRANDE-Oro Grande	47.5	1,141	2.45	7		160	7.1	0.0	JOTR
1673211	LEHIGH SOUTHWEST CEMENT COMPANY-Redding	8.1	603	1.95	457	0.40	70	8.6	6.5	LAVO

Due to the absence of information on specific operations at these cement plants, NPS review compared emission limits (where available) on a per ton of clinker output basis. These kilns averaged 2.28 lb NO_x and 1.14 lb SO_2 per ton of clinker.

For NO_x emissions, three of the California cement plants had above-average limits (orange highlight) and all six also had NO_x Q/d values that exceeded 5 (orange highlight) at a NPS Class I area. Although it appears that these kilns are equipped with Selective Non-Catalytic Reduction (SNCR), this technology is typically capable of reducing NO_x emissions by about 40%. Due to the magnitude of the NO_x emissions and the high Q/d values, we recommend that Selective Catalytic Reduction (SCR) should be evaluated for all kilns at these facilities. Although SCR has seen limited use for cement kilns in the US so far, it has been/is being applied at the Lafarge Cement plant in Joppa, Il and at the CRH Opterra Zement's plant in Karsdorf, Germany and Holcim WestZement at its Beckum, Germany plant.

According to EPA's Control Cost Manual (CCM):

> *Today, SCR has been successfully implemented at seven European cement plants in Solnhofer, Germany (operated from 2001 until 2006), Bergamo, Italy (2006), Sarchi, Italy (2007), Mergelstetten, Germany (2010), Rohrdorf, Germany (2011), Mannersdorf, Austria (2012), and Rezatto, Italy (2015). As of 2015, there is only one cement plant in the U.S. that has installed an SCR. This SCR began operation in 2013 and is installed after an electrostatic precipitator. The control efficiency for the system is reported to be about 80 percent, which is consistent with SCR applications on European kilns.*

The CCM goes on to note that there may be *"...potential problems caused by high-dust levels and catalyst deactivation by high sulfur trioxide (SO3) concentrations from pyritic sulfur found in the raw materials used by U.S. cement plants."* Such technical feasibility concerns should be addressed as part of a proper four-factor analysis.[8]

[8] We included mercury (Hg) emissions in our table because, depending on the location of the SCR, its ability to ionize Hg to a form that can be captured by downstream emission controls could represent a co-benefit.

For SO_2 emissions, at least two of the California cement plants had above-average limits (yellow highlight) and four also had SO_2 Q/d values that exceeded 5 (yellow highlight) at a NPS Class I area. Potential SO_2 controls include Dry Sorbent Injection (DSI) and wet scrubbing.

Lehigh Southwest Cement Company (Facility ID: 7066411)

The California draft SIP reports 2019 NO_x emissions from this facility of 1,035 tons. This results in a Q/d value of 11.7 at Point Reyes National Seashore. Because SNCR cannot achieve the same level of NO_x reduction as SCR, NPS recommends that addition of SCR be considered in a four-factor analysis. Furthermore, because SO_2 emissions result in a Q/d value of 15.87 at Point Reyes National Seashore and because information on SO_2 controls is not readily available, the NPS recommends that addition of SO_2 controls be evaluated in a four-factor analysis.

Cal Portland Mojave Plant (Facility ID: 4789311)

NPS review of this facility finds that the Consent Decree limit is 1.7 lb NO_x/ton clinker with lime injection. Plant NO_x and SO_2 limits are above average. Because 2017 NO_x emissions result in a Q/d value of 6.8 at Sequoia and Kings Canyon National Parks, the NPS recommends that addition of SCR be considered in a four-factor analysis.

Cemex – Black Mountain Quarry (Facility ID: 4841311)

NPS requests that CARB provide information on the type of coal burned, production rate, and existing controls and control efficiencies for NO_x and SO_2 at this facility. These data are needed to support the SIP conclusion that no further controls are necessary. NPS review finds that the Consent Decree limits SO_2 to 0.35 lb/ton of clinker. Because 2017 NO_x and SO_2 emissions result in Q/d values of 63 and 6.6, respectively, at Joshua Tree National Park, the NPS recommends that four-factor analyses be conducted for both pollutants.

Mitsubishi Cement (Cushenberry Plant) (Facility ID: 4921411)

NPS requests that CARB provide information on the type of fuel that is burned, production rate, and existing controls and control efficiencies for NO_x and SO_2 at this facility. These data are needed to support the SIP conclusion that no further controls are necessary. NPS review finds that the NO_x emission limit for Mitsubishi Cement is the highest among the California cement kilns. Because 2017 NO_x and SO_2 emissions result in Q/d values of 39.7 and 7.0, respectively, at Joshua Tree National Park, the NPS recommends four-factor analysis for both pollutants.

Cal Portland Oro Grande (Facility ID: 17924211)

NPS requests that CARB provide information on the type of fuel burned, production rate, and existing controls and control efficiencies for NO_x and SO_2 at this facility. These data are needed to support the SIP conclusion that no further controls are necessary. The NO_x emission limit for Cal Portland Oro Grande is higher than average among the California cement kilns. Because 2017 NO_x emissions result in a Q/d value of 7.1 at Joshua Tree National Park, the NPS recommends four-factor analysis for NO_x.

Lehigh Southwest Cement Company (Facility ID: 1673211)

This facility is subject to a 2019 U.S. EPA Consent Decree limiting NO_x emissions to 1.95 lbs /ton clinker with combustion controls or SNCR within 24 months of the effective date of the consent decree. The Consent Decree also limits SO_2 to 0.4 lb/ton clinker based on “kiln inherent scrubbing.” The NPS requests that CARB provide information on current emissions, what type of fuel is burned, production rate, and existing controls and control efficiencies for NO_x and SO_2. These data are needed to support the SIP conclusion that no further controls are necessary. The NO_x emission limit at Lehigh Southwest Cement Company is higher than average among the California cement kilns. Because 2017 NO_x and SO_2 emissions result in Q/d values of 8.6 and 6.5, respectively, at Lassen Volcanic National Park, the NPS recommends four-factor analyses for both pollutants.

4.3 Woodwaste boiler facilities

The woodwaste-fired boilers excluded by CARB in Step 3 of source screening, appear to be controlled by SNCR which can typically achieve 20%–30% NO_x reduction. SCR, which can achieve 90% NO_x reduction, has been successfully applied to similar boilers. For example, Burgess BioPower in New Hampshire uses Tail-End SCR (following the particulate controls) and is described by the state:

> ***Burgess BioPower****: The biomass unit at this facility was subject to NNSR for NO_x at the time of their initial permitting; hence, the NO_x limit was established as the LAER[9] based limit. The NO_x limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NO_x/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups.*

The NPS recommends that a complete four-factor analysis of woodwaste boilers will include evaluation of SCR.

Burney Forest Products (Facility ID: 8411711)

NPS review finds that recent NO_x emissions from this facility result in Q/d = 4.7 at Lassen Volcanic National Park and that no further analysis is needed in this planning period.

Sierra Pacific Industries – Burney (Facility ID: 6575511)

NPS review finds that recent NO_x emissions from this facility result in Q/d = 3.9 at Lassen Volcanic National Park and that no further analysis is needed in this planning period.

Sierra Pacific Industries – Quincy (Facility ID: 3270411)

NPS review finds that recent NO_x emissions from this facility result in Q/d = 6.5 at Lassen Volcanic National Park. For this reason, the NPS recommends a four factor analysis for NO_x at Sierra Pacific Industries – Quincy.

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

Wheelabrator Shasta E.C.I. (Facility ID: 1673711)

NPS requests that CARB provide information on current emissions, fuel use for natural gas or bio-mass, and existing controls and control efficiencies for NO_x and SO_2 at this facility. These data are needed to support the SIP conclusion that no further controls are necessary. Because NO_x emissions result in Q/d = 8.9 at Lassen Volcanic National Park, the NPS recommends a four-factor analysis.

4.4 Other California facilities

Granite Construction – Lee Vining (Facility ID: 6649111)

Based on updated emissions information resulting in Q/d less than 5 for all NPS Class I areas, NPS concludes that no further analysis is needed for this facility.

Kirkwood Powerhouse (Facility ID: 13839511)

Based on updated emissions information resulting in Q/d less than 5 for all NPS Class I areas, the NPS agrees that no further analysis is needed for this facility.

Desert View Power (Facility ID: 15776111)

Operations at this facility on tribal land are permitted by U.S. EPA, not state or local agencies. No further analysis from CARB is needed for this facility.

Tamco (Facility ID: 4840211)

This was permanently shut down in January 2021 and no further analysis is needed.

Searles Valley Mineral (Facility ID: 4838811)

NPS requests that CARB provide information on what 2023 facility-wide NO_x and SO_2 projected emissions are based upon the requirements adopted in 2019. NPS review finds that 2017 NO_x emissions result in a Q/d value of 13.6 at Sequoia and Kings Canyon National Parks and recommends, four-factor analyses for NO_x. (SO_2 four factor analysis is unnecessary because Q/d < 5 at NPS Class I areas.)

California Steel Industries (Facility ID: 4839811)

NPS review finds that NO_x emissions appear to be well-controlled and result in Q/d = 1.3 at Joshua Tree National Park, no further analysis is needed for this facility.

New Indy Ontario LLC (Facility ID: 17240911)

NPS review finds that NO_x emissions appear to be well-controlled and result in Q/d = 1.4 at Joshua Tree National Park, no further analysis is needed for this facility.

5 Specific Review of Four-Factor Analysis

5.1 Collins Pine Company (Facility ID: 3270311)

5.1.1 Plant Characteristics

Collins owns and operates a wood products manufacturing and cogeneration facility located in Chester, California, 15 km southeast of Lassen Volcanic National Park, a Class I area administered by the National Park Service. Although 2017 emissions were relatively small—129 tons of NO_x and four tons of SO_2 —proximity to Lassen Volcanic National Park resulted in a NO_x Q/d value of 8.6, which exceeds the CARB selection threshold of Q/d > 5.

The existing lumber and sawmill operations debark whole logs and cut them to size with a variety of saws. The rough-cut material is either sold as-is or is further processed by planning and/or kiln drying. The facility produces and sells both green and dry lumber. Residual wood materials are generated onsite by various processes, including from debarking, sawing, and planning operations. The residuals are collected by a cyclone or one of the target boxes, and then stored for use in the facility's hogged fuel cogeneration boiler.

A portion of the rough-cut lumber is sent to the lumber dry kilns to remove excess moisture. The dried boards are then finished at the planer and sold as kiln dried lumber. All kilns are indirectly heated with steam produced by the Keeler cogeneration boiler. Steam energy produced by the Keeler cogeneration boiler is used to generate electricity to power the sawmill operations and no longer supplies energy to the electrical grid.

NPS review is based upon the September 16, 2021 report Prepared by Maul Foster & Alongi (MFA), Inc. on behalf of Collins Pine. In general, the MFA report was well done. NPS review finds some areas for improvement described below.

Keeler Cogeneration Boiler

As reported by MFA, the Keeler cogeneration boiler combusts clean lumber, clean hogged fuel, wood fuel, yard wastes or mixtures thereof to produce steam that is used for cogeneration (i.e., steam generates electricity and heat for processes). The boiler combusts an extremely limited amount of no. 2 diesel for start-up only. The Keeler boiler has a design heat input capacity when firing wood fuels (hogged wood, bark, chips) of 242.3 million British thermal units per hour, and can produce a maximum of 140,000 lb steam/hr. At the present time, the facility does not supply power to the electrical grid, and the 12 MW turbine is no longer in service as of December 2020.

The boiler uses multiclones followed by a dry electrostatic precipitator (DESP) to control particulate matter. Collins maintains and operates a continuous monitoring system to measure NO_x, carbon monoxide, and carbon dioxide concentrations from the boiler stack.

5.1.2 Selective non-catalytic reduction (SNCR)

SNCR systems have been widely employed to reduce NO_x emissions from biomass combustion systems. Application of SNCR to Collins Pine- Chester was evaluated by MFA through consultation with a subject matter expert. This expert recommended that: *although the temperature in the upper furnace is high enough for the reduction reaction using ammonia, the* *temperature is not adequate for application using urea reagent.* The expert also noted boiler configuration characteristics that are likely to increase ammonia slip in excess of the standard 20ppm limit. In conclusion the expert estimated that SNCR could achieve 20 to 25 percent control efficiency at a 25 ppm slip limit. MFA notes that no computational fluid dynamics modeling was conducted to determine that an SNCR would in fact work for this boiler. Without engineering analyses, the level of control efficiency cannot be guaranteed, and performance may be lower than the 20 to 25 percent range.

The Regional Haze Rule requires that the four statutory factors contained in the Clean Air Act be addressed.

Cost of Compliance (Statutory Factor 1)

MFA estimated that SNCR could reduce NO_x emissions by 32.3 tons/yr at an annual cost of $359,561 in 2019$. This results in a cost-effectiveness of $11,149/ton, which exceeds the values accepted by all of the other state SIPs reviewed by NPS so far in this regional haze planning period.[10] However, NPS review finds that the MFA analysis overestimated costs. NPS analysis updated the MFA analysis by:

- Using an updated SNCR Control Cost Manual (CCM) workbook. The obsolete workbook used by MFA was updated in 2021 because it tended to overestimate operating costs.
- Assuming use of ammonia instead of urea per the recommendation of MFA's consultant. The use of ammonia resulted in much lower reagent costs.
- Using the 2020 Chemical Engineering Plant Cost Index = 596.2 instead of 2019 = 607.5.
- Assuming no cost for make-up fuel because the boiler burns woodwaste produced at the plant.

Even though the Keeler cogeneration boiler is used to generate electricity to power the sawmill operations, NPS analysis included the electricity rate provided by MFA. NPS estimates that SNCR could reduce NO_x emissions by 32.8 tons/yr at an annual cost of $297,246 in 2020$; this results in a cost-effectiveness of $9,069/ton (see attached spreadsheets for calculations).

Time Necessary for Compliance (Statutory Factor 2)

It is anticipated that it will take up to 24 to 36 months to achieve complete installation and commissioning of a retrofit SNCR system.

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[10] For example, other states have set the following cost-effectiveness thresholds in their draft proposals:

$4,000 to $6,500/ton in Arizona

$5,000/ton in Arkansas (EGUs) and Texas

$5,000 to $10,000/ton in Nevada

$6,100/ton in Idaho

$6,250/ton for paper mills in WA

$10,000/ton in Colorado and Oregon

Energy and Non-air Environmental Impacts (Statutory Factor 3)

Energy and non-air environmental impacts cited by MFA are included in the Cost of Compliance and are not unique to Collins Pine—Chester.

CARB noted that operation of an SNCR system will also lead to increased water demands. Drought conditions persist in Plumas County where the facility is located. Exceptional drought conditions are present in the western portion of the county and extreme drought conditions are present in the eastern portion of the county.

SNCR typically consumes 14 gallons of water/hr. NPS recommends that CARB explain why this is a prohibitive water use given the benefits of air pollution control.

Remaining Useful Life of Source (Statutory Factor 4)

According to MFA it is anticipated that the remaining life of the emission unit, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. The emission unit is not subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the expectation is that the control system would be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emission unit.

5.1.3 Selective Catalytic Reduction and Hybrid Systems

MFA found that based on the likelihood of catalyst deactivation through particulate plugging and catalyst poisoning, and exhaust gas temperature well out of typical SCR operating range, SCR and SNCR/SCR hybrid systems are considered to be technically infeasible for control of NO_x emissions from wood-fired combustion units.

The NPS is aware of applications of SCR on woodwaste fired boilers, typically in a Tail-End configuration following the particulate control device. This may infact be feasible and is recommended for consideration. NPS analysis applied the CCM SCR workbook and estimated that SCR could reduce NO_x emissions by 111 tons/yr at an annual cost of $1,111,767 in 2020$; this results in a cost-effectiveness of $9,977/ton. However, it is likely that capital and operating costs will be higher due to the need to reheat the boiler exhaust to proper SCR operating temperature. Please see the attached spreadsheets for calculations.

Table 10. NPS estimates of cost-effectiveness for SNCR and SCR at Collins Pine-Chester.

Control Technology	**SNCR**	**SCR**	
Total Capital Investment	$ 3,285,500	$ 16,255,489	2020$
Capital Recovery Cost	$ 231,299	$ 986,708	/yr
Indirect Cost	$ 232,778	$ 990,261	/yr
Direct Cost	$ 64,469	$ 121,506	/yr
Total Annual Cost	$ 297,246	$ 1,111,767	/yr
Tons of NO_x Removed	32.775	111	ton/yr
Cost-Effectiveness	$ 9,069	$ 9,977	/ton

5.1.4 Conclusions and Recommendations

In Appendix A CARB finds that:

> *Additional emission control options for one stationary source were evaluated in detail. Staff concluded that no additional reasonable emission control options were currently feasible for this facility.*

NPS infers that this reference is to Collins Pine—Chester. NPS recommends that CARB explicitly provide rationale this conclusion.

The cost-effectiveness of SNCR at Collins Pine–Chester would be acceptable in Colorado, Oregon, and potentially other states. Depending upon the additional re-heat costs for SCR, this more effective technology may also be cost-effective.

Considering that other woodwaste-fired boilers in California are currently using SNCR to reduce NO_x, adding SNCR at Collins Pine—Chester would improve consistency among similar emission sources and while reducing haze causing NO_x emissions 15km from the border of Lassen Volcanic National Park. The NPS recommends that CARB require all technically feasible cost-effective controls identified through four factor analysis in order to address regional haze.

File Code: 2580
Date 4/8/2022

Ms. Alicia Adams
Manager, Air Quality Planning and Science Division
California Air Resources Board

Dear *Ms. Adams*:

On February 9, 2022, the State of California submitted a draft Regional Haze State Implementation Plan describing your proposal to continue improving air quality by reducing regional haze impacts at mandatory Class I areas across the region. We appreciate the opportunity to work closely with the California Air Resources Board (CARB) through the initial evaluation, development, and subsequent review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I areas.

This letter acknowledges that the U.S. Department of Agriculture, U.S. Forest Service (USFS), has received and conducted a substantive review of your proposed Regional Haze State Implementation Plan. This review satisfies your requirements under the federal regulations 40 C.F.R. § 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness, and therefore, only the EPA has the authority to approve the document.

Fire has played an important role in the fire prone and adapted areas of California and created the environmental systems that help provide the state with clean water and air and provide the unique ecosystems that bring people across the globe to visit and enjoy. Smoke associated with large mega-fires is wider spread and more dense than prescribed and managed wildfires for multiple objectives and often reaches large urban areas. As small fires prevent future big fires, so do small smoke events prevent future, larger events. Area burned under favorable conditions helps prevent the larger, unwanted fire and the subsequent extreme smoke event. There is far less smoke with smaller managed burns than large uncontrolled mega-fires. To the greatest extent possible, restoring fire on the landscape correctly should be encouraged for the best air quality outcomes. The USFS appreciates CARBs efforts and are largely satisfied with the document and only offer a few suggestions.

The 2017 Regional Haze Rule includes a provision to allow states to adjust the glidepath to account for international and wildland prescribed fire emissions. The draft SIP indicates California will utilize the adjustment for both international and prescribed fire. The USFS applauds California's decision to adjust the 2064 glidepath to account for prescribed fire impacts on visibility. This proposed adjustment was made using data published in Product 5 of the WRAP TSS taken from the 2014v2 National Emissions Inventory (NEI). However, the USFS respectfully request to consider the WRAP TSS Product 18 "Future Fire Scenario 2" modeling results, as noted in Appendix F to this SIP, as these are likely more accurately reflect the future wildland prescribed acres treated as well as likely effects on visibility.

The USFS would prefer the inclusion of oxides of sulfur (SOx) emissions to better assess potential control strategies or at a minimum include a more detailed discussion on the reasoning used to determine the exclusion of SOx emissions. While we agree oxides of nitrogen (NOx) emissions are extremely important and warrant an extensive analysis, anthropogenic SOx emissions remain a potential source of precursors of ammonium sulfate impacting Class I Wilderness in California at numerous sites managed by the USFS. The USFS advises that the IMPROVE site SEQU1 in Figure ES-3 is not representative of many other Class I Wilderness in the state because the site is downwind and nearer to large agricultural land use areas in the Central Valley where NOx emission contribution to haze are much more significant than other IMPROVE sites. For example, SOx emissions may have a larger relative contribution in many areas including Class I Wilderness in the southern part of the state (Figure 4-3). Also, given that SOx emissions to some extent increases haze at all locations, the USFS suggest that any further reductions will only further improve visibility in Class I Wilderness and have the additional benefit of reducing air pollution nearer the point sources and thus inclusion could be warranted. Additionally, the USFS would suggest inclusion of SOx emissions and further light extinction analysis at IMPROVE sites would inform potential changes in emissions sources (e.g. increased ship wait times and emissions at the Port of Los Angeles) that otherwise may be overlooked.

Again, we appreciate the opportunity to work closely with the State of California. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

Jennifer Eberlien
Regional Forester
Region 5

Cc: *********

J. Regional Haze Plan Crosswalk

Table J-1: Regional Haze Program Requirements for Periodic Comprehensive Revisions of Implementation Plans

Citation	Requirement	Location in Plan
40 CFR 51.308(f)(1)	Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress	Chapters 2 and 8; Appendix C
40 CFR 51.308(f)(1)(i)	Baseline visibility conditions for the most impaired and clearest days	Tables 2-3, 2-6, 2-9
40 CFR 51.308(f)(1)(ii)	Natural visibility conditions for the most impaired and clearest days	Tables 2-4, 2-5, 2-7, 2-8, 2-10, 2-11
40 CFR 51.308(f)(1)(iii)	Current visibility conditions for the most impaired and clearest days	Tables 2-3, 2-6, 2-9
40 CFR 51.308(f)(1)(iv)	Progress to date for the most impaired and clearest days	Tables 2-4, 2-5, 2-7, 2-8, 2-10, 2-11
40 CFR 51.308(f)(1)(v)	Differences between current visibility condition and natural visibility condition for the most impaired and clearest days	Tables 2-4, 2-5, 2-7, 2-8, 2-10, 2-11
40 CFR 51.308(f)(1)(vi)(A)	Uniform rate of progress to attain natural visibility conditions by the end of 2064	Tables 8-3, 8-4, 8-5
40 CFR 51.308(f)(1)(vi)(B)	Proposed adjustments to the uniform rate of progress to account for impacts from wildland prescribed fires and anthropogenic sources outside of the U.S.	Tables 8-2, 8-3, 8-4, 8-5
40 CFR 51.308(f)(2)	Long-term strategy for regional haze	Chapter 7
40 CFR 51.308(f)(2)(i)	Evaluation of emission reductions measures that are necessary to make reasonable progress as determined by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of potentially affected anthropogenic sources. Description of criteria used to determine which sources to evaluate and how the four factors were taken into consideration in selecting the measures for inclusion in the long-term strategy.	Chapter 6; Appendix H Chapter 5
40 CFR 51.308(f)(2)(ii)	Interstate consultation to support development of coordinated emission management strategies	Chapter 9
40 CFR 51.308(f)(2)(ii)(A)	Demonstrate inclusion of all measures agreed to during interstate consultation	Not applicable
40 CFR 51.308(f)(2)(ii)(B)	Consideration of emission reduction measures identified by other states as being necessary to make reasonable progress	Not applicable
40 CFR 51.308(f)(2)(ii)(C)	Description of actions taken in situations in which states cannot agree on the emission reduction measures necessary to make reasonable progress	Not applicable
40 CFR 51.308(f)(2)(iii)	Technical basis, including modeling, monitoring, cost, engineering, and emissions information, used to determine the emission reduction	Chapter 7 and references therein

Citation	Requirement	Location in Plan
	measures necessary to make reasonable progress in each mandatory Class I Federal area affected by the state's emissions	
40 CFR 51.308(f)(2)(iv)(A)	Consideration of emission reductions due to ongoing air pollution control programs in developing the long-term strategy	Chapter 7
40 CFR 51.308(f)(2)(iv)(B)	Consideration of measures to mitigate the impacts of construction activities in developing the long-term strategy	Chapter 7
40 CFR 51.308(f)(2)(iv)(C)	Consideration of source retirement and replacement schedules in developing the long-term strategy	Chapter 7
40 CFR 51.308(f)(2)(iv)(D)	Consideration of basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs in developing the long-term strategy	Chapter 7
40 CFR 51.308(f)(2)(iv)(E)	Consideration of the anticipated net effect on visibility due to projected changes in emissions over the period addressed by the long-term strategy	Chapter 7
40 CFR 51.308(f)(3)(i)	Reasonable progress goals for the most impaired and clearest days	Table 8-1
40 CFR 51.308(f)(3)(ii)(A)	Additional requirements that apply if reasonable progress goals for the most impaired days provide for a slower rate of improvement than the uniform rate of progress	Not applicable
40 CFR 51.308(f)(3)(ii)(B)	If a state contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another state, demonstrate that there are no additional emission reduction measures that would be reasonable to include in the long-term strategy	Not applicable
40 CFR 51.308(f)(4)	Requirements if Administrator, Regional Administrator, or Federal Land Manager has advised state of a need for additional monitoring	Not applicable
40 CFR 51.308(f)(5)	Direction to address requirements of paragraphs (g)(1) through (5) so that the plan revision will also serve as a progress report	Chapter 10
40 CFR 51.308(f)(6)	Monitoring strategy	Chapter 2
40 CFR 51.308(f)(6)(i)	Establishment of additional monitoring sites or equipment needed to assess whether reasonable progress goals are being achieved	Not applicable
40 CFR 51.308(f)(6)(ii)	Procedures by which monitoring data and other information are used in determining the contribution of emissions from within the state to regional haze visibility impairment at mandatory Class I Federal areas within and outside of the state	Chapter 4
40 CFR 51.308(f)(6)(iii)	Requirements for states with no mandatory Class I Federal areas	Not applicable
40 CFR 51.308(f)(6)(iv)	Provide for the reporting of all visibility monitoring data to the Administrator at least annually for each mandatory Class I Federal area in the state	Chapter 2
40 CFR 51.308(f)(6)(v)	Statewide inventory of emissions that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area.	Chapter 3; Appendix E

Citation	Requirement	Location in Plan
	Commitment to update the inventory periodically.	
40 CFR 51.308(f)(6)(vi)	Provide information on any other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility.	Throughout
40 CFR 51.308(g)(1)	Describe the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the state.	Chapter 10
40 CFR 51.308(g)(2)	Summarize the emissions reductions achieved throughout the state through implementation of the measures including in the implementation plan.	Chapter 10
40 CFR 51.308(g)(3)(i)(A)	Current visibility conditions for the most impaired and least impaired days	Chapter 10
40 CFR 51.308(g)(3)(i)(B)	Current visibility conditions for the most impaired and clearest days	Not applicable for this progress report
40 CFR 51.308(g)(3)(ii)(A)	Difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions	Chapter 10
40 CFR 51.308(g)(3)(ii)(B)	Difference between current visibility conditions for the most impaired and clearest days and baseline visibility conditions	Not applicable for this progress report
40 CFR 51.308(g)(3)(iii)(A)	Change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most plan required under paragraph (f) of this section	Chapter 10
40 CFR 51.308(g)(3)(iii)(B)	Change in visibility impairment for the most impaired and clearest days over the period since the period addressed in the most plan required under paragraph (f) of this section	Not applicable for this progress report
40 CFR 51.308(g)(4)	Provide analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the state. Emissions changes should be identified by the type of source or activity.	Chapter 10
40 CFR 51.308(g)(5)	Assessment of any significant changes in anthropogenic emissions within or outside the state that have occurred since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.	Chapter 10
40 CFR 51.308(g)(6)	Assess whether the current implementation plan elements and strategies are sufficient to enable the state, or other states with mandatory Class I Federal areas affected by emissions from the state, to meet all established reasonable progress goals for the period covered by the most recent plan required under paragraph (f) of this section.	Chapter 7
40 CFR 51.308(g)(7)	For progress reports for the first implementation period only, a review of the state's visibility monitoring strategy and any modifications to the strategy as necessary.	Not applicable
40 CFR 51.308(g)(8)	For a state with a long-term strategy that includes a smoke management program for prescribed fires on wildland that conducts a periodic program assessment, a summary of the most recent	Not applicable

Citation	Requirement	Location in Plan
	periodic assessment of the smoke management program including conclusions if any that were reached in the assessment as to whether the program is meeting its goals regarding improving ecosystem health and reducing the damaging effects of catastrophic wildfires.	
40 CFR 51.308(h)(1)	Following determination that existing implementation does not require a substantive revision, declaration that revision of existing implementation plan is not needed at this time.	Not applicable for this progress report
40 CFR 51.308(i)(2)	Consultation with Federal Land Managers	Chapter 9
40 CFR 51.308(i)(3)	Address comments provided by Federal Land Managers	Appendix I
40 CFR 51.308(i)(4)	Procedures for continuing consultation with Federal Land Managers	Chapter 9