Utah State Implementation Plan

Regional Haze Second Implementation Period

Section XX.A

[August 1, 2022]

List of tables

List of figures

List of acronyms

BACT	Best Available Control Technology
BACM	Best Available Control Measures
CIA	Class 1 Area
CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model with Extensions
CCR	Consumer Confidence Report
CF	Code of Federal Regulations
CIRA	Cooperative Institute for Research in the Atmosphere
CO	Carbon Monoxide
CSU	Colorado State University
DAQ	Division of Air Quality
DEQ	Department of Environmental Quality
EPA	Environmental Protection Agency
FLM	Federal Land Manager
FWS	US Fish and Wildlife Service
GCVTC	Grand Canyon Visibility Transportation Commission
IMPROVE	Interagency Monitoring of Protected Visibility Elements
LTS	Long Term Strategy
NAAQS	National Ambient Air Quality Standards
NOI	Notice of Intent
NO2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NPS	National Parks Service
O3	Ozone
PAL	Plantwide Applicability Limit
PB	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than 10 Microns in Diameter
$PM_{2.5}$	Particulate Matter Smaller Than 2.5 Microns in Diameter
RH	Regional Haze
RHR	Regional Haze Rule
RHPWG	Regional Haze Planning Work Group (WRAP)
RPEL	Reasonable Progress Emissions Limit
RPG	Reasonable Progress Goals
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SO_x	Sulfur Oxides
TSS	Technical Support System
UDOGM	Utah Division of Oil, Gas, and Mining
URP	Uniform Rate of Progress
UAC	Utah Administrative Code
USFS	US Forest Service
VOCs	Volatile Organic Compounds
WESTAR	Western States Air Resources

WRAP	Western Regional Air Partnership

EXECUTIVE SUMMARY

This document comprises the State of Utah's State Implementation Plan (SIP) submittal to the U.S. Environmental Protection Agency (EPA) under the Regional Haze Rule.[1] The purpose of this SIP revision is to comply with the requirements of the Regional Haze Rule (RHR).[2] Specifically, this SIP addresses requirements for periodic comprehensive revisions of implementation plans for regional haze.[3] The RHR requires Utah to address regional haze in each mandatory Class I Area (CIA) located within Utah and in each mandatory CIA located outside Utah that may be affected by primary pollutants emitted from sources within Utah. Utah is required to submit a SIP addressing the specific elements required by the rule.

The objectives of the RHR are to improve existing visibility in 156 national parks, wilderness areas, and monuments (termed Mandatory Class I Areas or CIAs), prevent future impairment of visibility by manmade sources, and meet the national goal of natural visibility conditions in all mandatory CIAs by 2064. Utah's CIAs consist of: Arches National Park, Bryce Canyon National Park, Canyonlands National Park, Capitol Reef National Park, and Zion National Park.[4]

The RHR establishes several planning periods extending from 2005 to 2064. The State of Utah is required to develop a Regional Haze (RH) SIP for each period. The first implementation period spanned from 2008 to 2018. This SIP revision consists of the second implementation period spanning from 2018 to 2028. This SIP was originally due for submittal to the EPA on July 31st, 2018. However, the deadline was extended to July 31st, 2021. In this revision, UDAQ demonstrates the visibility progress to date[5] in each of Utah's CIAs and analyzes Utah's emissions trends and sources of visibility impairment[6]. Utah is required to set reasonable progress goals which 1) must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and 2) ensure no degradation in visibility for the least impaired days over the same period.[7] For this purpose, Utah has outlined its Long-Term Strategy (LTS) in this document[8] as well as determination of reasonable progress goals (RPGs) for CIAs in Utah.

The RH SIP must also address mandatory CIAs outside of the state that are reasonably anticipated to be affected by emissions from Utah as well as out-of-state sources impacting Utah CIAs. For this requirement, UDAQ analyzed Western Regional Air Partnership (WRAP) photochemical modeling and found that Utah does not significantly impact visibility at out-of-

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[1] 40 CFR 51.308(f) and (g)

[2] 40 CFR 51
[3] 40 CFR 51.308(f)
[4] See chapter 1 for more information on the RHR and Utah's regional haze history
[5] See chapter 3 to view Utah's visibility and emissions reduction progress to date
[6] See chapter 5 to review Utah's sources of visibility impairment
[7] See chapter 8 for more information on Utah's reasonable progress goals
[8] See chapter 6 for Utah's Long-Term Strategy

state CIAs.[9] Utah has also determined that Utah's CIAs are not significantly impacted by out-of-state sources. Upon consultation with Utah's surrounding states, Utah will not require any actions from other states for impacts on Utah's CIAs and Utah has received no requests for actions regarding Utah sources' impacts on out-of-state CIAs.[10]

Throughout this second implementation period, UDAQ has participated in the WRAP, which has conducted modeling and technical analysis for the purposes of supporting state RH planning. UDAQ has also consulted with Federal Land Managers (FLMs), Tribes, Utah's surrounding states, as well as environmental advocates, industry stakeholders, and the public.[11]

This SIP revision also determines what control measures are necessary for reasonable progress in the second implementation period. The examination required to determine new control measures for this period is known as a four-factor analysis[12] and consists of four criteria: 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts, and 4) remaining useful life. In order to determine which sources must submit a four-factor analysis to the State, UDAQ performed a Q/d (emissions/distance) analysis to determine which of Utah's sources have the highest potential visibility impact on Utah's CIAs. These facilities include the Ash Grove Cement Company Leamington Cement Plant, the Graymont Western US Inc. Cricket Mountain Plant, the PacifiCorp Hunter and Huntington Plants, the Sunnyside Cogeneration Associated Sunnyside Cogeneration Facility, and the US Magnesium LLC Rowley Plant. UDAQ requested each facility to submit a four-factor analysis for the purpose of this second implementation period. UDAQ has received each facility's four-factor analysis, provided each with an evaluation of their analysis, received evaluation responses from each, and subsequent information submittals[13]. After consideration of the information provided, as well as the modeling results provided by the WRAP, UDAQ has made the following reasonable progress determinations[14] for Utah's second implementation period of regional haze planning.

UDAQ identified several existing measures necessary for reasonable progress, including federal on-road and non-road vehicle and equipment standards, BACM measures and BACT controls included in the recently completed Serious Area PM2.5 SIP for the Salt Lake Nonattainment Area, as well as the following first implementation period regional haze controls:

- Existing NO_x control rate-based limits and Hunter power plant
- Existing NO_x control rate-based limits and Huntington power plant

[9] See sections 6.A.1 and 6.A.2 for Utah's impacts on out of state CIAs and other state's impacts on Utah's CIAs
[10] See Appendix B for interstate consultation agreement documentation
[11] See chapter 9 for details on Utah's consultation efforts
[12] See chapter 7 for Utah's source selection and the four-factor analyses, evaluations, responses, and conclusions for each source
[13] See Appendix D.2 to view additional information submittals by sources
[14] See sections 6.A.10 to view Utah's Long-Term Strategy, 8.D to view UDAQ's reasonable progress determinations, and IX.H in appendix A to view the enforceable language for these determinations.

- Existing SO_2 limits for Hunter power plant (Section 309 control added to SIP in round 2)
- Existing SO_2 limits for Huntington power plant (Section 309 control added to SIP in round 2)
- Closure of the Carbon power plant

UDAQ also identified and included the following existing control measures to ensure ongoing enforceability in the second implementation period:

- Ash Grove
- Graymont
- Sunnyside
- US Magnesium
- Intermountain Generation Station

Finally, UDAQ identified and included the following new control measures as necessary for reasonable progress:

- A plantwide enforceable mass-based NO_x limit on Hunter power plant
- A plantwide enforceable mass-based NO_x limit on Huntington power plant
- Installation of FGR on the US Magnesium Rowley Plant Riley Boiler
- An enforceable closure date for Units 1 and 2 of the Intermountain Generation Station

Chapter 1: Background and Overview of the Federal Regional Haze Rule

1.A Regional Haze Planning Periods and Due Dates

Utah took part in early regional haze planning through participation in the Grand Canyon Visibility Transport Commission (GCVTC), which originally consisted of nine states and 211 tribal lands. In 1996, the GCVTC submitted a report containing recommendations for improving western vistas.[15] In 2000, Utah established Sulfur Dioxide (SO_2) milestones with an Annex[16] to the original GCVTC report through the Western Regional Air Partnership. Based on the recommendations of the GCVTC and the Annex, in 2003 Utah's Air Quality Board adopted section XX[17] of the State Implementation Plan (SIP) to address regional haze and the many source categories and pollutants contributing to the regional haze in Utah. The first state plans were due in 2007 and the last date for states to submit initial regional haze control plans for all Mandatory Federal CIAs was in 2008. Utah submitted its evaluation of the Best Available Retrofit Technology (BART) in 2015[18] along with a revision in 2019[19]. Progress reports are due every five years and full plan revisions are required every 10 years. The first revision was originally due in 2018, but in 2017 EPA extended the deadline to July 31, 2021 with the latest revision of the Regional Haze Rule (RHR)[20]. As part of the RH SIP process, Utah must work towards the overarching goal of achieving natural visibility in its CIAs by 2064. This timeline is summarized in the figure below.

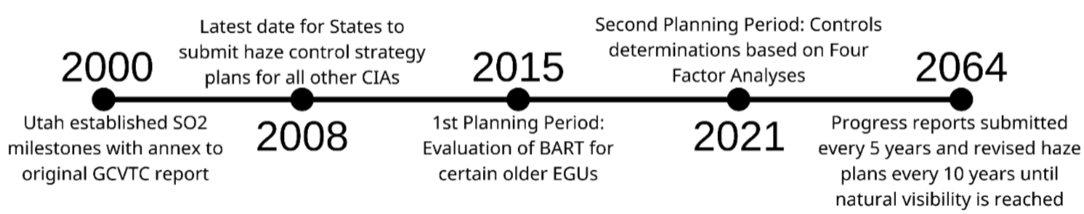

Figure 1: Regional Haze Timeline option for GCVTC areas

[15] The original 1996 report of The Grand Canyon Visibility Transport Commission can be found at https://www.phoenixvis.net/PDF/GCVTCFinal.pdf
[16] The EPA Notice of Availability of the Annex to the Report of The Grand Canyon Visibility Transport Commission can be found at https://www.federalregister.gov/documents/2000/11/15/00-29226/notice-of-availability-of-annex-to-the-report-of-the-grand-canyon-visibility-transport-commission
[17] Section XX of Utah's Regional Haze SIP can be found at https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008934.pdf
[18] Utah's 2015 RH SIP can be found at https://documents.deq.utah.gov/legacy/laws-and-rules/air-quality/sip/docs/2015/07Jul/SecXXRegHaze201Final.pdf
[19] Utah's 2019 RH SIP revision can be found at https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2019-012208.pdf
[20] 40 C.F.R. § 51.308(f). For the purposes of this SIP submittal, the RHR acronym refers to the most current 2017 Regional Haze Rule revisions.

1.B Class I Areas in Utah

In the 1977 Clean Air Act, Congress established requirements for the prevention of significant deterioration of air quality in areas within the United States and for the review of pollution controls on new sources. Coupled with this, Congress established a visibility protection program for those larger national parks and wilderness areas designated as mandatory Federal CIAs. This program establishes a national goal of "the prevention of any future, and remedying of any existing, impairment of visibility in mandatory CIAs which impairment results from manmade air pollution"[21] and requires states to develop long-term strategies to assure reasonable progress toward this national goal. 40 CFR 81.400 Scope: Subpart D, §§ 81.401 through 81.437, lists Mandatory Federal CIAs, where the Administrator, in consultation with the Secretary of the Interior, has determined visibility to be an important value.

As shown in Figure 2, there are five Mandatory Federal CIAs in Utah, all of which are National Parks: Arches National Park, Bryce National Park, Canyonlands National Park, Capitol Reef National Park and Zion National Park. The following sections include data from the National Parks Service (NPS) Stats website.[22]

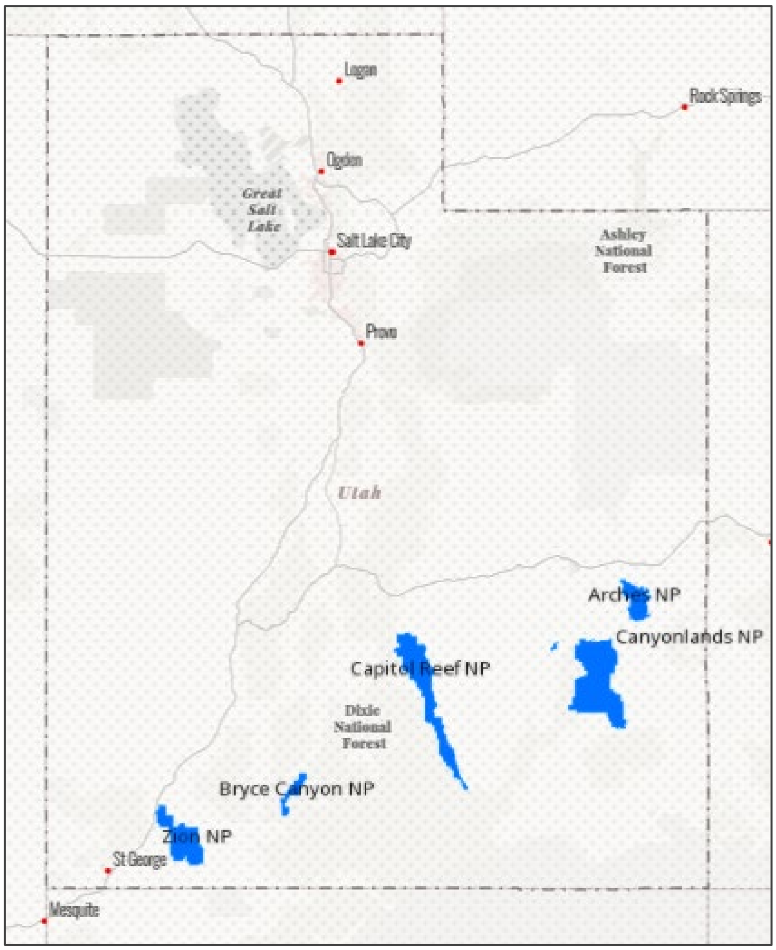

Figure 2: Map of Utah CIAs

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[21] 42 U.S.C.A. § 7491(a)(1) (West).
[22] Statistics for all the National Parks discussed in this section come from the NPS Stats website at: https://irma.nps.gov/STATS/

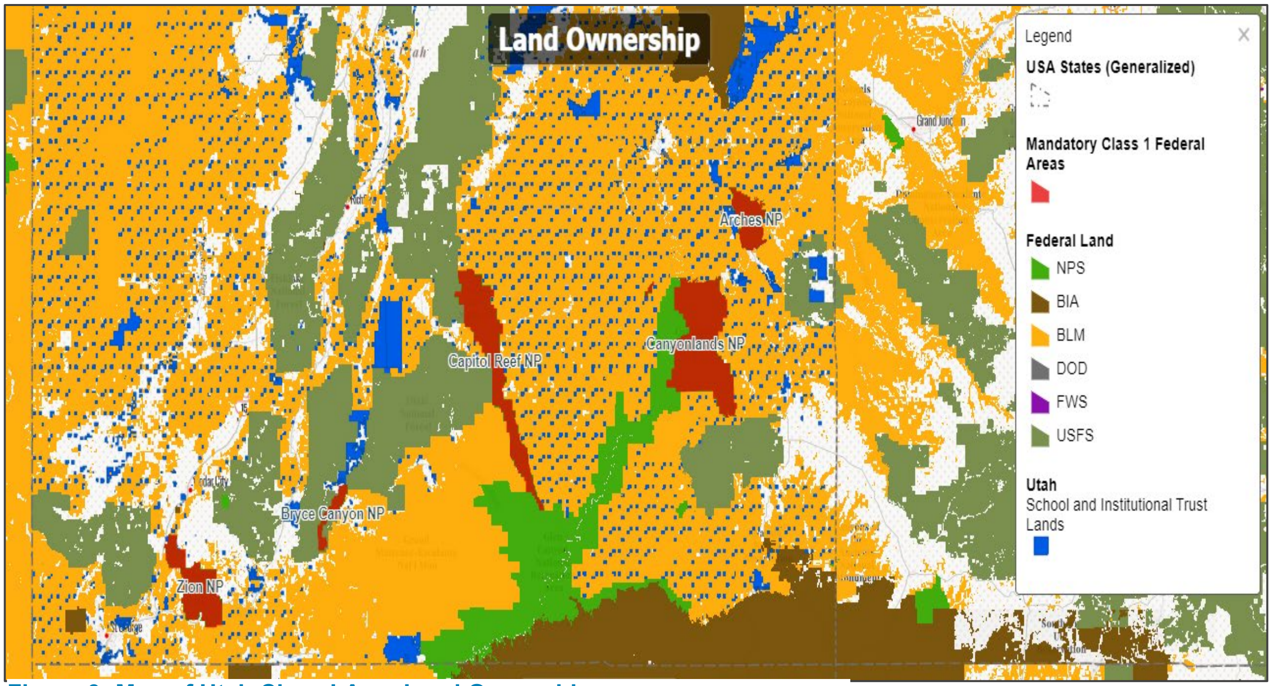

Figure 3: Map of Utah Class I Area Land Ownership

1.B.1 Arches National Park


Figure 4: Arches National Park

Arches National Park was originally designated as a National Monument in 1929 and became a national park in 1978. Congress established the park "to protect extraordinary examples of geologic features including arches, natural bridges, windows, spires, balanced rocks, as well as other features of geologic, historic, and scientific interest, and to provide opportunities to experience these resources and their associated values in their majestic natural settings."[23] Located in southwest Utah, Arches National Park is home to over 2,000 cataloged, naturally formed, sandstone arches. These 76,679 acres of red sandstone are surrounded by thousands of acres of additional natural lands, administered mainly by the Bureau of Land Management and Utah's School and Institutional Trust Lands Administration (See Figure 3). Over 1.6 million people visited Arches in 2019.[24] Over the past 10 years, park visitation has increased, on average, five percent each year.[25] The largest population center near Arches National Park is Moab. This town of over 5,300 residents[26] is about five miles south of the Park. It is the major hub for recreation in Arches, Canyonlands National Park, and the surrounding areas.

1.B.2 Bryce Canyon National Park

Bryce Canyon was originally established as a National Monument in June 1923. One year later it was designated a national park. According to its foundation document, the purpose of the park was to "protect and conserve resources integral to a landscape of unusual scenic beauty exemplified by highly colored and fantastically eroded geological features, including rock fins and spires, for the benefit and enjoyment of the people."[27] Bryce Canyon contains the highest concentration of irregular rock columns (Hoodoos) on Earth. Located in southern Utah near the city of Bryce, the national park sits along the edge of a high plateau on top of the Grand Staircase. At 35,835 acres, Bryce Canyon is Utah's smallest National Park. However, nearly 2.6 million people visited Bryce Canyon in 2019.[28]

Figure 5: Bryce Canyon National Park

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[23] Arches National Park Foundation Document, website: https://www.nps.gov/arch/learn/management/foundation-document.htm#CP_JUMP_5740028
[24] Data source: Stats Report Viewer (nps.gov).
[25] *See id*.
[26] United States Census Bureau, website: https://www.census.gov/quickfacts/moabcityutah (data for July 1, 2019).
[27] Bryce Canyon National Park Foundation Document, website: https://www.nps.gov/brca/learn/management/upload/BRCA_FD_SP.pdf
[28] Data source: Stats Report Viewer (nps.gov).

1.B.3 Canyonlands National Park

Canyonlands National Park was originally established on September 12, 1964 with the help of Bates Wilson, the superintendent of Arches National Park. Located near Moab, Utah with 337,598 acres of land and water, Canyonlands is Utah's largest national park. The Green and Colorado rivers split this section of the Colorado Plateau into three main districts: "Island in the Sky," "The Needles," and "The Maze." Since 2007, over 400,000 people visit Canyonlands each year with a record of 776,218 in 2016 alone.[29] Canyonlands features deep canyons, mesas, pinnacles, cliffs, and spires and contains one of the most photographed landforms in the west—the Mesa Arch.

Figure 6: Canyonlands National Park

1.B.4 Capitol Reef National Park

Figure 7: Capitol Reef National Park

Capitol Reef National Park was originally designated a national monument in August 1937 but then turned into a national park in 1971. Spanning 241,904 acres, Capitol Reef is made of a geologic monocline almost 100 miles long. This monocline is called the Waterpocket Fold and is considered a geologic warp in the

[29] Data source: Stats Report Viewer (nps.gov).

Earth's crust spanning from Thousand Lake Mountain to Lake Powell. The tall, seemingly impassible ridges made by the Waterpocket Fold were called "reefs" by early settlers. The white Navajo sandstone dome formations appear like those placed on capitol buildings, giving the park its name. Capitol Reef had 1,226,519 visitors in 2019[30] and offers many hiking and backpacking opportunities, including 71 campsites.

1.B.5 Zion National Park

Figure 8: Zion National Park

Established on July 31, 1909, Zion National Park was the first national park in Utah. It is also the fourth most visited National Park in the United States with 4.48 million visitors in 2019.[31] The park's 147,243 acres contain the Zion Canyon which is 15 miles long and 2,640 feet tall.[32] The purpose of Zion National Park is to "preserve the dramatic geology including Zion Canyon and a labyrinth of deep and brilliantly colored Navajo sandstone canyons formed by extraordinary processes of erosion at the margin of the Colorado Plateau."[33] Located in southwestern Utah near St. George, Zion is home to famous hikes including Angel's Landing, The narrows, Observation Point, and the Emerald Pools.

1.C Haze Characteristics and Effects

Unimpaired visibility is important to fully enjoy the experience of visiting Utah's national parks and wilderness areas. Visibility is defined as the greatest distance at which an observer can see a black object viewed against the horizon sky. Visibility is impaired by light scattering and absorption caused by PM and gases in the atmosphere that occur from both natural and anthropogenic activities. This diminished clarity is called haze. Haze obscures the color, texture, and form of objects that can be seen at a distance.

Visibility can be impaired by natural sources such as rain, wildland fires, volcanic activity, sea mists, and wind-blown dust from undisturbed desert areas. Visibility also can be impaired by anthropogenic sources of air pollution such as industrial processes, (utilities, smelters,

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[30] Data source: Stats Report Viewer (nps.gov).
[31] Data source: Stats Report Viewer (nps.gov).
[32] Data Source: https://www.nps.gov/subjects/lwcf/upload/NPS-Acreage-12-31-2012.pdf

[33] Zion National Park Foundation Document, website: https://www.nps.gov/zion/learn/management/upload/ZION_Foundation_Document_SP-2.pdf

refineries, etc.), mobile sources (cars, trucks, trains, etc.), and area sources (residential wood burning, prescribed burning on wild and agricultural lands, wind-blown dust from disturbed soils, etc.). These sources emit pollutants that, in higher concentrations, can also affect public health.

Regional haze is the cumulative impact of emissions from varied sources, often located over a broad geographic area. The haze-causing particles can be transported great distances in the air, sometimes hundreds or thousands of miles. Therefore, one single source of emissions may not have a visible impact on haze, but emissions from many sources in a region can add up and cause haziness.

There are different metrics to measure impact on visibility. Visual range is the most intuitive and is defined as the distance at which a given standard object can be seen with the unaided eye. It is measured in miles or kilometers. A deciview is a unit of visibility proportional to the logarithm of the atmospheric light extinction. This unit will be used in many figures and tables within this report. Deciviews measure visibility derived from light extinction so that incremental changes in the haze index correspond to uniform incremental changes in visual perception ranging from pristine to highly impaired conditions.

1.D Monitoring Strategy[34]

Figure 9: Monitoring station for Capitol Reef National Park

Interagency Monitoring of Protected Visual Environments (IMPROVE) was designated as the visibility monitoring network representative of the 156 visibility-protected federal CIAs. IMPROVE was developed in 1985 to establish current visibility conditions, track changes in visibility, and help determine the causes and sources of visibility impairment in CIAs. The network is comprised of 110 monitoring sites across the nation[35], four of which are in Utah. IMPROVE monitoring sites in Utah's CIAs include those at Canyonlands National Park (monitoring site for both Arches and Canyonlands national parks), Capitol Reef National Park, Bryce Canyon National Park, and Zion National Park. Figure 10 through Figure 12 show three of Utah's monitoring stations.

[34] 40 CFR 51.308(f)(6) (IMPROVE PROGRAM)
[35] Shown in Figure 13

The IMPROVE monitoring sites contain equipment programmed to automatically collect samples of haze-forming particles from the air continually. Local operators at each field site—in many cases a park ranger, firefighter, or rancher—inspect the samples and exchange filters weekly, shipping all exposed filters back to the Air Quality Research Center (AQRC) at the University of California (UC) Davis every three weeks. Each month, the program's 110 field sites generate about 7,000 filters, which are processed in AQRC's laboratories by staff members and UC Davis students working part-time.[36] The analyses conducted at the AQRC test samples for various pollutants and trace metals and estimate the light scattering effect of each species This estimation results in a light extinction value. For purposes of the RHR, light extinction is estimated for sulfate, nitrate, organic mass by carbon (OMC), light absorbing carbon (LAC), fine soil (FS), sea salt, and coarse material (CM)—all components of particulate emissions. Figure 12 shows the four separate modules used for sampling the different species.

Figure 11: Monitoring station for Bryce Canyon National Park

Figure 10: Monitoring station for Canyonlands and Arches National Park

[36] For more information see: https://aqrc.ucdavis.edu/improve

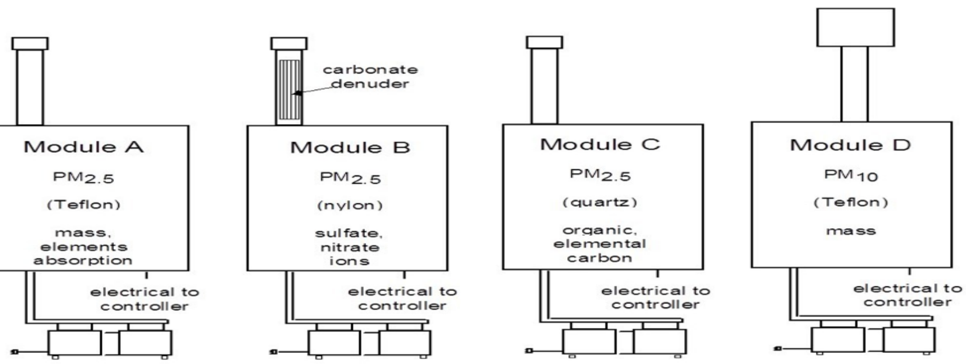

Figure 12: Monitoring station layout

1.D.1 Participation in the IMPROVE Network

In 1985, the IMPROVE program was established to coordinate the monitoring of air quality in national parks and wilderness areas and to ensure sound and consistent scientific methods were being used. The IMPROVE Steering Committee established monitoring protocols for visibility measurement, PM measurement, and scientific photography of the CIAs. IMPROVE monitoring is designed to establish reference information on visibility conditions and trends to aid in the development of visibility protection programs. Monitoring from the IMPROVE network, shown in Figure 13, demonstrated that visibility in all the CIAs is impaired to some degree by regional haze.

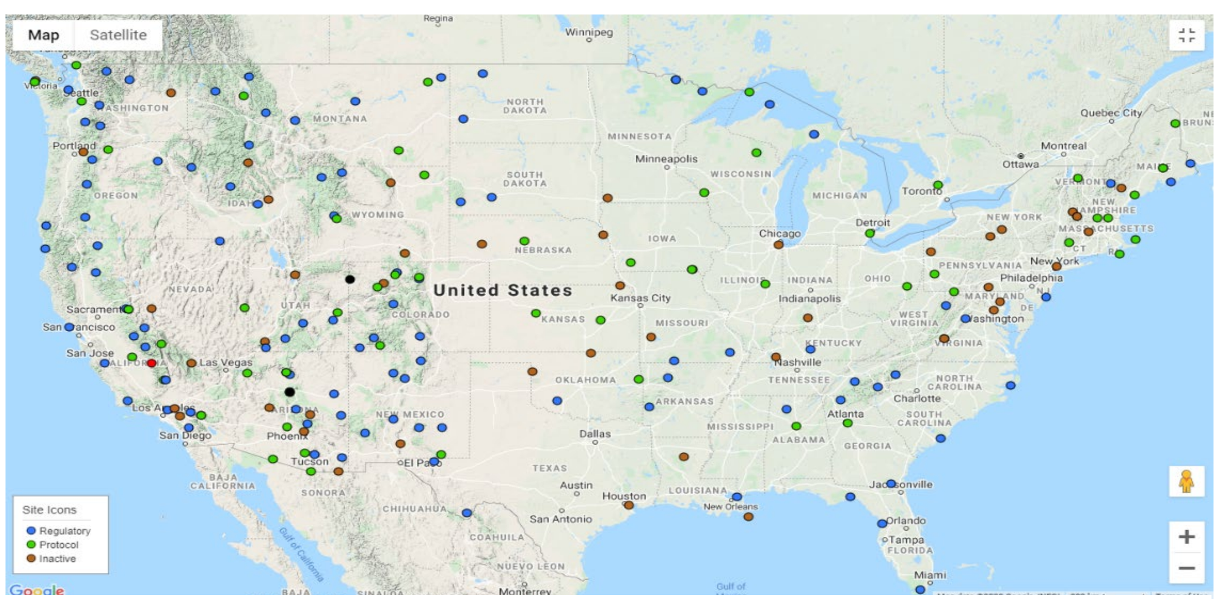

Figure 13: IMPROVE monitoring sites

1.E History of Regional Haze in Utah

Utah has been at the forefront of haze improvement and prevention since 1991 when the GCVTC was formed. The GCVTC recognized haze as a regional issue prior to the creation of the RHR in 1999 and was the first multi-state collaborative effort to address visual air quality issues. In recognition of the GCVTC, Section 309 of the RHR provided an early regional haze planning opportunity for states within the Colorado Plateau region. Utah is one of the five states to submit a complete Section 309 regional haze plan in 2003.

In amendments to the Clean Air Act (CAA) in 1977, Congress added Section 169A setting the national visibility goal of restoring pristine conditions in national parks and wilderness areas: "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory CIAs which impairment results from man-made air pollution."[37]

When the CAA was amended in 1990, Congress added Section 169B,[38] authorizing further research and regular assessments of the progress to improve visibility in the mandatory CIAs.[39]

[37] 42 U.S.C.A. § 7491.
[38] *See id*. § 7492.
[39] Figure 14: Map of 156 Mandatory Federal CIAs shows the location of the CIAs of concern and the Federal Land Managers (FLMs) responsible for each area around the nation.

The RHR specifies that these CIAs should attain “natural conditions” by 2064 and that states should make progress in controlling air pollution to meet this goal. The timeline is broken into

Figure 14: United States map of mandatory CIAs

10-year planning periods, and in each period, states must show reductions in emissions of haze-causing pollutants along a linear path, or glidepath, toward the 2064 end goal.

To meet the RHR planning requirements, states conduct analyses of visibility in each Class I area, identify the available reasonable measures to reduce haze, and implement those measures. The implemented measures establish the required Reasonable Progress Goals (RPG) for each Class I area. The RPGs are the visibility improvement benchmarks on the glidepath toward the long-term goal of natural visibility conditions by 2064.[40] The analysis, measures, and RPGs are the basis of the long-term strategy for the states, and this strategy must be included in the states’ SIPs. States are also required to assess progress halfway through the 10-year implementation period - a process that is intended to keep the states on target to meet the 10-year goals established for each Class I area.

1.E.1 Grand Canyon Visibility Transport Commission

The GCVTC was established by EPA in November of 1991, consisting of seven western governors (or their designees), five tribes, and five ex-officio members representing federal land management agencies and EPA. When establishing the GCVTC, EPA designated a transport region including seven western states: California, Oregon, Nevada, Idaho, Utah, Arizona,

[40] See Figure 15 for an RPG glidepath example of Bryce Canyon National Park, provided by the Western Regional Air Partnership (WRAP) Technical Support System.

Colorado, and New Mexico. Although a part of the Transport Region, the State of Idaho declined the invitation to participate in the GCVTC.

Although Congress required a commission to be established for Grand Canyon National Park, the member states agreed to expand the scope of the GCVTC to address all 16 of the CIAs on

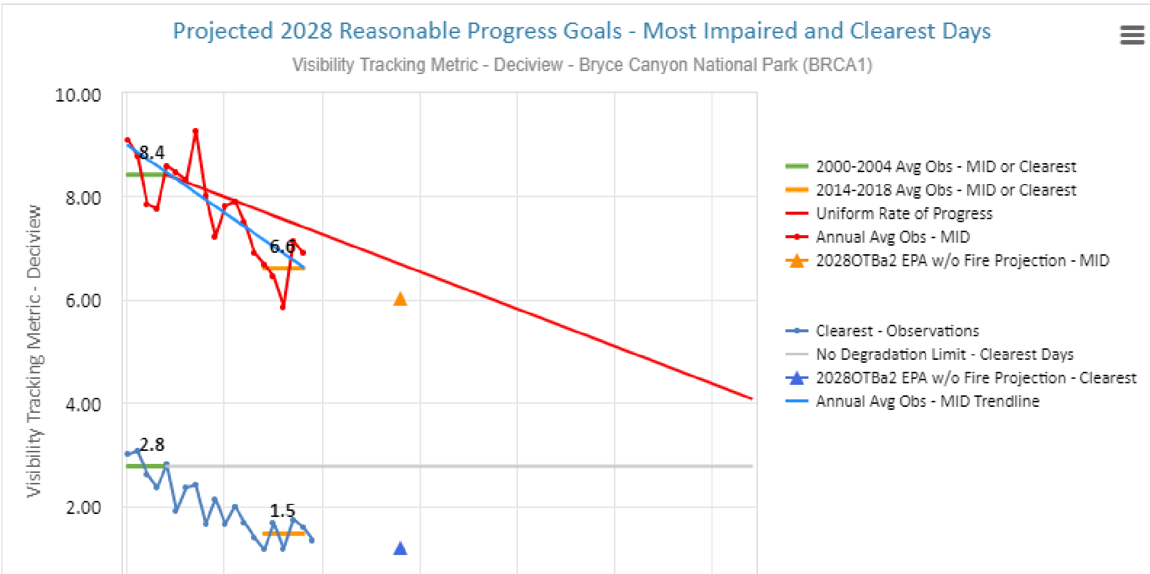

Figure 15: Regional haze glidepath for Bryce Canyon National Park tracking progress towards natural conditions in 2064

the Colorado Plateau. The GCVTC elected to use a stakeholder-driven process to accomplish its objectives. Ultimately, the organization included 200+ political, policy and technical stakeholders who staffed a variety of committees and subcommittees to perform policy analysis and technical studies, and to participate in the public debate. The GCVTC was funded by EPA grants and contributions from stakeholders, including substantial in-kind labor. During its four-and-one-half year development, the GCVTC was expanded to include the State of Wyoming and tribal leaders as members. The GCVTC appointed a Public Advisory Committee (PAC) representing broad stakeholder interests to provide input and feedback to the GCVTC. Many Utahns were members of the PAC, with two serving on the PAC Steering Committee, and one serving on the Executive Committee as Vice-Chair of the PAC. The 80+ member Public Advisory Committee developed a consensus report of recommendations for the GCVTC that was ultimately adopted by the GCVTC and submitted to EPA in June 1996.[41]

Recommendations of the GCVTC included the following:

- Policies based on energy conservation, increased energy efficiency, and promotion of the use of renewable resources for energy production;
- Careful tracking of emissions growth that may affect air quality in clean air corridors;

[41] The Grand Canyon Visibility Transport Commission. Recommendations for Improving Western Vistas (June 10, 1996) available at https://www.phoenixvis.net/PDF/GCVTCFinal.pdf

- Regional targets for SO_2 emissions with a backstop program, probably including a regional cap and possibly a market-based trading program;
- Cooperatively developed strategies, expanded data collection and improved modeling for reducing or preventing visibility impairment in areas within and adjacent to CIAs, pending further studies of sources adjacent to CIAs;
- Emissions cap for mobile sources at the lowest level (expected to occur in 2005) and establishment of a regional emissions budget, as well as the implementation of national strategies aimed at reducing tailpipe emissions;
- Further study to resolve issues regarding the modeled contribution to visibility impairment of dust from paved and unpaved roads;
- Continued bi-national cooperation to resolve data gaps and jurisdictional issues around emissions from Mexico;
- Programs to minimize emissions and visibility impacts and to educate the public about impacts from prescribed fire and wildfire, because emissions are projected to increase significantly through 2040; and
- Creation of an entity like the GCVTC to promote, support, and oversee the implementation of many of the recommendations in this report.

EPA initially proposed regional haze regulations in 1997.[42] The proposed regulations described a generic program to apply nationally and did not include provisions to address the recommendations of the GCVTC. The Western Governors' Association (WGA) engaged key stakeholders to develop a recommendation on how to transform the GCVTC recommendations into the regional haze regulations. WGA approved the stakeholders' recommendation and transmitted it to EPA in June 1998.[43] Based on this and other public input, EPA issued the final Regional Haze Rule in July 1999 with a national program (Section 308) that could apply to any state or tribe and an optional program (Section 309) relying on the work of the GCVTC that is available to the states and tribes in the nine-state GCVTC transport region.[44]

1.E.2 Western Regional Air Partnership

The GCVTC recognized the need for a long-term organization to address the policy and technical studies needed to address regional haze. The Western Regional Air Partnership (WRAP) was formed in September 1997 to fulfill this need. The WRAP's charter allows it to address any air quality issue of interest to WRAP members, though most current work is focused on developing the policy and technical work products needed by states and tribes in writing their regional haze SIPs and tribal implementation plans (TIPs). The WRAP has been co-chaired by the governor of Utah and the governor of the Acoma Pueblo. The WRAP Board is currently composed of representatives from 13 states, 13 tribes, the U.S. Department of Agriculture, the U.S. Department of the Interior, and the EPA. The WRAP operates on a consensus basis and receives financial support from EPA. The WRAP established stakeholder-

[42] Regional Haze Regulations, 62 Fed. Reg. 41138 (July 31, 1997) (proposed rule).
[43] Leavitt, M. O., Governor of Utah, Letter to EPA Administrator Browner on behalf of the Western Governors' Association, June 29, 1998.
[44] Regional Haze Regulations, 64 Fed. Reg. 35714 (July 1, 1999), codified at 40 C.F.R. pt. 51.

based technical and policy oversight committees to assist in managing the development process of regional haze work products. Stakeholder-based working groups and forums were established to focus on the policy and technical work products the states and tribes need to develop their implementation plans.

The WRAP developed and submitted an Annex to the GCVTC recommendations to define a voluntary program of SO_2 emission reduction milestones coupled with a backstop market-trading program to assure emission reductions. EPA proposed changes to the Regional Haze Rule to incorporate the GCVTC Annex, and the final revised rule was published on June 5, 2003.[45] The WRAP has completed a suite of products to support states and tribes developing GCVTC-based regional haze implementation plans.[46]

1.E.3 2003 Regional Haze SIP

On June 5, 2003, EPA approved the Annex and incorporated the stationary source provisions into the RHR In December 2003 the Utah Air Quality Board adopted Section XX of the SIP to address regional haze. This plan was based on the GCVTC recommendations and the Annex and contained a broad-based strategy to address the many source categories and pollutants that contributed to regional haze in Utah, including clean air corridors, fire, mobile sources, paved and unpaved road dust, pollution prevention and renewable energy programs, and stationary sources.

EPA's approval of the Annex was challenged in court, and on February 18, 2005, the DC Circuit Court of Appeals vacated EPA's 2003 rules.[47] The Court determined that EPA had required a BART demonstration in the Annex that was based on a methodology that had been vacated by the Court in 2002 in *American Corn Growers Association v. E.P.A.*, 291 F.3d 1 (D.C. Cir. 2002), decision. On October 13, 2006, EPA revised the RHR to establish the methodology for states to develop an alternative to BART that was consistent with the DC Circuit's 2005 decision.[48]

1.E.4 2008 Regional Haze SIP Revision

While most of the 2003 SIP remained unchanged, in 2008 the Utah Air Quality Board adopted revisions to the stationary source provisions of the SIP to meet the requirements of the revised RHR and to reflect changes in the number of states participating in the program. In addition to these changes, the rule required an update to the SIP in 2008 to address the BART requirement for NO_x and PM as well as an analysis of the impact of sources in Utah on CIAs outside of the Colorado Plateau.

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[45] Revisions to Regional Haze Rule to Incorporate SO_2 Milestones and Backstop Emissions Trading Program for Nine Western States and Eligible Indian Tribes Within That Geographic Area, 68 Fed. Reg. 33764 (June 5, 2003), codified at 40 C.F.R. pt. 51.

[46] Additional information about the WRAP can be found on the WRAP website at https://www.wrapair2.org/

[47] *See Ctr. for Energy & Econ. Dev. v. E.P.A.*, 398 F.3d 653 (D.C. Cir. 2005)

[48] *See* Regional Haze Regulations, 71 Fed. Reg. 60,612, 60,631 (Oct. 13, 2006), codified at 40 C.F.R. pt. 51.

1.E.5 2011 Regional Haze SIP Revision

The SO_2 milestones were updated in 2011 to reflect a reduced number of states participating in the program (Arizona elected to pursue a SIP under Section 308 of the RHR). In addition, the growth estimates for coal-fired utilities and the estimates for emission reductions due to BART were revised.

1.E.6 2015 Regional Haze SIP Revision

On June 4, 2015, Utah resubmitted its SIP for PM BART and submitted an alternative to BART for NO_x for PacifiCorp's Electrical Generating Units (EGUs). On January 14, 2016, EPA issued a proposed rule containing a proposal to approve the PM BART and a co-proposal to either approve or disapprove the BART Alternative for NO_x and to impose a Federal Implementation Plan (FIP) requiring BART for NO_x in the event of the disapproval.[49] On July 5, 2016, EPA issued the final rule disapproving the BART alternative for NO_x and approving the BART for the PM portion of the June 4, 2015 SIP.[50] To replace the disapproved BART alternative, EPA promulgated a FIP, requiring installation of Selective Catalytic Reduction (SCR) controls on the subject EGUs by August of 2021.[51]

Utah filed a lawsuit against EPA challenging the July 5, 2016 disapproval of BART Alternative for NO_x in the Tenth Circuit on September 1, 2016.[52] The parties engaged in settlement discussions to resolve the case administratively. As a result of the settlement negotiations, Utah conducted an additional technical analysis using the state-of-the-science model and methodologies to perform air quality model simulations.[53] Utah used the photochemical grid model Comprehensive Air Quality Model with Extensions (CAMx) to estimate and compare the potential visibility impacts at selected CIAs for different emissions scenarios considered for PacifiCorp's EGUs. The CAMx was used because it accounts for complex processes such as the chemistry, transport, and deposition of pollutants responsible for regional haze.

Utah came to the same conclusion employing the CAMx modeling: that its NO_x BART Alternative would provide greater reasonable progress toward natural visibility conditions than BART.[54] Utah revised the disapproved SIP to include this additional technical analysis and, after

[49] *See* Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 81 Fed. Reg. 2004 (Jan. 14, 2016) (proposed rule).
[50] *See* Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 81 Fed. Reg. 43894 (July 5, 2016), codified at 40 C.F.R. pt. 52.
[51] *See id.*, 81 Fed. Reg. at 43907.
[52] *See Utah v. E.P.A. et al.*, No. 16-9541 (10th Cir. Sept. 1, 2016).
[53] *See* Section 1.E.7 below for additional details.
[54] Staff Review Recommended Alternative to BART for NO_x at 5-2 (Jan. 14, 2019) ("The model results... indicate that the emissions modeled under the Utah SIP will not degrade visibility conditions relative to the Baseline scenario at any of the analyzed CIAs during either the 20% best or 20% worst visibility days.

public notice and comment, submitted the revised NO_x BART Alternative to EPA on July 3, 2019. Utah submitted a supplement to the July 2019 submission on December 3, 2019 on the issue unrelated to the initial disapproval—the requirement to report all deviations from compliance with the applicable requirements under BART and BART Alternative, including emission limits for PacifiCorp's EGUs. On January 22, 2020, EPA published a proposed rule to approve the July 2019 SIP submittal with December 2019 supplement.[55]

After EPA's public notice and comment, on November 27, 2020, EPA issued a final rule approving Utah's July 2019 SIP submittal and December 2019 supplement.[56] This concluded and resolved the litigation that Utah initiated on September 1, 2016. The Tenth Circuit dismissed the case and issued a mandate on January 11, 2021.[57] EPA's November 27, 2020 final rule is currently challenged in the Tenth Circuit by the conservation organizations (HEAL Utah, National Parks Conservation Association, Sierra Club, and Utah Physicians for a Healthy Environment).[58] The lawsuit was filed on January 19, 2021.[59]

1.E.7 2019 Regional Haze SIP Revision

In the 2019 SIP revision, Utah used dispersion modeling and the two-prong test prescribed by the RHR[60] to demonstrate that the proposed alternative to BART does show greater progress than the most stringent NO_x controls (installation of SCR). The two prongs that Utah had to satisfy are (1) that visibility does not decline in any Class I area; and (2) that there is an overall improvement in visibility determined by comparing the average differences between BART and the BART Alternative over all affected CIAs.

The two-prong test was an objective pass-fail test which Utah's BART Alternative met. EPA proposed approval of this latest SIP on January 22, 2020.[61]EPA issued final approval of the 2019 SIP revision on November 27, 2020 with effective date of December 28, 2020.[62] In the final rule EPA concluded "that Utah's NO_X BART Alternative achieves greater reasonable progress under 40 CFR 51.308(e)(2) and (3)."[63] With the final approval, EPA also found that "Utah's SIP fully satisfies the requirements of section 309 of the Regional Haze Rule and

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The modeling results also show that, on average, visibility improvement at the analyzed CIAs is greater under the Utah SIP than the USEPA FIP scenarios during both the 20% best and 20% worst visibility days.").

[55] *See* Approval and Promulgation of Air Quality Implementation Plans; Utah; Regional Haze State and Federal Implementation Plans, 85 Fed. Reg. 3558 (Jan. 22, 2020) (proposed rule).

[56] Approval and Promulgation of Air Quality Implementation Plans; Utah; Regional Haze State and Federal Implementation Plans, 85 Fed. Reg. 75860 (Nov. 27, 2020), codified at 40 C.F.R. pt. 52.

[57] *See* Order, *Utah v. E.P.A. et al.*, No. 16-9541 (10th Cir. Jan. 11, 2021).

[58] *See HEAL Utah et al. v. E.P.A. et al.*, No. 21-9509 (10th Cir. Jan 19, 2021).

[59] *See* Petition for Review, *HEAL Utah et al.*, No. 21-9509 (10th Cir. Jan. 19, 2021).

[60] 40 CFR 51.308€ (3)

[61] *See* 85 Fed. Reg. 3558.

[62] *See* 85 Fed. Reg. 75860.

[63] *Id.*, 85 Fed. Reg. at 75861.

therefore the State has fully complied with the requirements for reasonable progress, including BART, for the first implementation period."[64]

1.F General Planning Provisions

1.F.1 Regional Haze Program Requirements

The program requirements of the RHR[65] are identified in Subsection 51.308(f) which lists the requirements for haze SIP updates, including a reference to the requirements in Subsection 51.308(d). In addition to re-evaluating all elements required in subsection (d), the states must also do the following:

- Assess current visibility conditions for the most impaired and least impaired days.
- Address actual progress made towards natural conditions during the previous implementation period.
- Determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period.
- Affirm or revise reasonable progress goals according to procedures in paragraph (d).

As noted above, the section addressing the requirements for the SIP revisions references the requirements of subsection (d). The subsection (d) requirements are as follows: requirements:

- Establishing reasonable progress goals for the implementation period, including the four-factor analysis.
- Determining current visibility conditions and comparing to natural conditions.
- Developing long-term strategies to reduce emissions that contribute to visibility impairment.
- Submitting a monitoring strategy.

40 CFR 51.308(f)(5) requires states to address the requirements of Subsections 51.308(g)(1)-(5) in the 2021 plan revision. According to the requirements of 40 CFR 51.308(g), states shall submit periodic reports that describe progress toward the natural visibility goals. Therefore, this RH SIP submittal also serves as a progress report addressing the period since Utah's September 18, 2017 progress report. The RHR requires that subsequent progress reports are due by January 31, 2025, July 31, 2033, and every 10 years thereafter.

1.F.2 SIP Submission and Planning Commitments

This SIP revision meets the requirements of the EPA's RHR and the CAA. Elements of this SIP address the core elements required by 40 CFR Section 51.308(f)(3)—the establishment of RPGs and measures that Utah will take to meet the RPGs. This SIP revision also addresses 40 CFR 51.308(f)(2) (long-term strategy for regional haze) and 40 CFR 51.308(i)(2) (state

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64 *Id.*

65 40 CFR 51.308

coordination with the FLMs) and commits to develop future plan revisions and adequacy determinations as necessary.

The State of Utah commits to participate in a regional planning process, as a member state through the Western States Air Resource Council (WESTAR) and as a partner in WRAP. WESTAR is a partnership of 15 western states formed to promote the exchange of information, serve as a forum to discuss western regional air quality issues, and share resources for the common benefit of the member states. WRAP is a voluntary partnership of state, tribes, FLMs, local air agencies, and the EPA whose purpose is to understand current and evolving regional air quality issues in the West. The regional planning process describes the process, goals, objectives, management and decision-making structure, and deadlines for completing significant technical analyses of the regional group. To assist in making sound planning decisions, Utah has assisted the regional planning organization to complete regional analyses that include certain methods, inputs, and resources. Utah commits to continue regional participation through future SIPs.

Pursuant to the Tribal Authority Rule[66], any Tribe whose lands are within the boundaries of the State of Utah have the option to develop a regional haze Tribal Implementation Plan (TIP) for their lands to assure reasonable progress in the twelve CIAs in Utah. As such, no provisions of this Implementation Plan shall be construed as being applicable to tribal lands.

1.F.3 Utah Statutory Authority

The Utah Air Conservation Act[67] gives the Utah Air Quality Board authority to make rules pertaining to air quality activities.[68]

An administrative rule serves two purposes:

- A properly enacted administrative rule has the binding effect of law. Therefore, a rule affects the regulated entities and citizens as much as a statute passed by the Legislature.
- An administrative rule informs citizens of actions a state government agency will take or how a state agency will conduct its business.

This SIP is a compilation of analyses under Utah's statutory authority that satisfies the requirements of Sections 110 and 169 of the CAA.

Indian Tribes: Air Quality Planning and Management, 63 Fed. Reg. 7254 (Feb. 12, 1998).
[67] Utah Code Ann. §§ 19-2-101 through 19-2-304 (West 2021).
[68] *See id*. § 19-2-104.

Chapter 2: Utah Regional Haze SIP Development Process

This SIP addresses regulatory requirements of the second planning period by screening facilities with the most impact on Utah's CIAs, conducting and evaluating the four-factor analysis,[69] and making controls determinations based on this analysis. The current visibility conditions in relation to our Uniform Rate of Progress (URP) goals were also analyzed with the modeled data analysis tools provided by the WRAP Technical Support System (TSS).

Utah's SIP development process included consultation with industry stakeholders, environmental advocate stakeholders, regional states, WESTAR, WRAP, FLMs from the National Parks Service and the US Forest Service, and EPA's Region 8 office. Utah also consulted members of other state agencies including the Department of Energy Development and Office of Public Utilities. This chapter outlines Utah's consultation and communications with these entities. For additional details regarding individual consultation, see Chapter 9 Consultation, Public Review, Commitment to further Planning.

After initial consultation, Utah submitted the second planning period RH SIP to the FLMs, EPA, and Tribes of Utah on December, 8, 2021 for their mandatory 60-day comment period. After the comment period, the SIP was submitted to Utah Air Quality Board for the April 6th, 2022 Utah Air Quality Board meeting. The Board then proposed the SIP for public comment on May 1st, 2022 for the required 30 days. Utah then submitted the final SIP to the EPA on August 1, 2022.

2.A WRAP Engagement

During this second planning period, the WRAP Regional Haze Planning Work Group (RHPWG)[70] has helped create a framework for regional haze planning for all 15 participating states as well as the City of Albuquerque within the WESTAR and WRAP region. This initiative included regular meetings to discuss regional haze planning, encourage coordination among states, and offer training opportunities. WRAP has also been responsible for the WRAP TSS which is an online portal to the technical and analytical results created from technology development from Colorado State University (CSU) and the Cooperative Institute for Research in the Atmosphere (CIRA). TSS is the source of the key summary analytical results and methods for the required technical elements of the RHR contained within this SIP including:

- Inventories: current and future (growth projections methodologies by source categories)
- Development of a transparent and complete monitoring data metric for planning and model projection purposes
- Database management (including the TSS database)

[69] For purposes of this document, the Four-Factor Analysis is defined as the analysis required by 40 C.F.R. § 51.308(d)(1)(i)(A).
[70] More information on the Regional Haze Planning Work Group can be found at https://www.wrapair2.org/RHPWG.aspx

- Four-Factor Analysis for control measures
- Regional photochemical modeling
- Assessment of "unknowns" and uncertain categories (natural conditions, international emissions, fire, and dust emission, etc.)
- Development of RH SIP package content and progress report template
- Development of control strategies menu for major western state sources

For additional information on the origins of WRAP, see Section 1.E.2.

2.A.1 Technical Information and Data: WRAP TSS2.0

The WRAP TSS 2.0 is the data warehouse and online portal used by air quality planners to evaluate the technical data and analytical results to support regional haze implementation plans. The TSS 2.0 is a "system of systems" that integrates capabilities from many systems, including systems focused on: monitoring data analysis efforts, emissions data management systems, fire emissions tracking systems, photochemical aerosol regional modeling analyses, and visualization and summary data analyses.[71] These diverse data sets can be analyzed through the TSS and the resultant outputs can be downloaded for use in SIP reports. This SIP submittal relies on the data stored in and retrieved from the TSS 2.0 system.

2.B Consultation with Federal Land Managers

The federal land management agencies with jurisdiction over mandatory CIAs in the West include the National Park Service (NPS), U.S. Forest Service (U.S. Department of Agriculture) (USFS), and the Fish and Wildlife Service (FWS). FLMs have a critical role in protecting air quality in national parks, wilderness, and other federally protected areas. They have an affirmative responsibility to protect air quality related values, including visibility, in all CIAs.[72] Utah primarily meets with the NPS and USFS for RH planning.

States must provide the FLMs with an opportunity for an early in-person consultation about the state's long-term strategy to reduce emissions.[73] This consultation should happen early enough in the process so that the information and recommendations provided by the FLMs can meaningfully inform the State's decisions.[74] The opportunity for consultation is sufficient if the consultation happened at least 120 days prior to any public hearing or other public comment opportunity on SIP or SIP revision.[75] The opportunity for consultation must also be provided no less than 60 days prior to said public hearing or public comment opportunity.[76]

[71] https://views.cira.colostate.edu/tssv2/About/Default.aspx
[72] *See* 40 C.F.R. § 51.166(p)(2).
[73] *See* 40 C.F.R. § 51.308(i)(2).
[74] *See id*.
[75] *See id*.
[76] *See id*.

This consultation must include the opportunity for the affected FLMs to discuss their:

- Assessment of impairment of visibility in any mandatory CIA; and
- Recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment.[77]

FLM of any mandatory Class I area can submit any recommendations on the implementation of this subpart (40 C.F.R. Part 51, Subpart P: Protection of Visibility) including, but not limited to:

i. Identification of impairment of visibility in any mandatory CIA(s); and
ii. Identification of elements for inclusion in the visibility monitoring strategy required by § 51.305.[78]

Utah has engaged with the FLMs and shared the RH SIP with them on December 8, 2021. See Chapter 9 Consultation, Public Review, Commitment to Further Planning for full documentation of Utah's consultation with the FLMs during this implementation period.

Numerous opportunities were provided through the WRAP for states and FLMs to participate fully in the development of technical documents included in this SIP. This included the ability to review and comment on these analyses, reports, and policies. A summary of the WRAP-sponsored meetings and conference calls is provided on the WRAP website[79].

2.C Collaboration with Tribes

Tribal governments are responsible for coordinating with federal and state governments to protect air quality on their sovereign lands and to ensure emission sources on tribal lands meet federal requirements. The federally recognized tribes in Utah include the Paiute Indian Tribe, the Skull Valley Band of Goshute Indiana, and the Ute Indian Tribe of the Uintah and Ouray Reservation. The sources located on tribal lands are considered federal jurisdiction. For example, The Bonanza power plant, located on "Indian Country" in the Uinta Basin, has a Q/d value large enough to require a Four-Factor Analysis, but is not under the jurisdiction of the Utah Department of Environmental Quality. In order to further the environmental justice initiative in Utah, UDAQ shared its RH SIP draft with the tribes of Utah at the same time it was shared with the FLMs and EPA for a 60-day review on December 8, 2021.

2.D Consultation with Other States

States are required to share information with other states that have CIAs that are reasonably anticipated to be impacted by each other's emissions. States are also required to evaluate, though not necessarily implement, control measures requested by other states and document actions taken to resolve disagreements. The TSS 2.0 analyses tools, including emissions tools and source apportionment modeling results, aid states to determine if an in-state source could be impacting an out-of-state Class I area. Utah consulted with neighboring states, both through

[77] *See id.*, § 51.308(i)(2)(i) and (ii).
[78] *See id.*, § 51.308(i)(1)(i) and (ii).
[79] More information on WRAP-sponsored meetings and conference calls is available at https://www.wrapair2.org/RHPWG.aspx.

webinars and calls organized through the WRAP, and via state-to-state communication, to address the requirements of the RHR for coordinated emissions control strategies between states. Specifically, 40 CFR § 51.308(f)(2)(ii) requires that Utah consult with other states that have emissions that are reasonably anticipated to contribute to visibility impairment in Utah CIAs to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

WRAP conducted technical analyses to evaluate interstate emissions impacts. These analyses include source apportionment modeling and area of influence/weighted emissions potential (AOI/WEP) analyses. Source apportionment modeling is used to identify states and sectors that are contributing haze. AOI/WEP analyses can identify what significant emission sources are upwind from a Class I area. Utah discussed the results of these analyses with surrounding states. Due to all of Utah's CIAs visibility being at or below their projected glidepath goals towards natural conditions in 2064, UDAQ will not ask for any additional controls from other states that may impact Utah's visibility in CIAs. Refer to sections 6.A.1 and 6.A.2 for a detailed analysis on out of state impacts on Utah's CIA's and Utah's impacts on out of state CIAs.

Utah has met with Colorado, New Mexico, Arizona, and Wyoming directly as well as attended Region 8, WRAP, WESTAR, and Four Corners States meetings as part of the second planning period SIP development. For additional details regarding individual consultation, see Chapter 9 as well as Appendix B or Utah's interstate consultation agreements with surrounding states.

2.E Public and Stakeholder Consultation

Many different agencies and interests come together to develop a RH SIP. Prior to formal public review and EPA action, states should communicate regularly with industry and the public. Utah communicated regularly with the regulated industry, including the sources that may be impacted by the Four-Factor Analysis, environmental advocates, as well as members of the public. Utah holds six meetings each for the industry stakeholders and environmental advocates. For additional details regarding stakeholder consultation, see Chapter 9.

Chapter 3: Progress to Date

3.A Embedded Progress Report Requirements

Section 51.308(f)(5) of the RHR requires a state to address the requirements of subsections 51.308 (g)(1) through (5) in the plan revision. By fulfilling this requirement, the plan revision due in 2021 will also serve as a progress report for the period since submission of the progress report for the first implementation period. The progress report for the first implementation period included visibility levels, emissions, and implementation status up to a date prior to submittal.[80]

This chapter is meant to inform the public and EPA about implementation activities since the last regional haze SIP submission.

3.A.1 Implementation status of all measures in first planning period[81]

The RHR[82] requires certain major stationary sources to evaluate, install, operate and maintain BART technology or an approved BART alternative for NO_x and PM emissions. The State of Utah chose to evaluate BART for PM under the case-by-case provisions of 40 CFR 51.308(e)(1) and BART for NO_x through alternative measures[83]. BART for SO_2 is addressed through an alternative program[84] that is described in Part E of the 2019 Regional Haze SIP.

40 CFR 51.308(e)(1)(ii) requires states to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory CIA.

Four BART-eligible electric generating units were identified in the State of Utah: PacifiCorp's Hunter Units 1 and 2 and Huntington Units 1 and 2. The units are located at fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input, one of the 26 specific BART source categories. The units had potential emissions greater than 250 tons per year of visibility impairing pollutants. The units had commenced construction within the BART time frame of August 7, 1962 to August 7, 1977. PacifiCorp Hunter Units 1 and 2 and Huntington Units 1 and 2 replaced first generation low-NO_x burners with Alstom TSF 2000TM low-NO_x firing system and installation of two elevations of separated overfire air with an emission limit of 0.26 lb./MMBtu on a 30-day rolling average.

In addition, PacifiCorp Hunter Unit 3 (not subject-to-BART) replaced first generation low-NO_x burners with improved low-NO_x burners with overfire air with an emission limit of 0.34 lb./MMBtu

[80] The 2017 Regional Haze Guidance document can be found at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[81] (40 CFR 51.308(g)(1))
[82] 40 CFR 51.308(e) and 40 CFR 51.309(d)(4)(vii)
[83] 40 CFR 51.308(e)(2) and (3)
[84] 40 CFR 51.309

on a 30-day rolling average and PacifiCorp Carbon Units 1 and 2 (not subject-to-BART) were permanently retired by August 15, 2015.

Table 1: 30-day Rolling Average Emission Limits for the Retrofitted Hunter and Huntington Units

Units	Utah Permitted Limits		
	SO_2 (lb./MMBtu)	NO_x (lb./MMBtu)	PM (lb./MMBtu)
Hunter 1	0.12	0.26	0.015
Hunter 2	0.12	0.26	0.015
Hunter 3		0.34	
Huntington 1	0.12	0.26	0.015
Huntington 2	0.12	0.26	0.015

3.A.2 Summary of emission reductions achieved by control measure implementation[85]

The enforceable retirement of Carbon Units 1 and 2 resulted in SO_2 reductions of 3,388 tons/year from Unit 1 and 4,617 tons per year from Unit 2, resulting in a total of 8,005 tons per year. Utah's emissions reductions are further detailed in Chapter 5.

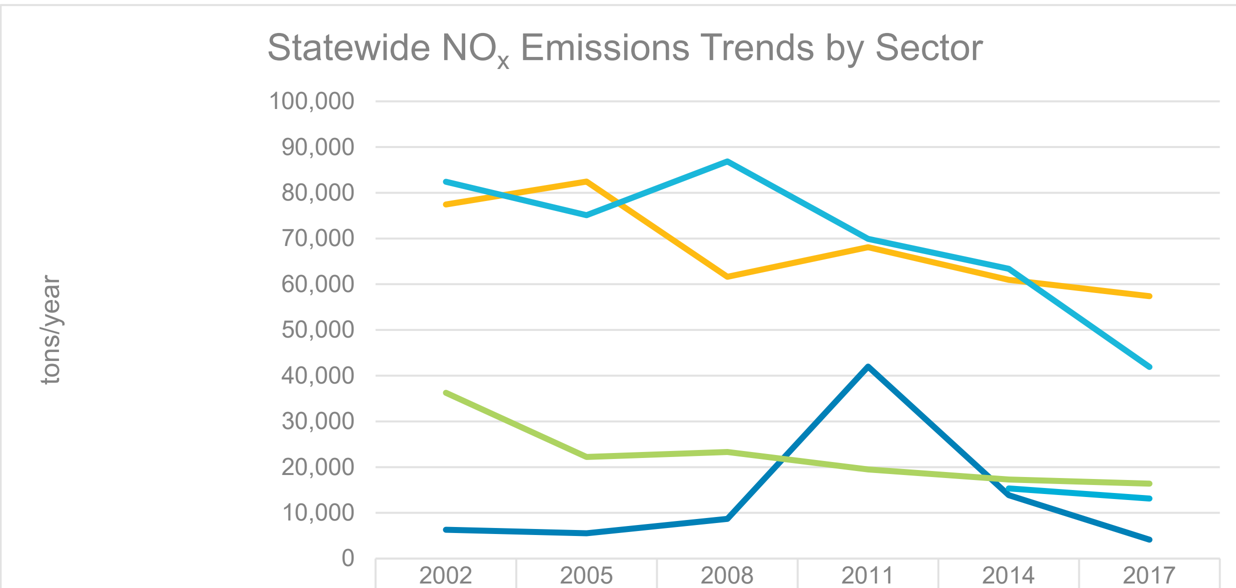
3.A.3 Assessment of visibility conditions[86]

Please refer to Chapter 4 for information regarding Utah's visibility analyses.

[85] (40 CFR 51.308(g)(2)(5))
[86] (40 CFR 51.308(g)(3))

3.A.4 Analysis of any changes in emissions from all sources and activities within the state[87] ~~[88]~~

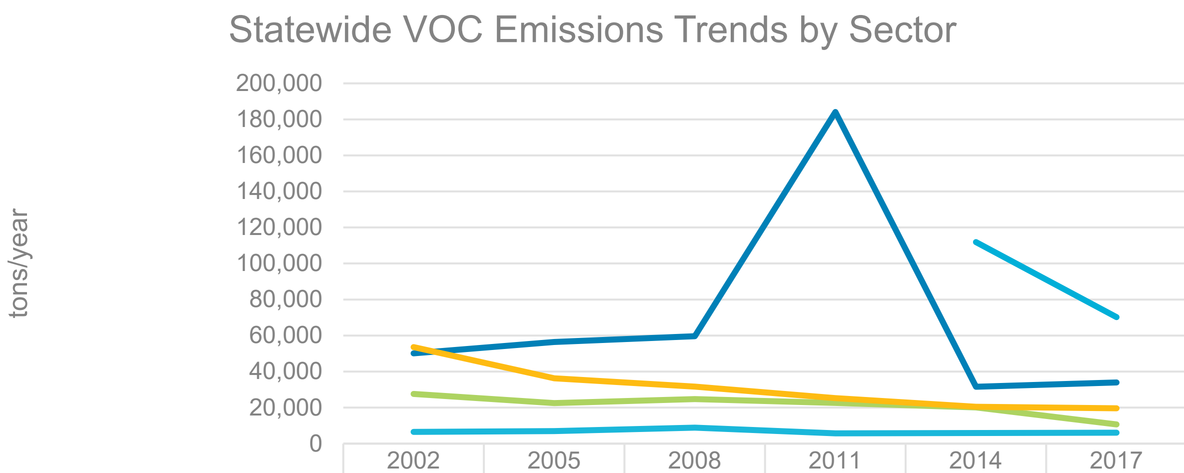
The following figures show Utah's statewide total emissions trends by sector from 2002 to 2017. This data comes from Utah's statewide emissions inventories. In 2011, there are certain spikes in emissions for area source emissions due to inventory method changes and an increase in the amount of Source Classification Codes (SCCs) defining area sources. UDAQ notes that inventory methodologies have changed over time and the emissions inventories based on WRAP modeling data in section 5.E may be more useful for comparing historical and recent emissions to future projections for the purposes of satisfying the requirements of 40 CFR 51.308(g)(4).



	2002	2005	2008	2011	2014	2017
Area Source	6,294	5,536	8,664	41,987	13,848	4,134
Area Source - Oil & Gas					15,340	13,130
Non-Road Mobile	36,257	22,212	23,296	19,507	17,288	16,388
On-Road Mobile	77,437	82,449	61,634	68,109	60,952	57,387
Point Source	82,421	75,102	86,857	69,913	63,370	41,903

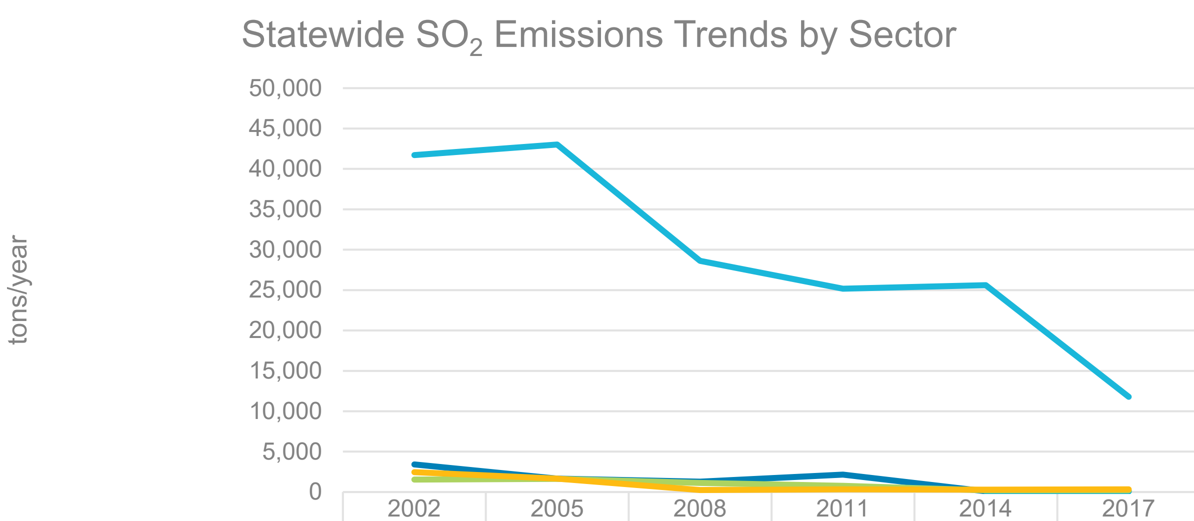
Figure 16:Statewide NO_x Emissions Trends by Sector

[87] (40 CFR 51.308(g)(4))



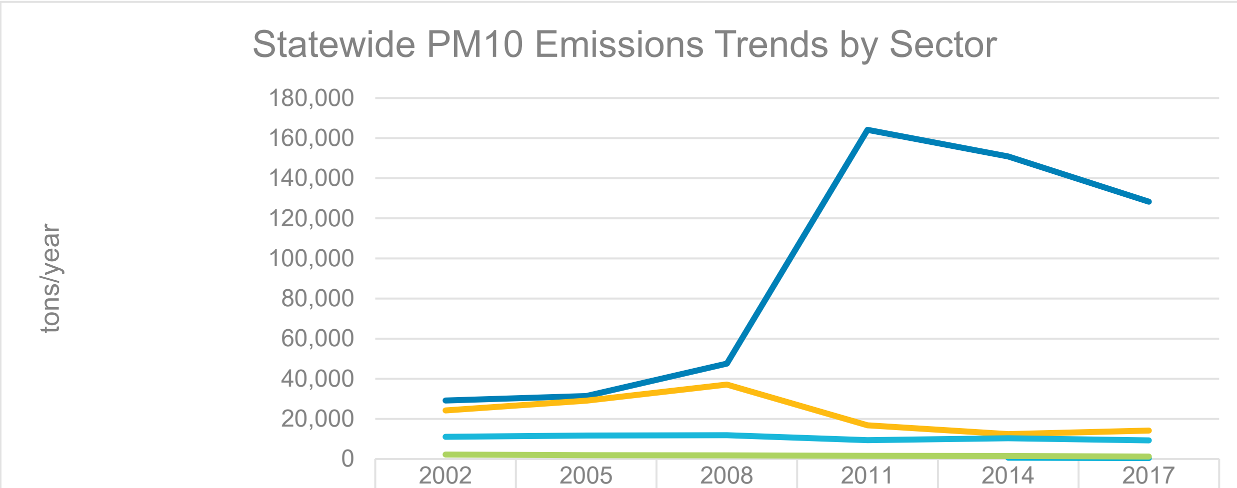
	2002	2005	2008	2011	2014	2017
Area Source	50,152	56,416	59,587	184,099	31,574	33,935
Area Source - Oil & Gas					111,880	70,217
Non-Road Mobile	27,584	22,479	24,677	22,629	20,066	10,671
On-Road Mobile	53,582	36,278	31,673	25,282	20,487	19,619
Point Source	6,555	6,963	8,872	5,707	5,899	6,104

Figure 17: Statewide VOC Emissions Trends by Sector



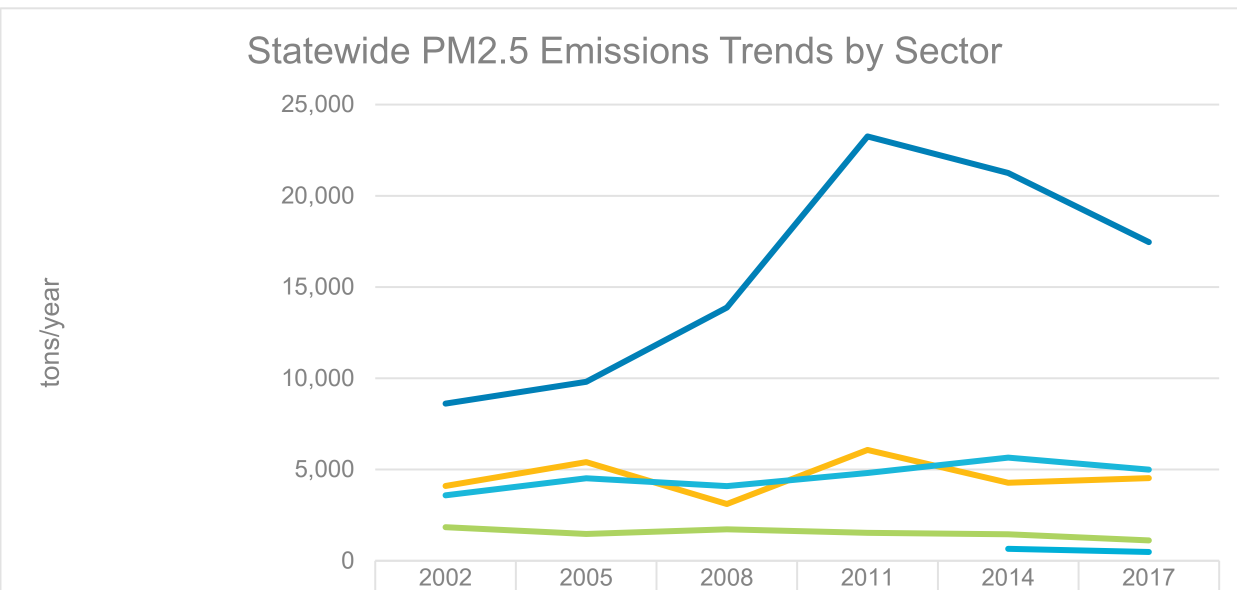
	2002	2005	2008	2011	2014	2017
Area Source	3,416	1,660	1,284	2,156	89	117
Area Source - Oil & Gas					92	74
Non-Road Mobile	1,536	1,627	1,132	759	214	220
On-Road Mobile	2,458	1,667	247	333	295	327
Point Source	41,704	43,019	28,621	25,170	25,600	11,786

Figure 18: Statewide SO2 Emissions Trends by Sector



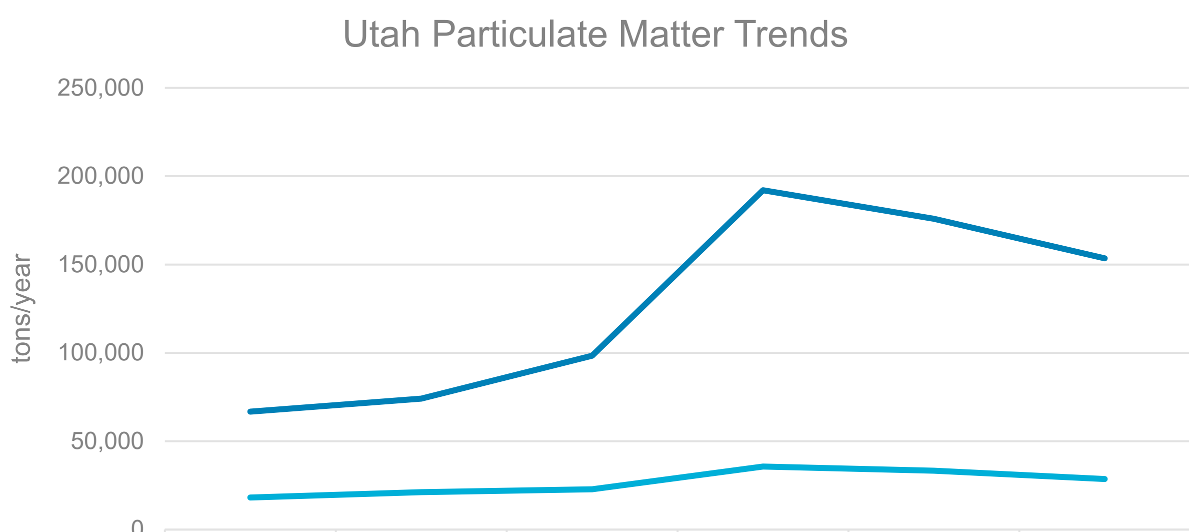
	2002	2005	2008	2011	2014	2017
Area Source	29,181	31,416	47,552	164,142	150,865	128,303
Area Source - Oil & Gas					675	483
Non-Road Mobile	2,243	1,892	1,841	1,627	1,528	1,230
On-Road Mobile	24,246	29,077	37,137	16,856	12,426	14,212
Point Source	11,080	11,739	11,877	9,443	10,397	9,303

Figure 19: Statewide PM_{10} Emissions Trends by Sector



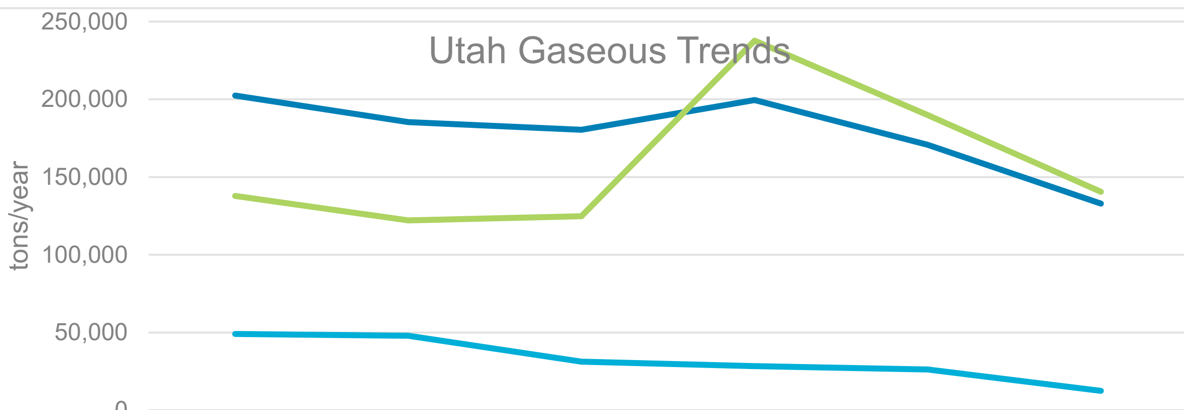
	2002	2005	2008	2011	2014	2017
Area Source	8,613	9,806	13,878	23,254	21,254	17,460
Area Source - Oil & Gas					656	483
Non-Road Mobile	1,840	1,473	1,727	1,533	1,449	1,117
On-Road Mobile	4,101	5,404	3,111	6,074	4,278	4,532
Point Source	3,587	4,518	4,089	4,809	5,653	4,998

Figure 20: Statewide $PM_{2.5}$ Emissions Trends by Sector



	2002	2005	2008	2011	2014	2017
PM10	66,751	74,125	98,407	192,067	175,891	153,531
PM2.5	18,142	21,201	22,806	35,670	33,290	28,589

Figure 21: Utah Particulate Matter Trends



	2002	2005	2008	2011	2014	2017
NOx	202,409	185,300	180,451	199,517	170,798	132,942
SO2	49,113	47,975	31,283	28,418	26,290	12,524
VOC	137,873	122,136	124,809	237,717	189,907	140,545

Figure 22: Utah Gaseous Trends

3.A.5 Assessment of any changes in emissions from within or outside the state.[89]

The Center for the New Energy Economy (CNEE) at Colorado State University conducted an analysis of current and future emissions of NO_x and SO_2 from fossil-fueled EGUs in 13-Western states1 for WESTAR and WRAP.[90] WRAP state air quality staff and representatives of Western electric utilities actively participated in the project and helped develop the study parameters, including information needed for Western regional air quality analyses and planning under the federal Clean Air Act.

SO_2 and NO_x emissions from the Western power sector have decreased dramatically over the last 20 years. As shown in Figure 23, 2018 EGU emissions of SO_2 were 84% below 1998 levels and NO_x emissions were 71% below 1998.

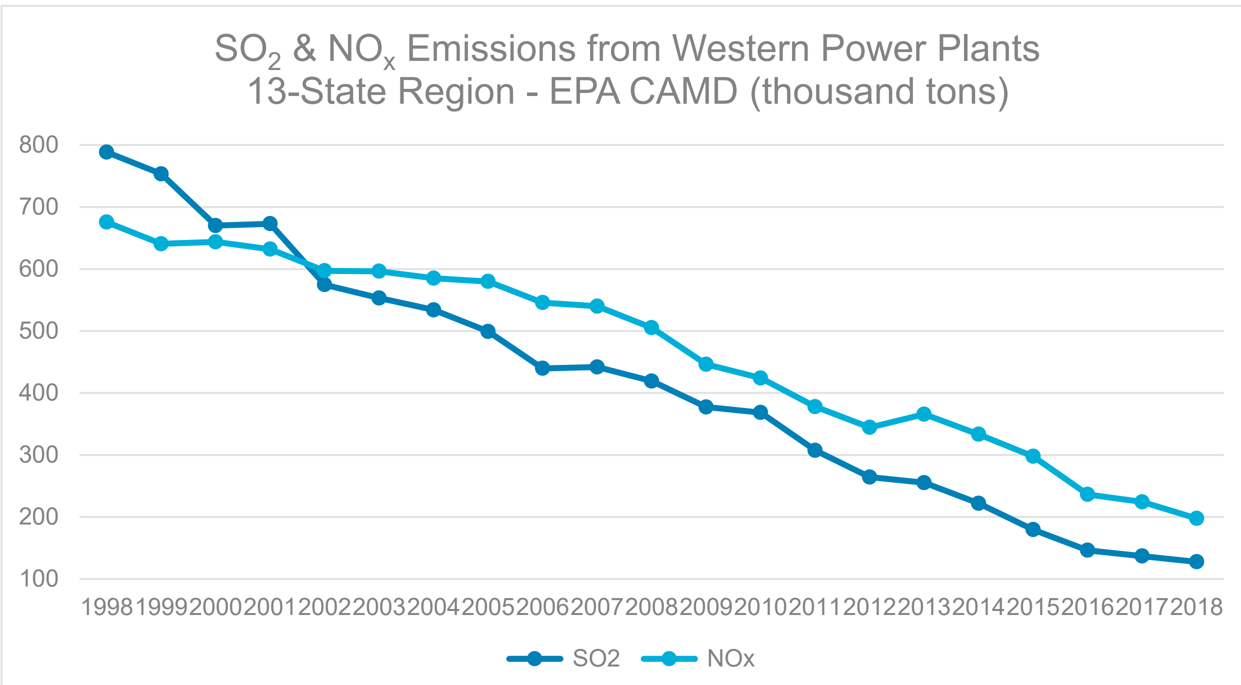


Figure 23: SO_2 and NO_x Emissions Trends for Western Power Plants[1]

Table 2 below shows that 29 of the 84 coal units operating in the West in 2018 have plans (not all federally enforceable) to retire by 2028. Emissions from these units were omitted from the 2028 projections produced by the CNEE, though some states opted to include emissions for some of the listed EGUs in the final WRAP 2028OTBa2 projections due to uncertainties about firm closures (e.g., North Valmy, San Juan Generating Station, etc.).

[89] (40 CFR 51.308(g)(5))
[90] The Analysis of EGU Emissions for Regional Haze Planning by the CNEE can be found at http://www.wrapair2.org/%5C/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf

Table 2: Western Coal Unit Retirement and Control Summary

State	Facility Name	Unit ID	Operating Year	Retirement Year	Notes
PLANNED RETIREMENTS - NO POST-COMBUSTION CONTROL FOR NO=x					
AZ	Cholla	1	1962	2025	APS IRP
AZ	Cholla	3	1980	2025	APS IRP
AZ	Cholla	4	1981	2025	PAC IRP
AZ	Navajo Generating Station	1	1974	2019	SRP IRP
AZ	Navajo Generating Station	2	1975	2019	SRP IRP
AZ	Navajo Generating Station	3	1976	2019	SRP IRP
CO	Comanche (470)	1	1973	2022	Xcel Colorado Energy Plan
CO	Comanche (470)	2	1975	2025	Xcel Colorado Energy Plan
CO	Craig	C1	1980	2025	Legal/Regulatory
CO	Nucla	1	1991	2022	Legal/Regulatory
CO	Valmont	5	1964	2017	Retired
MT	Colstrip	1	1975	2022	Legal/Regulatory
MT	Colstrip	2	1976	2022	Legal/Regulatory
NM	San Juan	1	1976	2022	PNM IRP (SNCR)
NM	San Juan	2	1973	2017	Retired
NM	San Juan	3	1979	2017	Retired
NM	San Juan	4	1982	2022	PNM IRP
NV	North Valmy	1	1981	2025	NV IRP (2019 per ID Power?)
NV	North Valmy	2	1985	2025	NV IRP
NV	Reid Gardner	4	1983	2017	Retired
OR	Boardman	1SG	1980	2021	Legal/Regulatory
UT	Intermountain	1SGA	1986	2025	Planned (new gas?)
UT	Intermountain	2SGA	1987	2025	Planned (new gas?)
WA	Centralia	BW21	1972	2021	Legal/Regulatory (12/31/2020)
WA	Centralia	BW22	1973	2026	Legal/Regulatory (12/31/2025)
WY	Naughton	3	1971	2018	PAC IRP - gas in 2019?
MT	Hardin			2017	
POTENTIAL RETIREMENTS - NO POST-COMBUSTION CONTROL FOR NO_x					
AZ	Coronado Generating Station	U1B	1979		Retire or install SCR in 2025
UT	Bonanza	1-Jan	1986	2030	Coal consumption cap
WY	Dave Johnston	BW41	1959	2027	PAC IRP
WY	Dave Johnston	BW42	1961	2027	PAC IRP
WY	Dave Johnston	BW43	1964	2027	PAC IRP

State	Facility Name	Unit ID	Operating Year	Retirement Year	Notes
WY	Dave Johnston	BW44	1972	2027	PAC IRP
WY	Jim Bridger	BW71	1974	2028	PAC IRP (SCR req'd 2022)
WY	Naughton	1	1963	2029	PAC IRP
WY	Naughton	2	1968	2029	PAC IRP
POST 2028 RETIREMENT DATE - SCR INSTALLED					
AZ	Coronado Generating Station	U2B	1980		SCR 2014
AZ	Springerville Generating Station	4	2009		SCR
AZ	Springerville Generating Station	TS3	2006		SCR
CO	Comanche (470)	3	2010		SCR
CO	Craig	C2	1979		SCR 2017
CO	Hayden	H1	1965	2030	Xcel IRP - SCR in 2015
CO	Hayden	H2	1976	2036	Xcel IRP - SCR 2016
CO	Pawnee	1	1981	2034	Xcel IRP - SCR 2014
NM	Four Corners Steam Elec Station	4	1969		2031 per TEP&PNM - SCR 2017
NM	Four Corners Steam Elec Station	5	1970		2031 per TEP&PNM - SCR 2017
NV	TS Power Plant	1	2008		SCR
WY	Dry Fork Station	1	2011		SCR
WY	Jim Bridger	BW73	1976	2037	PAC IRP - SCR 2015
WY	Jim Bridger	BW74	1979	2037	PAC IRP - SCR 2016
WY	Laramie River	1	1981		SCR 2019
WY	Wygen I	1	2003		SCR
WY	Wygen II	1	2008		SCR
WY	Wygen III	1	2010		SCR
AZ	Apache Station	3	1979		SNCR 2017
CO	Craig	C3	1984		SNCR 2017
WY	Laramie River	2	1981		SNCR 2018
WY	Laramie River	3	1982		SNCR 2018
POST 2028 RETIREMENT DATE - NO POST COMBUSTION CONTROLS FOR NO_x					
AZ	Springerville Generating Station	1	1985		
AZ	Springerville Generating Station	2	1990		
CO	Martin Drake	6	1968		
CO	Martin Drake	7	1974		
CO	Rawhide Energy Station	101	1984		

State	Facility Name	Unit ID	Operating Year	Retirement Year	Notes
CO	Ray D Nixon	1	1980		
MT	Colstrip	3	1984		
MT	Colstrip	4	1986		
MT	Lewis & Clark	B1	1958		
NM	Escalante	1	1984		
UT	Hunter	1	1978	2042	PAC IRP - Haze Lawsuit
UT	Hunter	2	1980	2042	PAC IRP - Haze Lawsuit
UT	Hunter	3	1983	2042	PAC IRP
UT	Huntington	1	1977	2036	PAC IRP - Haze Lawsuit
UT	Huntington	2	1974	2036	PAC IRP - Haze Lawsuit
WY	Jim Bridger	BW72	1975	2032	PAC IRP (SCR Req'd 2021)
WY	Neil Simpson II	1	1995		
WY	Wyodak	BW91	1978	2039	PAC IRP - Haze Lawsuit

Emissions from coal units that will retire by 2028 comprised 27% of the SO_2 and 34% of the NO_x emitted in 2018 by all EGUs (coal and gas) in the 13-state Western region.[91] Figure 24 below shows the portion of EGU emissions represented by remaining fossil units and retiring coal units. Table 3 below contains data compiled by WESTAR-WRAP showing the changes in emissions from 1996-2018 and percent change throughout the GCVTC states.

[91] The Analysis of EGU Emissions for Regional Haze Planning by the CNEE can be found at http://www.wrapair2.org/%5C/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf

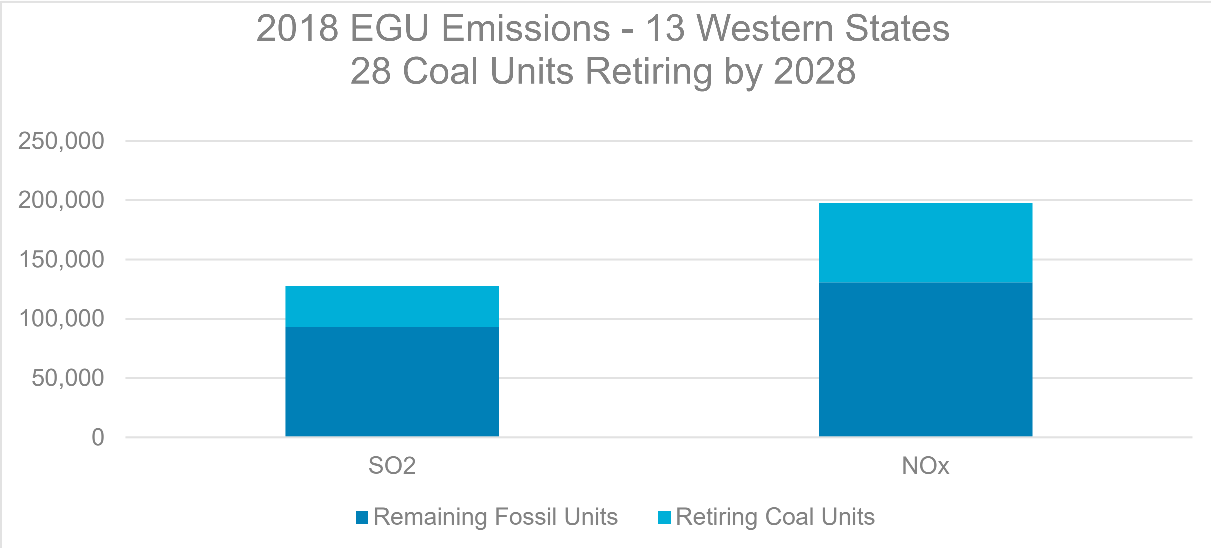


Figure 24: Remaining and Retiring EGU Emissions Apportionment

Table 3: Changes in Emissions from 1996 - 2018 for 9 GCVTC States

Year	VOC	NO_x	SO_2	$PM_{2.5}$*	CM
1996	3325	3952	1063	1197	1171
2002	2449	2241	675	832	1886
2018	2760	1683	503	832	2104
% Change	-17	-57	-53	-30	80

Chapter 4: Utah Visibility Analysis[92]

The rule adopted in 1999 defined "visibility impairment" as "any humanly perceptible change" (i.e., difference) "in visibility (light extinction, visual range, contract, or coloration) from that which would have existed under natural conditions."[93] The 1999 rule directed states to track visibility impairment on the 20% "most impaired days" and 20% "least impaired days" in order to determine progress towards natural visibility conditions.[94] This iteration of the rule did not define "most impaired days" or "least impaired days" or clearly indicate whether they were the days with the highest and lowest values for both natural and anthropogenic impairment or for anthropogenic impairment only. However, the preamble to the 1999 final rule stated that the least and most impaired days were to be selected as the monitored days with the lowest and highest actual deciview levels, respectively, which encompass both natural and anthropogenic contributions to reduced visibility.[95] In 2003, the EPA issued a guidance detailing the steps for selecting and calculating light extinction on the "worst" and "best" visibility days, which also indicated that it is preferable for states to determine the least and most impaired days based on monitoring data rather than determining and selecting the days with the highest and lowest anthropogenic impacts.[96] For the assessment purposes in the first planning period, the GCVTC considered the average of the days representing the 20% best visibility conditions to be the least impaired days.

The "worst" visibility days for some CIAs are impacted by natural emissions (e.g., wildfires and dust storms). These natural contributions to haze vary in magnitude and duration. WRAP used regional photochemical grid models to project visibility improvement between the 2002 baseline and the 2018 future year and to set RPGs for the RHR state implementation plans. Despite western states projecting large emission reductions from EGUs, mobile sources and smoke management programs, the results of the 2018 visibility RPGs indicated many western CIAs were projected to achieve less progress than the glidepath.

As a result, EPA modified the way in which certain days during each year are to be selected for purposes of tracking progress towards natural visibility conditions in order to focus attention on days when anthropogenic emissions impair visibility and away from days when wildfires and natural dust storms are the greatest contributors to visibility impairment.[97] These changes will

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[92] 40 CFR 51.308(F)(1)
[93] "64 Fed. Reg. 35714, 35764."
[94] "40 CFR 51.308(d)(2)(i)-(iv)."
[95] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[96] The EPA Guidance for Tracking Progress Under the Regional Haze Rule can be found at https://www.epa.gov/visibility/guidance-tracking-progress-under-regional-haze-rule
[97] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

provide the public and public officials with more meaningful information on how emission reduction contribute to a decline in anthropogenic visibility impairment by reasonably reducing the distorting effects of wildfires and natural dust storms on estimates of reasonable progress.

The EPA method defined a threshold for the episodic portion of natural haze for the carbonaceous species (organic mass carbon (OMC), elemental carbon (EC)) and crustal material (fine soil plus coarse mass), components that are indicators of wildfires and dust storms, respectively.[98] EPA recommended nominal thresholds for each episodic species' combinations as the minimums of the yearly 95th percentile for the 15-year period from 2000 to 2014. The daily fraction of species extinction values greater than the 95th percentile threshold are assigned to the natural episodic bin. Smaller, routine natural contributions from biogenic or geogenic emissions are assumed to be a constant fraction of the measured IMPROVE species concentrations on each day, with the fraction calculated as the ratio of a previously estimated annual average natural concentration[99] (Natural Conditions II, NC-II) divided by the non-episodic annual average IMPROVE concentrations measured for each species. The metric calculates the

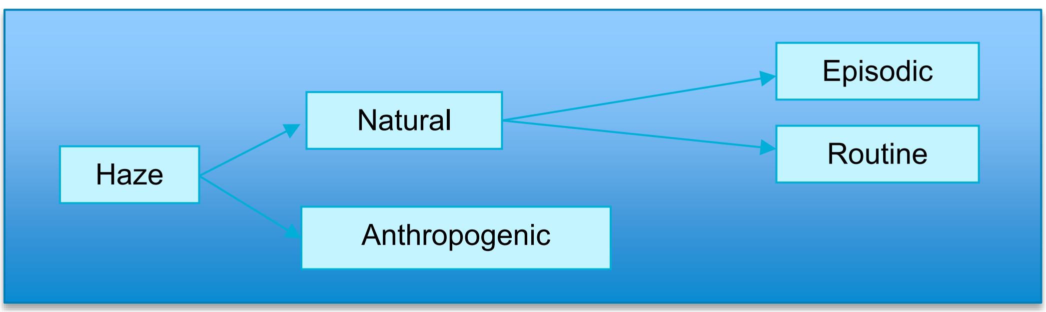

Figure 25: Light extinction for Utah Class I Areas: natural and anthropogenic sources

natural routine portion, such that its annual average (excluding episodic events) is equal to the site and species-specific NC-II concentrations.

Daily anthropogenic impairment is calculated as:

$$\Delta\ \mathbf{dv}_{\text{anthropogenic visibility impairment}} = \mathbf{dv}_{\text{total}} - \mathbf{dv}_{\text{natural}}$$

Daily anthropogenic impairment values are ranked from high to low impairment in order to select the 20% most impaired days (MIDs) each year. States must now determine the baseline (2000-2004) visibility condition for the 20% most anthropogenically impaired days. This approach differs from the previous round in which the 20% most impaired days were selected from days with the highest total impairment, not separating anthropogenic versus natural impairment. Once the most impaired days are selected, states must calculate the rate of visibility improvement over time that is required to reach natural conditions by 2064 for the 20% most impaired days. Using the metric described above for separating natural (episodic and routine)

[98] Figure 25 shows how haze is separated into natural and anthropogenic causes
[99] IMPROVE. 2007. Natural Haze Levels II: Application of the New IMPROVE Algorithm to Natural Species Concentrations Estimates. Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/gray-literature/ (accessed October 2021)

and anthropogenic, natural conditions are calculated as the average of the daily natural contributions on the 20% most impaired days, in the period 2000-2014. The figures below display the clearest and most impaired days calculated as described in EPA guidance. The line drawn from the baseline to the endpoint is termed the glidepath, or the “uniform rate of progress (URP),” and is calculated for each Class I area, and is used as a tracking metric for the path to natural conditions. The URP is calculated with the following formula:

$$URP = \frac{[(2000\text{–}2004\ visibility)20\%\ most\ impaired - (natural\ visibility)20\%\ most\ impaired]}{60}$$

The most impaired days are the 20% of days with the highest anthropogenic fraction of total haze. Tracking visibility progress on those days with highest impairment is intended to limit the influence of episodic wildfires and dust storms on the visibility trends.

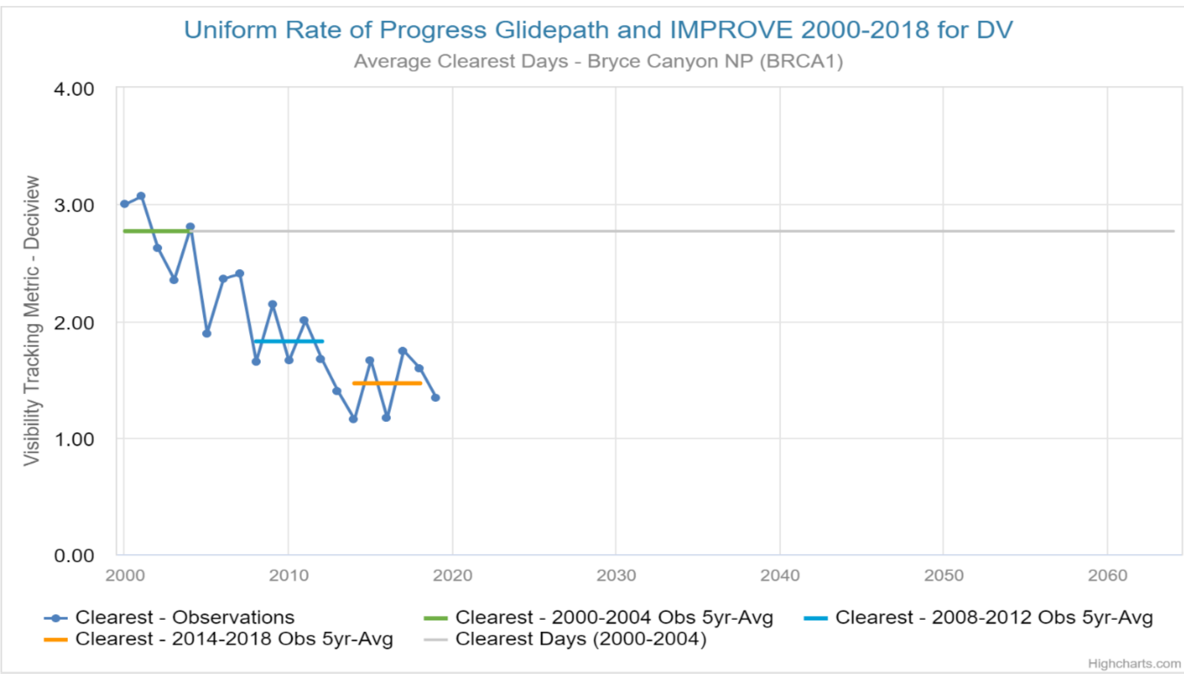

Figure 26: URP Glidepath for Clearest Days, Bryce Canyon NP

No changes were made from the previous implementation period in how the 20% clearest days are calculated. The 20% clearest days are calculated from the days with the lowest total impairment. As stated previously, the RHR requires states to demonstrate that there is no degradation in the 20% clearest days from the baseline period.[100]

[100] “64 Fed. Reg. 35714, 35764.”

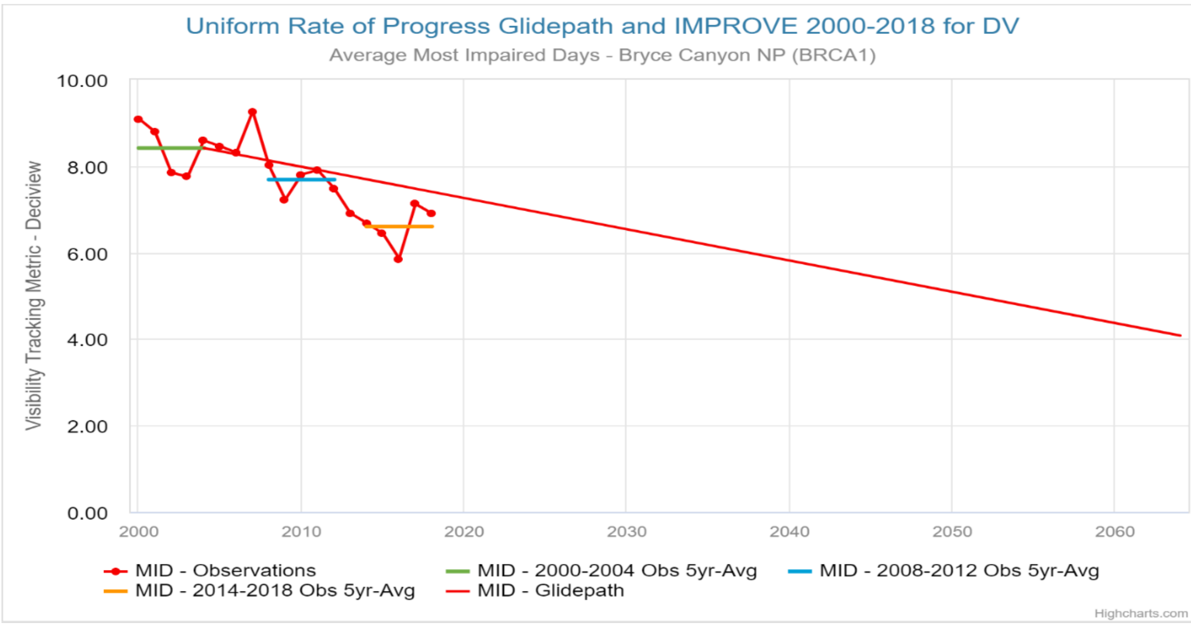

Figure 27: URP Glidepath for most impaired days, Bryce Canyon NP

4.A Baseline, Current Conditions and Natural Visibility Conditions

Section 51.308(f)(1) of the RHR requires Utah to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the uniform rate of progress (URP) for each of its five CIAs. According to the RHR, baseline period visibility conditions, current visibility conditions, natural conditions, and the URP should be expressed in deciviews and calculated based on total light extinction.[101] Baseline visibility conditions are based on available monitoring data of the most impaired and clearest days during the period of 2000 to 2004. Current visibility conditions are to be calculated based upon the most recent five years of data by calculating the average of the annual deciview index values for the most impaired days and clearest days in this period, and averaging these respective annual values. Natural visibility conditions are to be calculated by estimating the average deciview index on most impaired and clearest days under natural conditions. Calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.[102]

[101] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[102] Table 4 and Table 5 describe the IMPROVE site information for Utah's CIAs

Table 4: Representative IMPROVE Monitoring Sites

Class I Area Name	Representative IMPROVE Site	Site ID
Arches National Park	Canyonlands NP	CANY1
Bryce Canyon National Park	Bryce Canyon NP	BRCA1
Canyonlands National Park	Canyonlands NP	CANY1
Capitol Reef National Park	Capitol Reef NP	CAPI1
Zion National Park	Zion NP	ZICA1

Table 5: IMPROVE site information for CIAs

Site ID	Class I Area Name(s)	Latitude	Longitude	State	AQS Code
BRCA1	Bryce Canyon National Park	37.6184	-112.1736	UT	49-017-0101
CANY1	Arches National Park, Canyonlands National Park	38.4587	-109.821	UT	49-037-0101
CAPI1	Capitol Reef National Park	38.3022	-111.2926	UT	49-055-9000
ZICA1	Zion National Park	37.1983	-113.1507	UT	49-053-0130

4.A.1 Baseline (2000-2004) visibility for the most impaired and clearest days[103]

Baseline visibility conditions are based on the available IMPROVE monitoring data of the 20% most impaired and clearest days during the period of 2000 to 2004. Table 6 shows the baseline visibility calculated for clearest days and most impaired days for each of Utah's CIAs.

Table 6: Baseline Visibility for the 20% Most Impaired Days and 20% Clearest Days

Site ID	Class I Area Name(s)	Clearest Days (dv)	Most Impaired Days (dv)
BRCA1	Bryce Canyon National Park	2.77	8.42
CANY1	Arches National Park, Canyonlands National Park	3.75	8.79
CAPI1	Capitol Reef National Park	4.10	8.78
ZICA1	Zion National Park	4.48	10.40

4.A.2 Natural visibility for the most impaired and clearest days[104]

Natural visibility conditions are to be calculated by estimating the average deciview index on most impaired and clearest days under natural conditions. Table 7 summarizes the natural visibility values calculated for the clearest and most impaired days in each of Utah's CIAs.

[103] (40 CFR 51.308(f)(1)(i))

[104] (40 CFR 51.308(f)(1)(ii))

Table 7: Natural Visibility values for Utah CIAs

Site ID	Class I Area Name(s)	Clearest Days (dv)	Most Impaired Days (dv)
BRCA1	Bryce Canyon National Park	0.57	4.08
CANY1	Arches National Park, Canyonlands National Park	1.05	4.13
CAPI1	Capitol Reef National Park	1.28	4.00
ZICA1	Zion National Park	1.83	5.26

4.A.3 Current (2014-2018) visibility for the most impaired and clearest days[105]

Current visibility conditions are to be calculated based upon the most recent five years of data by calculating the average of the annual deciview index values for the most impaired days and clearest days in this period, and averaging these respective annual values. Table 8 below shows the current visibility values calculated for the clearest and most impaired days in each of Utah's CIAs.

Table 8: Current Visibility (2014-2018) conditions in Utah CIAs

Site ID	Class I Area Name(s)	Clearest Days (dv)	Most Impaired Days (dv)
BRCA1	Bryce Canyon National Park	1.46	6.60
CANY1	Arches National Park, Canyonlands National Park	2.20	6.76
CAPI1	Capitol Reef National Park	2.38	7.18
ZICA1	Zion National Park	3.86	8.75

[105] (40 CFR 51.308(f)(1)(iii))

4.A.4 Progress to date: most impaired and clearest days[106]

Actual progress towards the natural visibility conditions goal has been calculated in relation to the baseline period for each of Utah's CIAs. This is exhibited by the difference between the average visibility condition during the 5-year baseline, previous implementation period, and each subsequent 5-year period up to and including the current period. Table 9 displays the progress in Utah's CIAs comparing the baseline values for clearest and most impaired days with the first implementation period and 2014-2018 values.

Table 9: Progress to date for the most impaired and clearest days

Site ID	2000-2004 Baseline (dv)		2008-2012 Previous implementation period (dv)		2014-2018 Current (dv)	
	20% Clearest	20% Most Impaired	20% Clearest	20% Most Impaired	20% Clearest	20% Most Impaired
BRCA1	2.77	8.42	1.82	7.69	1.46	6.60
CANY1	3.75	8.79	2.93	8.12	2.20	6.76
CAPI1	4.10	8.78	2.53	8.16	2.38	7.18
ZICA1	4.48	10.40	4.22	9.17	3.86	8.75

4.A.5 Differences between current and natural for the most impaired and clearest days[107]

Table 10 compares the difference between the current deciview values for each CIA to the estimated natural visibility for the 20% most impaired days and clearest days.

Table 10: Current visibility compared to natural visibility

Site ID	2014-2018 Current (dv)		Natural Visibility (dv)		Difference (dv)	
	20% Clearest	20% Most Impaired	20% Clearest	20% Most Impaired	20% Clearest	20% Most Impaired
BRCA1	1.46	6.60	0.57	4.08	0.89	2.52
CANY1	2.20	6.76	1.05	4.13	1.15	2.63
CAPI1	2.38	7.18	1.28	4.00	1.1	3.18
ZICA1	3.86	8.75	1.83	5.26	2.03	3.49

[106] (40 CFR 51.308(f)(1)(iv))
[107] (40 CFR 51.308(f)(1)(v))

4.B Uniform Rate of Progress[108]

Utah analyzed and determined the uniform rate of progress (URP) over time for each of its five CIAs, starting at the baseline period of 2000-2004, that would be needed to attain the natural visibility condition on the 20% most anthropogenically impaired days by the year 2064. Table 11 shows the URP for each IMPROVE site.

Table 11: Uniform Rates of Progress

CIA IMPROVE Site	Baseline Conditions (Most Impaired Days) (dv)	2064 Natural Conditions (Most Impaired Days) (dv)	Years to Reach Natural Conditions	Uniform Rate of Progress (URP) (dv/year)
BRCA1	8.42	4.08	60	-0.072
CANY1	8.79	4.13	60	-0.078
CAPI1	8.78	4.00	60	-0.080
ZICA1	10.40	5.26	60	-0.086

Utah then used the URP to establish the level of visibility change needed from baseline conditions by 2028 as shown in Table 12. The 2028 URP level is used for comparison to WRAP photochemical modeling projections for 2028 shown in sections 6.A.10 and 8.C.

Table 12: Calculation of 2028 Uniform Rate of Progress Level

CIA IMPROVE Site	Baseline Conditions (Most Impaired Days) (dv)	Visibility Change by 2028 (URPX24 years) (dv)	2028 URP Level (dv)
BRCA1	8.42	-1.74	6.68
CANY1	8.79	-1.87	6.92
CAPI1	8.78	-1.91	6.87
ZICA1	10.40	-2.06	8.35

4.C Adjustments to URP: International impacts and/or prescribed fire[109]

EPA added a provision in the 2019 guidance that allows EPA to approve adjustments to the URP to reflect the impacts of international and wildland prescribed fire sources of visibility impairment if an adjustment has been developed through scientifically valid data and methods. These adjustments would be developed and applied separately, although they would both be accomplished by adding an estimate of the impact of the relevant source type or types to the value of the natural visibility condition for the 20% most anthropogenically impaired days, for the purposes of calculating the URP.[110] The wildland prescribed fires that are eligible under the

[108] (40 CFR 51.308(f)(1)(vi))
[109] (40 CFR 51.308(f)(1)(vi)(B)(1) and (2))
[110] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

RHR to be included in this adjustment are those conducted with the objective to establish, restore, and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve endangered or threatened species during which appropriate basic smoke management practices were applied.[111]

Consistent with the methods evaluated in the EPA Technical Support Document[112], WRAP calculated the international and wildland prescribed fire glidepath adjustments for Utah using 2028OTBa2 source apportionment modeling results normalized to the IMPROVE monitoring data and added to EPA estimated natural conditions.[113]

Modeling done by both EPA and WRAP shows that Utah is significantly impacted by international and wildland prescribed fire emissions (as shown by Figures 28-31). Further detail on emission source apportionment can be found in Chapter 5: Utah Sources of Visibility Impairment.

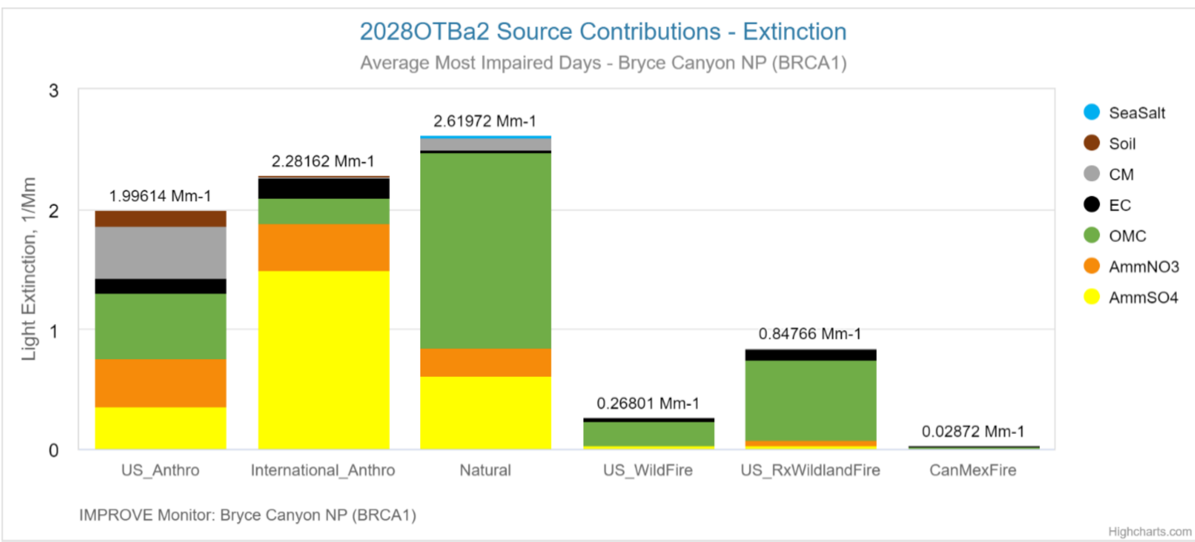

Figure 28: Projected Source Contributions to Light Extinction in Bryce Canyon NP

[111] "64 Fed. Reg. 35714, 35764."
[112] Technical Support Document (TSD) Revised Recommendations for Visibility Progress Tracking Metrics for the Regional Haze Program https://www.epa.gov/sites/default/files/2016-07/documents/technical_support_document_for_draft_guidance_on_regional_haze.pdf

[113] WRAP Technical Support System for Regional Haze Planning: Modeling Methods, Results, and References
https://views.cira.colostate.edu/tssv2/Docs/WRAP_TSS_modeling_reference_final_20210930.pdf

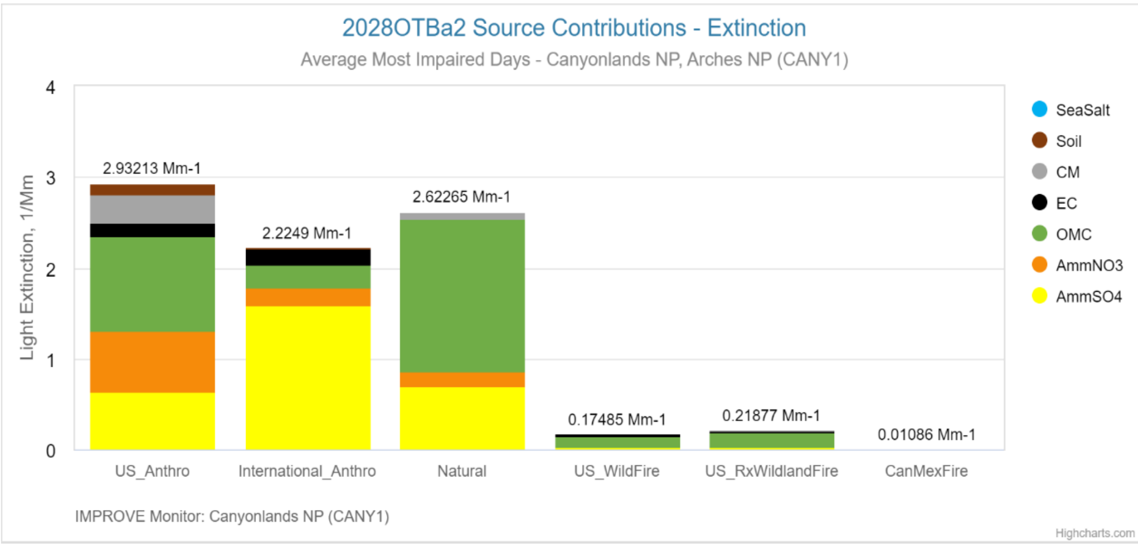

Figure 29: Projected Source Contributions to Light Extinction in Canyonlands and Arches NP

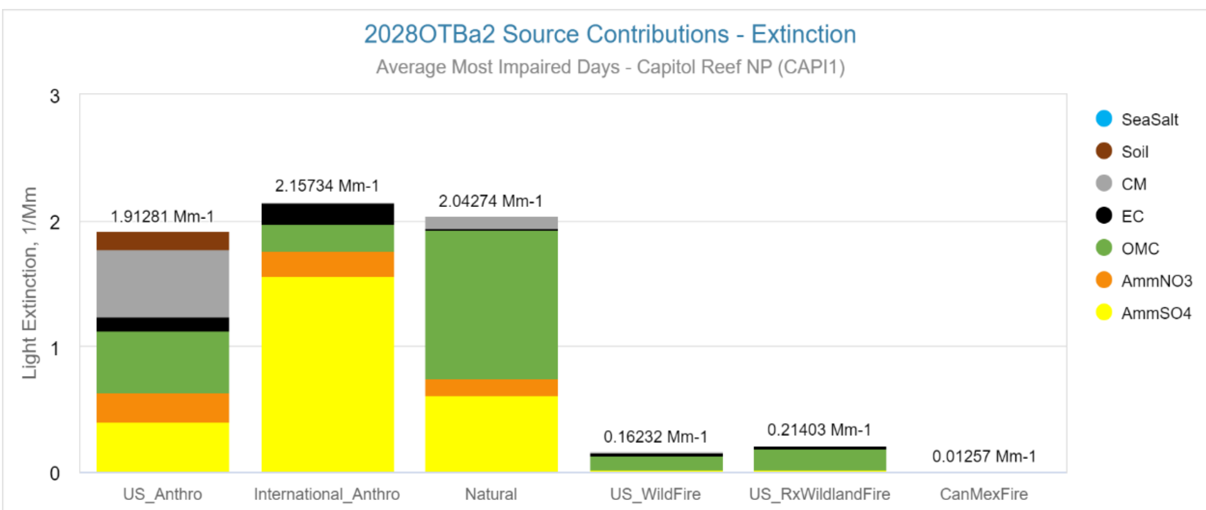

Figure 30: Projected Source Contributions to Light Extinction in Capitol Reef NP

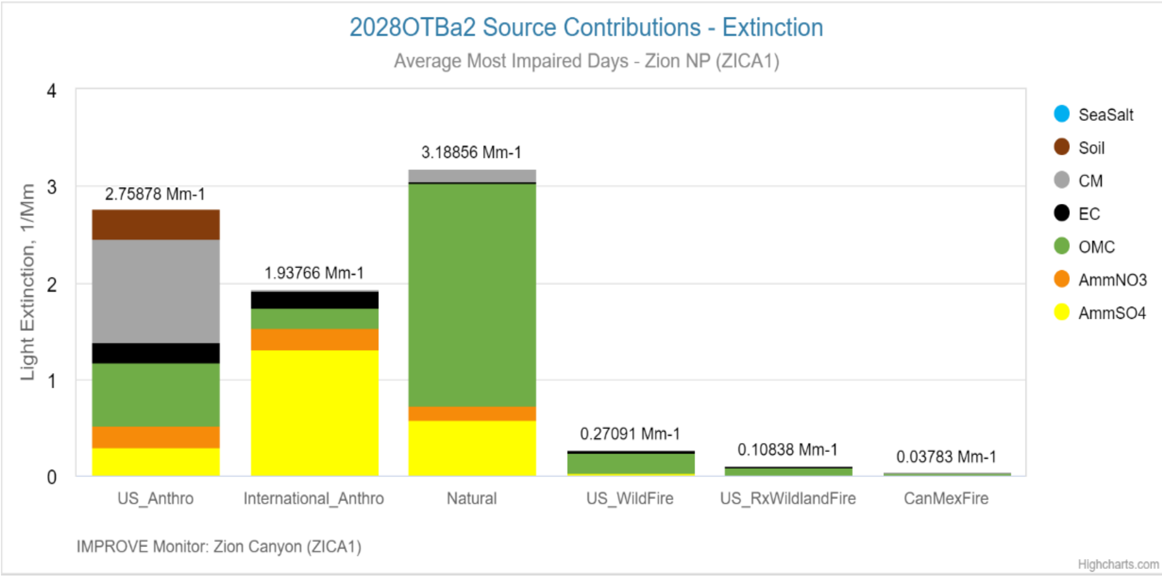

Figure 31: Projected Source Contributions to Light Extinction in Zion NP

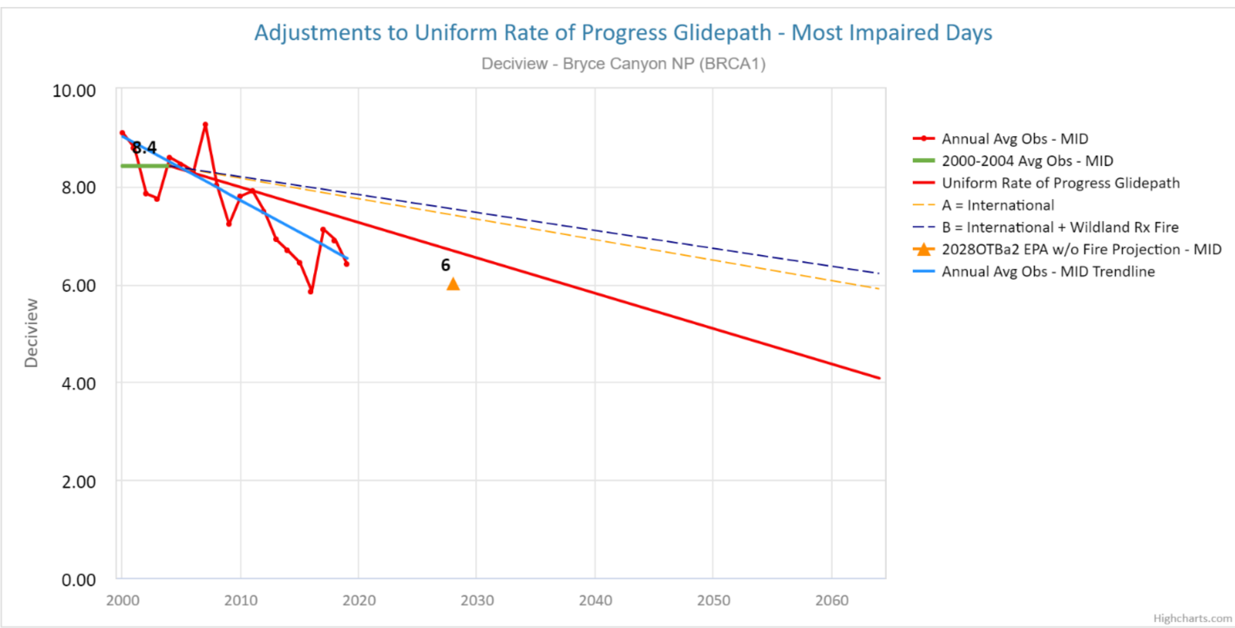

Figure 32: Example URP Glidepath for Bryce Canyon National Park Showing Adjustment Options

Figure 32 shows an example of Bryce Canyon's URP glidepath with the international and wildland prescribed fire adjustments. It should be noted that the prescribed fire adjustments for Utah's CIAs are small relative to those in other states. The international source adjustments, on the other hand, can be sizable. While the international and wildland prescribed fire adjustments are available for Utah's CIA glidepaths, UDAQ is choosing to remain conservative for the purposes of this implementation period by not using them. However, this choice does not preclude the use of glidepath adjustments in future planning periods, since international and wildland prescribed fire emissions do impact Utah CIAs and are largely beyond the control of individual states and since prescribed fires are seen to be an increasingly important tool for land managers in the future.

Chapter 5: Utah Sources of Visibility Impairment

5.A Natural Sources of Impairment

Natural impairment sources include any non-anthropogenically caused visibility-reducing emissions and are often seasonally attributed to natural events such as rain, sea mists, windblown dust, wildfire, volcanic activity, and biogenic emissions. Natural sources of impairment are often caused by seasonal conditions and lead to high concentrations of visibility-impairing emissions that are short-term. Natural contributions to impairment are categorized into the "episodic" and "routine" types. Episodic contributions, such as large wildfires or dust storms, occur infrequently and vary yearly in number and size. Routine contributions include biogenic sources, sea salt, and incorporate the site-specific value for Rayleigh scattering, a term which refers to the scattering of light off of particles in the air. These contributions occur often and are more consistent on a yearly basis.

5.B Anthropogenic Sources of Impairment

Anthropogenic impairment sources include any visibility-decreasing emissions directly related to human-caused activities. These activities include industrial processes (utilities, smelters, refineries, etc.), mobile sources (cars, trucks, trains, etc.) and area sources (residential wood burning, prescribed burning on wild and agricultural lands, wind-blown dust from disturbed soils, etc.). Anthropogenic sources of emissions include those originating within Utah as well as neighboring states, Mexico, Canada, and maritime shipping emissions from across the Pacific Ocean. While Utah can consult with regional states about their anthropogenic emission contributions to impairment in Utah's CIAs, those international contributions cannot be controlled at the state level. Table 13 details the data sources used by WRAP for determining anthropogenic source emissions contributions.

Table 13: Data sources for WRAP emissions sectors[114]

Source Sector	2014v2	RepBase2	2028OTBa2
California All Sectors 12WUS2	CARB-2014v2	CARB-2014v2	CARB-2028
WRAP Fossil EGU w/ CEM	WRAP-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Fossil EGU w/o CEM	EPA-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Non-Fossil EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-WRAP EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
O&G WRAP O&G States	WRAP-2014v2	WRAP-RB-O&G [2]	WRAP-2028-O&G [2]
O&G WRAP Other States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
O&G non-WRAP States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
WRAP Non-EGU Point	WRAP-2014v2	WRAP-2014v2 [4]	WRAP-2014v2 [4]
Non-WRAP non-EGU Point	EPA-2014v2	EPA-2016v1	EPA-2016v1
On-Road Mobile 12WUS2	WRAP-2014v2	WRAP-2014v2	WRAP-2028-Mobile [5]
On-Road Mobile 36US	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-Road 12WUS2	EPA-2014v2	EPA-2016v1	WRAP-2028-Mobile [5]
Non-Road non-WRAP 36US	EPA-2014v2	EPA-2016v1 [6]	EPA-2028v1 [6]

[114] This table's data comes from the 2021 WRAP Technical Support System Emissions and Modeling Report and References document.

Other (Non-Point) 12WUS2	EPA-2014v2	EPA-2014v2 [7]	EPA-2014v2 [7]
Other (Non-Point) 36US	EPA-2014v2	EPA-2016v1	EPA-2016v1
Can/Mex/Offshore 12WUS2	EPA-2014v2	EPA-2016v1	EPA-2016v1
Fires (WF, Rx, Ag)	WRAP-2014-Fires	WRAP-RB-Fires [8]	WRAP-RB-Fires [8]
Natural (Bio, etc.)	WRAP-2014v2	WRAP-2014v2	WRAP-2014v2
Boundary Conditions (BCs)	WRAP-2014-GEOS	WRAP-2014-GEOS	WRAP-2014-GEOS

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

5.C Overview of Emission Inventory System - TSS

The WRAP 2014v2 inventory was based on the National Emissions Inventory (NEI) and updates provided by states through their Emissions and Modeling Protocol subcommittee. Specific data sources for each emissions sector are detailed below:

The CAMx Particle Source Apportionment tool (PSAT) is a photochemical model that tracks gaseous and particle air emissions from sources through atmospheric dispersion, photochemical reactions, and transport to receptors where IMPROVE monitors are located. These PSAT runs include aerosol concentrations of:

- AmmNO_3
- AmmSO_4
- Primary Organic Mass from Carbon (OMC)
- Primary Elemental Carbon (EC)
- Primary Fine Soil
- Primary Coarse Mass
- Sea salt
- Secondary Organic Aerosols
    - Anthropogenic (SOAA)
    - Biogenic (SOAB)

These particles are direct products of primary gaseous and particle emissions and secondary aerosol formation. Secondary organic aerosols (SOA) tracers are not used in these PSAT runs, rather SOAs at the receptor are assigned to anthropogenic (SOAA) or biogenic (SOAB) contributions based on the chemical signatures (e.g., isoprene is assigned as biogenic in origin; benzene is assigned as anthropogenic in origin).

WRAP modeled values for six source categories and 15 component source groups[115]:

- U.S. Anthropogenic (USAnthro)
  - U.S. anthropogenic (AntUS)
  - U.S. agricultural fire (AgfireUS)
  - Secondary Organic Aerosol-Anthropogenic (SOAA)
  - Commercial Marine Vessels (CMVUS)
  - U.S. anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-US)
- U.S. Wildfire (WFUS)
- U.S. Wildland Prescribed fire (RxUS)
- Canadian and Mexican fires (OthFr)
- Natural
  - Natural (Nat)
  - Secondary Organic Aerosol -Biogenic (SOAB)
  - Natural contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-Nat)
- International Anthropogenic (IntlAnthro)
  - International Anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-Int)
  - Canadian Anthropogenic (AntCAN)
  - Mexican Anthropogenic (AntMEX)
  - Commercial Marine vessels – International (beyond 200km from U.S. coast) (CMV_nonUS)

Summaries of Utah's emissions data are located in Table 15 to Table 20.

5.D Wildland Prescribed Fires

Most forest ecosystems in the West have a general pattern in which fires naturally occur, otherwise called a fire regime. These regimes serve the purpose of helping a forest get rid of excess wood fuel and cause opportunities for regrowth and regeneration. Many forest ecosystems in the West depend on fire to create their optimal conditions. As human populations increase in the West, the Wildland-Urban Interface (WUI) has led to fire suppression which impedes natural fire regimes for the safety of residential areas. This causes an increase in fuel (burnable wood) in the forests of Utah that increases their chances of unintentionally catching fire. Further contributing to the dangers of uncontrolled fire is the increase in climate change every year. To better control the location and degree at which forest fires occur, fire can be prescribed for an area under certain weather conditions and with the appropriate permits. Utilizing prescribed fires and returning fire to an ecosystem in a controlled manner helps restore its health and reduce potentially catastrophic wildfires. Healthy ecosystems with restored natural fire regimes are more resistant to severe fire, disease, and insect infestations. The United States Forest Service (USFS) and other land management agencies in Utah closely monitor

[115] Information on the TSS source apportionment data is located at http://views.cira.colostate.edu/tssv2/Reports2/Modeling/Src-App-DB-Avg-Bext-By-Source.aspx

local precipitation, wind, fuel, moisture, and other elements to determine the best conditions to carry out prescribed burning.

The State of Utah and the USFS have developed mutual commitments to advance the strategy of "Shared Stewardship" in Utah. In August 2018, the Forest Service released a document outlining a new strategy for land management called "Toward Shared Stewardship Across Landscapes: An Outcome-Based Investment Strategy." This strategy responds to the growing challenges faced by land managers including catastrophic wildfires. Of particular concern are longer fire seasons and the increasing size and severity of wildfires, along with the expanding risk to communities, water sources, wildlife habitat, air quality, and the safety of firefighters. Through Shared Stewardship, the State and Forest Service can work together and set landscape-scale priorities, implement projects at the appropriate scale, co-manage risks, share resources, and learn from each other while building long-term capacity to live with wildfire. Due to these initiatives, more frequent wildfires in the West, and thus increasing importance of prescribed fires, Utah does not consider reducing prescribed fires as a reasonable method to reduce visibility impairment.

5.E Utah Emissions

Federal visibility regulations[116] require a statewide emissions inventory of pollutants anticipated to contribute to visibility impairment in Utah's CIAs. WRAP inventoried pollutants in Utah including SO_2, NO_x, VOCs, $PM_{2.5}$, PM_{10}, and NH_3. The WRAP 2014v2 inventory was based on the 2014v2 National Emissions Inventory (NEI) as well as updates provided by western states (including Utah). RepBase2, the representative baseline emissions scenario, updated the 2014v2 inventory originally used to account for changes and variations in emissions from 2014 to 2018.[117] This version also accounted for duplicate records found and revised some EGU, non-EGU point, oil, and gas emissions. The 2028 On the Books Inventory (2028OTBa2) projection follows the methods presented by the EPA in their 2019 Technical Support Document. WRAP states updated projections for all anthropogenic source sectors. Oil and gas area emissions were also updated by Ramboll, Inc. and the WRAP Oil and Gas Workgroup and separated into Tribal and non-Tribal mineral ownership. Table 14 contains data compiled by WRAP with information on the status of EGU retirements in Utah that were used in the RepBase2 and 2028OTBa2 inventories.

Table 14: Status of Utah EGU Retirements in RepBase2 and 2028OTBa2 Inventories

Facility Name	Unit ID	In-Service Year	Retirement Year	Notes	Operator	Unit Type
Intermountain	1SGA	1986	2025	Announced retirement	Intermountain Power Service Corporation	Dry bottom wall-fired boiler
Intermountain	2SGA	1987	2025	Announced retirement	Intermountain Power Service Corporation	Dry bottom wall-fired boiler

[116] 40 C.F.R. § 51.308(d)(4)(v).
[117] UDAQ notes that these projections include emission not under state jurisdiction (i.e. Tribal)

Facility Name	Unit ID	In-Service Year	Retirement Year	Notes	Operator	Unit Type
Bonanza	1-Jan	1986	2030	Coal consumption cap	Deseret Generation & Transmission	Dry bottom wall-fired boiler
Hunter	1	1978	2042	PAC IRP; Round 1 RH FIP in Litigation	PacifiCorp Energy Generation	Tangentially-fired
Hunter	2	1980	2042	PAC IRP; Round 1 RH FIP in Litigation	PacifiCorp Energy Generation	Tangentially-fired
Hunter	3	1983	2042	PAC IRP	PacifiCorp Energy Generation	Dry bottom wall-fired boiler
Huntington	1	1977	2036	PAC IRP; Round 1 RH FIP in Litigation	PacifiCorp Energy Generation	Tangentially-fired
Huntington	2	1974	2036	PAC IRP; Round 1 RH FIP in Litigation	PacifiCorp Energy Generation	Tangentially-fired

The resulting inventories were then used by WRAP to model future visibility in Utah's CIAs.[118]

State and federal law require Utah to conduct a statewide emissions inventory program every three years. This inventory accounts for point, area, and mobile sources and accounts for the following criteria pollutants:

- Ammonia (NH_3)
- Carbon Monoxide (CO)
- Lead and Lead Compounds
- Nitrogen Oxides (NO)
- Particulate Matter (PM_{10} and $PM_{2.5}$)
- Sulfur Oxides (SO_2)
- Volatile Organic Compounds (VOCs)

The following tables contain Utah's projected emissions inventories by species resulting from the RepBase2 and 2018OTBa2 modeling projections.

[118] The complete methodology used to develop the WRAP emissions inventory can be found in "WRAP Technical Support System for Regional Haze Planning: Emissions and Modeling Methods, Results, and References" released on August 19, 2021.

Table 15: Utah SO_2 Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2

Utah – Statewide SO_2 Emissions (TPY)				
Type	**Source Category**	**2014v2 Actual**	**Representative Baseline 2**	**2028 OTB a2**
Anthropogenic	Electric Generating Units (EGU)	24,011	11,357	9,866
Anthropogenic	Oil and Gas – Point	664	545	570
Anthropogenic	Industrial and Non-EGU Point	2,400	2,402	2,402
Anthropogenic	Oil and Gas – Non-point	41	41	31
Anthropogenic	Residential Wood Combustion	24	24	24
Anthropogenic	Fugitive dust	0	0	0
Anthropogenic	Agriculture	0	0	0
Anthropogenic	Remaining Non-point	61	61	61
Anthropogenic	On-Road Mobile	275	275	185
Anthropogenic	Non-road Mobile	25	16	13
Anthropogenic	Rail	3	3	3
Anthropogenic	Commercial Marine	0	0	0
Anthropogenic	Agricultural Fire	5	5	5
Anthropogenic	Wildland Prescribed Fire	320	524	524
	Total Anthropogenic	**27,829**	**15,253**	**13,684**
Natural	Wildfire	375	1,295	1,295
Natural	Biogenic	0	0	0
	Total Natural	**375**	**1,295**	**1,295**
	Grand Total	**28,204**	**16,548**	**14,979**

The largest source of SO_2 emissions is fossil fuel combustion (mainly coal) at power plants and other industrial facilities. In Utah, the largest source of SO_2 emissions are EGUs. Smaller sources include metal extraction, mobile vehicles, and wood burning. Wildfires are the second largest source of SO_2 emissions in both the RepBase and 2028 scenarios. SO_2 emissions that lead to high concentrations of SO_2 in the air generally also lead to the formation of other sulfur oxides (SO_x). SO_x can react with other compounds in the atmosphere to form small particles. These particles contribute to PM pollution. Ammonium sulfate particles can have a great impact on visibility due to their greater light scattering effects. According to the 2028OTBa2 modeling, SO_2 emissions are projected to decline to 14,979 tons per year in 2028.

Table 16: Utah NO_x Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2

Utah – Statewide NO_x Emissions (TPY)				
Type	**Source**	**2014v2**	**Representative**	**2028 OTB a2**

Utah – Statewide NO_x Emissions (TPY)				
	Category	**Actual**	**Baseline 2**	
Anthropogenic	Electric Generating Units (EGU)	54,497	31,882	23,848
Anthropogenic	Oil and Gas – Point	14,636	14,589	9,140
Anthropogenic	Industrial and Non-EGU Point	13,086	13,107	13,107
Anthropogenic	Oil and Gas – Non-point	1,811	1,806	1,428
Anthropogenic	Residential Wood Combustion	189	189	189
Anthropogenic	Fugitive dust	0	0	0
Anthropogenic	Agriculture	0	0	0
Anthropogenic	Remaining Non-point	4,846	4,846	4,846
Anthropogenic	On-Road Mobile	74,643	74,643	25,539
Anthropogenic	Non-road Mobile	9,669	7,029	4,741
Anthropogenic	Rail	5,646	5,646	4,164
Anthropogenic	Commercial Marine	1	0	0
Anthropogenic	Agricultural Fire	19	19	19
Anthropogenic	Wildland Prescribed Fire	596	572	572
	Total Anthropogenic	**179,639**	**154,328**	**87,593**
Natural	Wildfire	704	2,063	2,063
Natural	Biogenic	12,602	12,602	12,602
	Total Natural	**13,306**	**14,665**	**14,665**
	Grand Total	**192,945**	**168,993**	**102,258**

NO_x is a group of highly reactive gases formed in high-temperature combustion processes. This group includes NO_2, nitrous acid, and nitric acid. NO_2 emissions are primarily caused by fuel combustion from cars, trucks, buses, power plants, and off-road equipment. These substances are toxic by themselves and can react to form ozone or PM_{10} in the form of nitrates. Large nitrate particles have a greater light-scattering effect than large sulfate particles or dust particles. Most NO_x emissions in Utah are from EGUs. NO_x emissions are projected to decline to 102,258 tons per year, according to the 2028OTBa2 modeling.

Table 17: Utah VOC Emission Inventory – RebBase2 (2014-2018) and 2028OTBa2

Utah - Statewide VOC Emissions (TPY)				
Type	**Source Category**	**2014v2 Actual**	**Representative Baseline 2**	**2028 OTB a2**
Anthropogenic	Electric Generating Units (EGU)	391	285	276
Anthropogenic	Oil and Gas - Point	111,225	110,906	71,207
Anthropogenic	Industrial and Non-EGU Point	3,146	3,152	3,152
Anthropogenic	Oil and Gas - Non-point	37,069	35,252	21,513
Anthropogenic	Residential Wood Combustion	1,589	1,589	1,589
Anthropogenic	Fugitive dust	0	0	0
Anthropogenic	Agriculture	2,120	2,120	2,120

Utah - Statewide VOC Emissions (TPY)				
Anthropogenic	Remaining Non-point	29,913	29,913	29,913
Anthropogenic	On-Road Mobile	28,356	28,356	11,589
Anthropogenic	Non-road Mobile	17,694	8,966	6,314
Anthropogenic	Rail	287	287	179
Anthropogenic	Commercial Marine	0	0	0
Anthropogenic	Agricultural Fire	31	31	31
Anthropogenic	Wildland Prescribed Fire	8,675	23,415	23,415
	Total Anthropogenic	**240,496**	**244,272**	**171,298**
Natural	Wildfire	10,062	54,614	54,614
Natural	Biogenic	717,742	717,742	717,742
	Total Natural	**727,804**	**772,356**	**772,356**
	Grand Total	**968,300**	**1,016,628**	**943,654**

VOCs are volatile organic compounds that have high vapor pressure at room temperature. Many VOCs are human-made compounds that are used and produced in the manufacturing of paints, pharmaceuticals, and refrigerants. Companies in Utah must report all reactive VOC emissions (including fugitive emissions). Different VOCs have differing levels of reactivity that convert them to ozone. Therefore, changes in their emissions have limited effects on local or regional ozone pollution. VOCs also play a role in the formation of secondary particulates that can impact regional haze. The largest source of VOC emissions in Utah is oil and gas point sources. VOC emissions are expected to decline to 943,654 tons per year according to the 2028OTBa2 projections.

Table 18: Utah $PM_{2.5}$ Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2

Utah - Statewide $PM_{2.5}$ Emissions (TPY)				
Type	**Source Category**	**2014v2 Actual**	**Representative Baseline 2**	**2028 OTB a2**
Anthropogenic	Electric Generating Units (EGU)	2,799	2,195	1,310
Anthropogenic	Oil and Gas - Point	631	621	476
Anthropogenic	Industrial and Non-EGU Point	2,618	2,620	2,620
Anthropogenic	Oil and Gas - Non-point	81	81	61
Anthropogenic	Residential Wood Combustion	1,403	1,403	1,403
Anthropogenic	Fugitive dust	12,177	12,177	12,177
Anthropogenic	Agriculture	0	0	0
Anthropogenic	Remaining Non-point	1,181	1,181	1,181
Anthropogenic	On-Road Mobile	2,726	2,726	1,081
Anthropogenic	Non-road Mobile	1,103	706	447
Anthropogenic	Rail	165	165	108
Anthropogenic	Commercial Marine	0	0	0
Anthropogenic	Agricultural Fire	83	83	83

Anthropogenic	Wildland Prescribed Fire	3,580	7,092	7,092
	Total Anthropogenic	**28,547**	**31,050**	**28,039**
Natural	Wildfire	4,161	17,381	17,381
Natural	Biogenic	0	0	0
	Total Natural	**4,161**	**17,381**	**17,381**
	Grand Total	**32,708**	**48,431**	**45,420**

$PM_{2.5}$ particulates are fine, inhalable particles or droplets with a diameter of 2.5 microns or smaller. Within two years after the EPA revises NAAQS for criteria pollutants, it must designate areas according to their attainment status. These designations are based on the most recent three years of monitoring data, state recommendations, and other technical information. If an area is not meeting the standard, Utah must write a $PM_{2.5}$ SIP that includes necessary control measures to ensure future attainment. The sector with the largest contribution of $PM_{2.5}$ emissions in Utah is fugitive dust. $PM_{2.5}$ emissions are expected to decline somewhat according to the 2028OTBa2 modeling.

Table 19: Utah PM_{10} Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2

Utah - Statewide PM_{10} Emissions (TPY)				
Type	**Source Category**	**2014v2 Actual**	**Representative Baseline 2**	**2028 OTB a2**
Anthropogenic	Electric Generating Units (EGU)	3,671	2,534	1,607
Anthropogenic	Oil and Gas - Point	632	621	476
Anthropogenic	Industrial and Non-EGU Point	5,385	5,387	5,387
Anthropogenic	Oil and Gas - Non-point	81	81	61
Anthropogenic	Residential Wood Combustion	1,410	1,410	1,410
Anthropogenic	Fugitive dust	95,505	95,505	95,505
Anthropogenic	Agriculture	0	0	0
Anthropogenic	Remaining Non-point	1,317	1,317	1,317
Anthropogenic	On-Road Mobile	4,547	4,547	3,550
Anthropogenic	Non-road Mobile	1,165	745	477
Anthropogenic	Rail	179	179	111
Anthropogenic	Commercial Marine	0	0	0
Anthropogenic	Agricultural Fire	119	119	119
Anthropogenic	Wildland Prescribed Fire	4,224	8,097	8,097
	Total Anthropogenic	**118,235**	**120,542**	**118,117**
Natural	Wildfire	4,910	20,318	20,318
Natural	Biogenic	0	0	0
	Total Natural	**4,910**	**20,318**	**20,318**
	Grand Total	**123,145**	**140,860**	**138,435**

PM_{10} is inhalable particulate matter that is 10 microns or smaller in diameter. Sources of PM_{10} include:

- Vehicles
- Wood-burning
- Wildfires or open burns
- Industry
- Dust from construction sites, landfills, gravels pits, agriculture, and open lands

The NAAQS for PM specifies the maximum amount of PM present in outdoor air. PM concentration is measured in micrograms per cubic meter, or µg/m^3. For PM_{10}, most high values tend to occur during wintertime inversions. In the summertime, high wind events can also lead to unusually high PM_{10} values. According to the 2028OTBa2 projections, PM_{10} emissions are expected to decrease to 138,435 tons per year in 2028. This is lower than the representative baseline from 2014 to 2017, but higher than the recalculated 2014 emissions.

Table 20: Utah NH_3 Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2

Utah - Statewide NH_3 Emissions				
Type	Source Category	2014v2 Actual	Representative Baseline 2	2028 OTB a2
Anthropogenic	Electric Generating Units (EGU)	273	262	261
Anthropogenic	Oil and Gas - Point	0	0	0
Anthropogenic	Industrial and Non-EGU Point	400	400	400
Anthropogenic	Oil and Gas - Non-point	0	0	0
Anthropogenic	Residential Wood Combustion	63	63	63
Anthropogenic	Fugitive dust	0	0	0
Anthropogenic	Agriculture	12,982	12,982	12,982
Anthropogenic	Remaining Non-point	5,012	5,012	5,012
Anthropogenic	On-Road Mobile	1,025	1,025	1,039
Anthropogenic	Non-road Mobile	17	14	17
Anthropogenic	Rail	3	3	3
Anthropogenic	Commercial Marine	0	0	0
Anthropogenic	Agricultural Fire	70	70	70
Anthropogenic	Wildland Prescribed Fire	678	1,164	1,164
	Total Anthropogenic	**20,523**	**20,995**	**21,011**
Natural	Wildfire	787	2,702	2,702
Natural	Biogenic	0	0	0
	Total Natural	**787**	**2,702**	**2,702**
	Grand Total	**21,310**	**23,697**	**23,713**

NH_3 plays a role in light extinction since it is involved in the formation of ammonium nitrate and ammonium sulfate. The various industries that emit NH_3 include:

- Fertilizer manufacturing
- Fossil fuel combustion
- Livestock management
- Refrigeration methods

Currently, there is limited federal regulation of NH_3 emissions, although the CAA provides federal authority to regulate this pollutant. NH_3 emissions levels are consistent in each of the three WRAP projections for 2014, 2014-2017, and 2028.

Chapter 6: Long-Term Strategy for Second Planning Period[119]

6.A LTS Requirements [120]

The Long-Term Strategy requirements under Subsections 51.308(d)(3) and (f)(2) include the following:

- Submit an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment.
- Consult with other states to develop coordinated emission management strategies for CIAs outside Utah where Utah emissions cause or contribute to visibility impairment, or for CIAs in Utah where emissions from other states cause or contribute to visibility impairment.
- Enforceable emissions limitations, compliance schedules, and other measures necessary to achieve the reasonable progress goals established by Utah for its CIAs.
- Document the technical basis on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each CIA it affects.
- Identify all anthropogenic sources of visibility impairing emissions (major and minor stationary sources, mobile sources, and area sources).
- Consider the following factors when developing the LTS:
    - Emission reductions due to ongoing air pollution control programs, including measures to address Reasonably Attributable Visibility Impairment (RAVI);
    - Measures to mitigate the impacts of construction activities;
    - Emission limitations and schedules for compliance to achieve the reasonable progress goal;
    - Source retirement and replacement schedules;
    - Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
    - Enforceability of emission limitations and control measures; and
    - The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

Sections 6.A.1 through 6.A.8 detail how Utah addressed the above LTS factors.

[119] 40 CFR 51.308(f)(2)
[120] 40 CFR 51.308(d)(3) and (f)(2)

6.A.1 States reasonably anticipated to contribute to visibility impairment in the Utah CIAs[121]

Bryce Canyon National Park

In Bryce Canyon National Park, California contributes the highest portion of U.S. anthropogenic ammonium nitrate-caused light extinction on most impaired days at 35%, followed by Utah at 23%. California also contributes the highest amount of U.S. anthropogenic ammonium sulfate light extinction in Bryce Canyon at 19% followed by non-WRAP states at 14%, Utah at 14%, Arizona at 12%, Wyoming at 12%, and New Mexico at 11%.

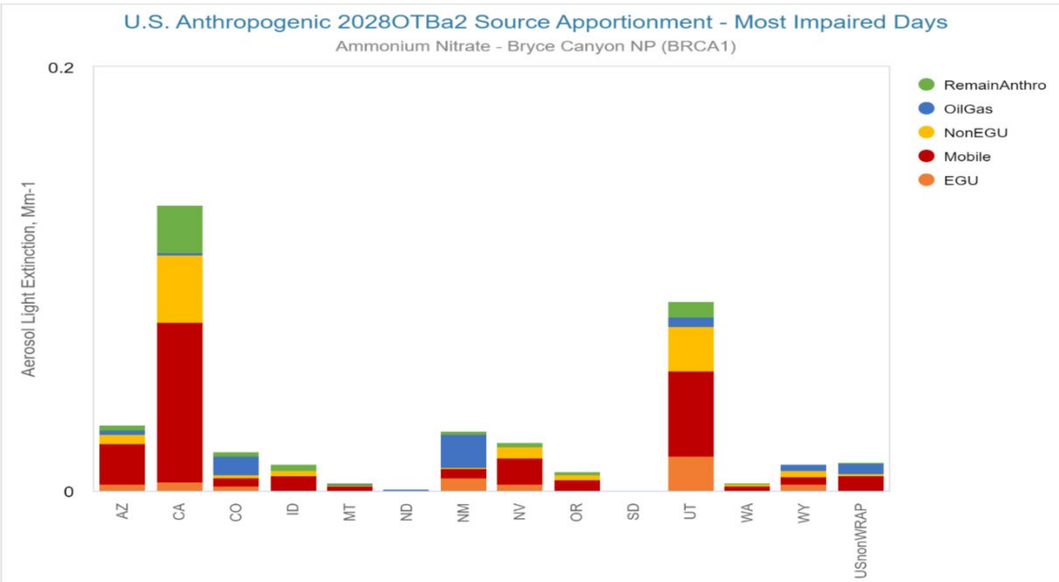

Figure 33: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Bryce Canyon National Park

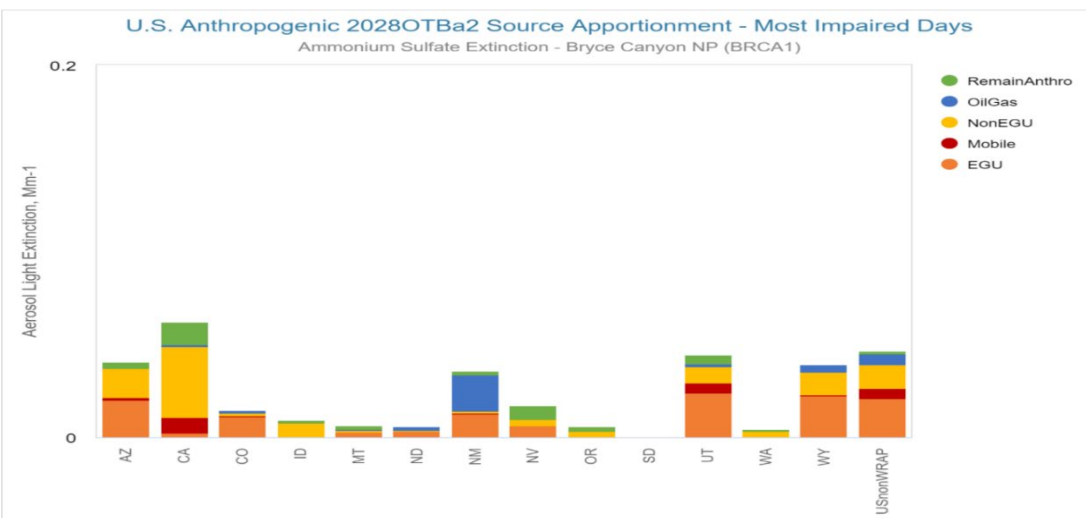

Figure 34: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Bryce Canyon National Park

[121] 40 CFR 51.308 (f)(2)(ii)

Canyonlands and Arches National Park

In Canyonlands and Arches National Park, Utah contributes the largest portion of U.S. ammonium nitrate light extinction (60%) followed by Colorado (14%). Utah also contributes the most U.S. ammonium sulfate light extinction (40%) on the park's most impaired days followed by New Mexico (13%) and non-WRAP US states (12%).

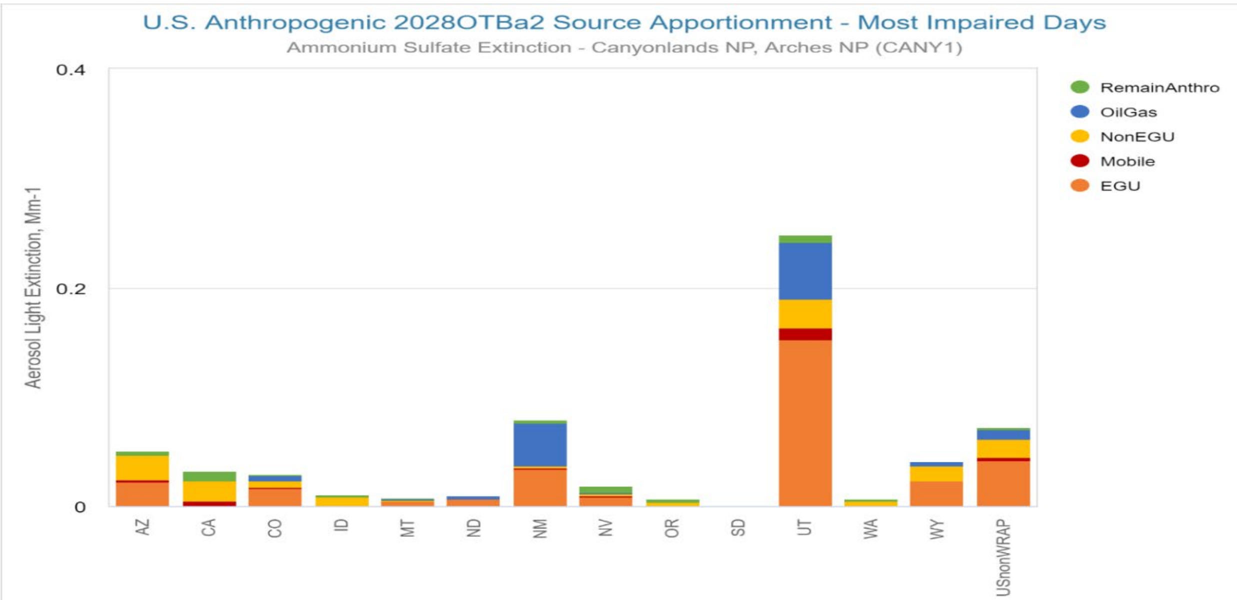

Figure 35: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Canyonlands and Arches National Park

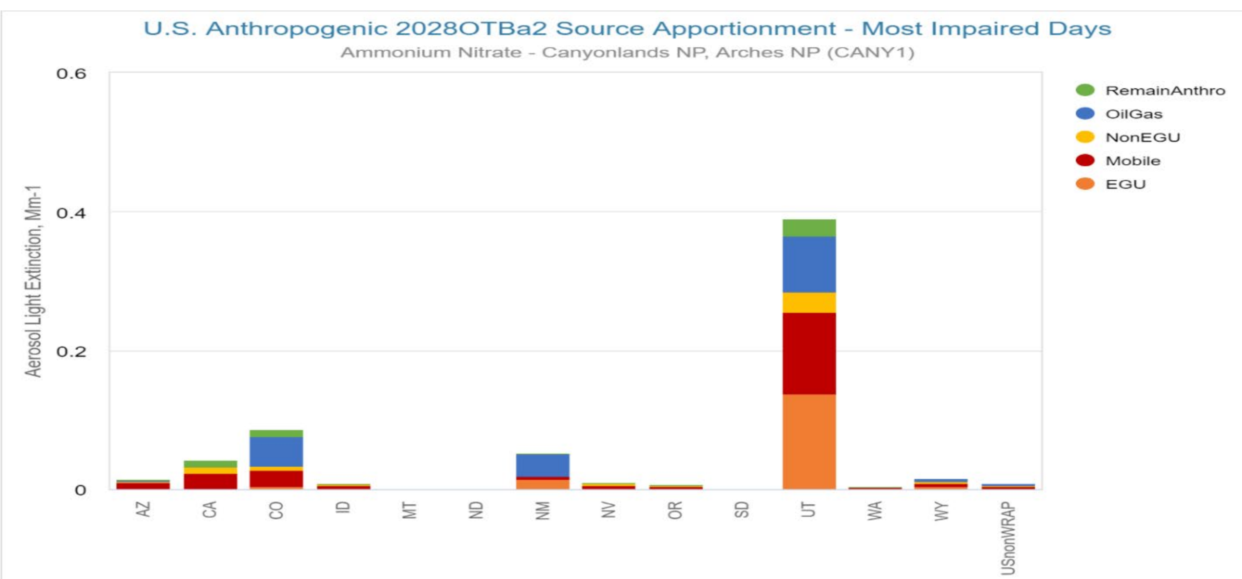

Figure 36: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Canyonlands and Arches National Park

Capitol Reef National Park

Utah contributes the highest portion of U.S. anthropogenic ammonium nitrate light extinction on Capitol Reef's most impaired days at 35%. California contributes the second-highest amount at 21%. Utah also contributes the highest portion of U.S. anthropogenic ammonium sulfate light extinction at 20%, closely followed by non-WRAP states (15%), California (13%), and Wyoming (13%).

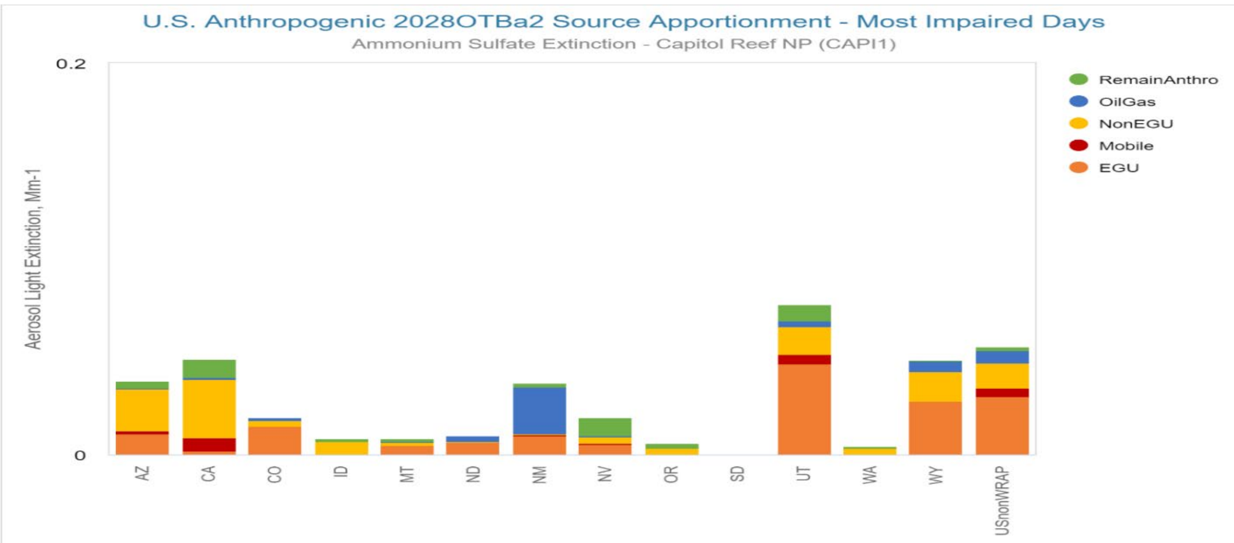

Figure 37: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Capitol Reef National Park

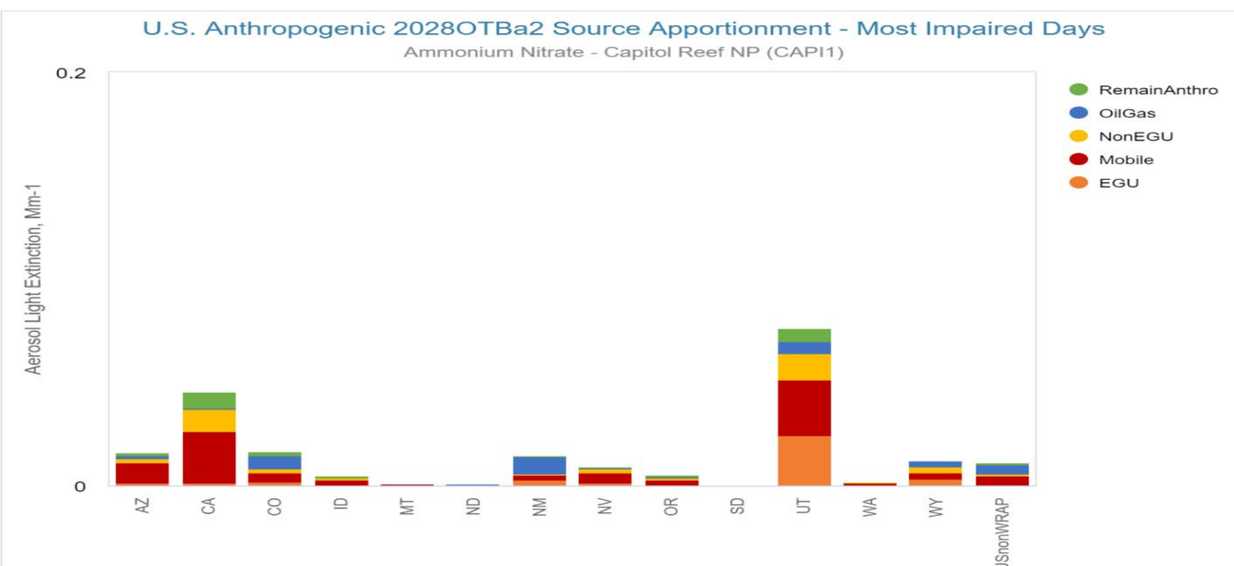

Figure 38: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Capitol Reef National Park

Zion National Park

For Zion National Park's most impaired days, California contributes the highest portion of U.S. anthropogenic ammonium nitrate light extinction (49%) with mobile emissions comprising the majority of their impact (27%). California also contributes to the majority of U.S. anthropogenic ammonium sulfate light extinction (37%), most of which are from non-EGU sources (23%).

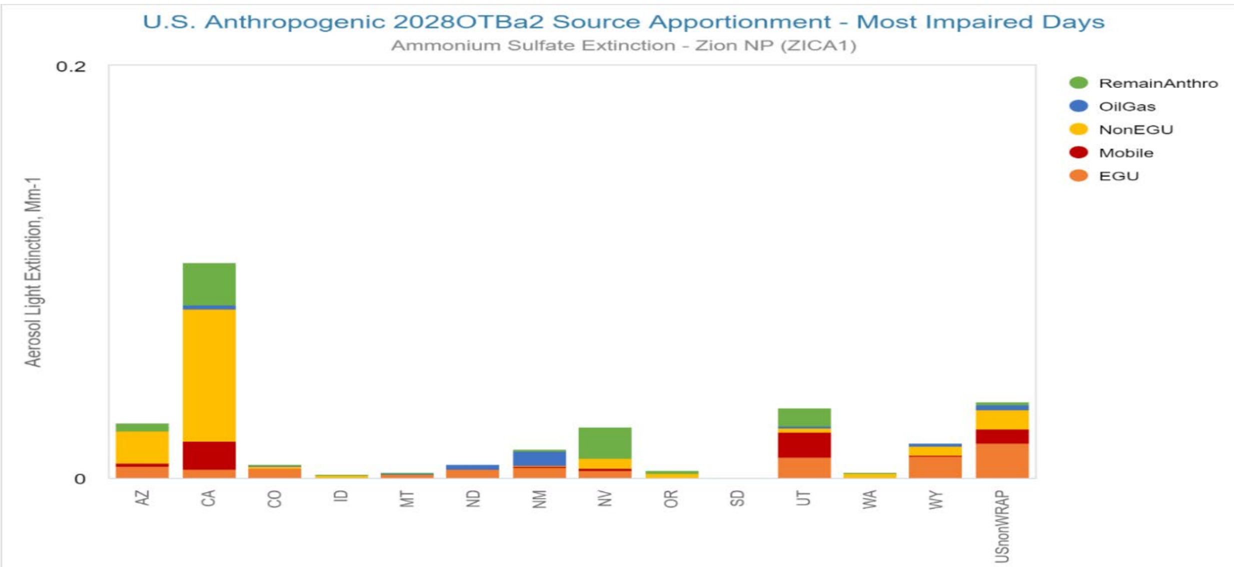

Figure 39: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Zion National Park

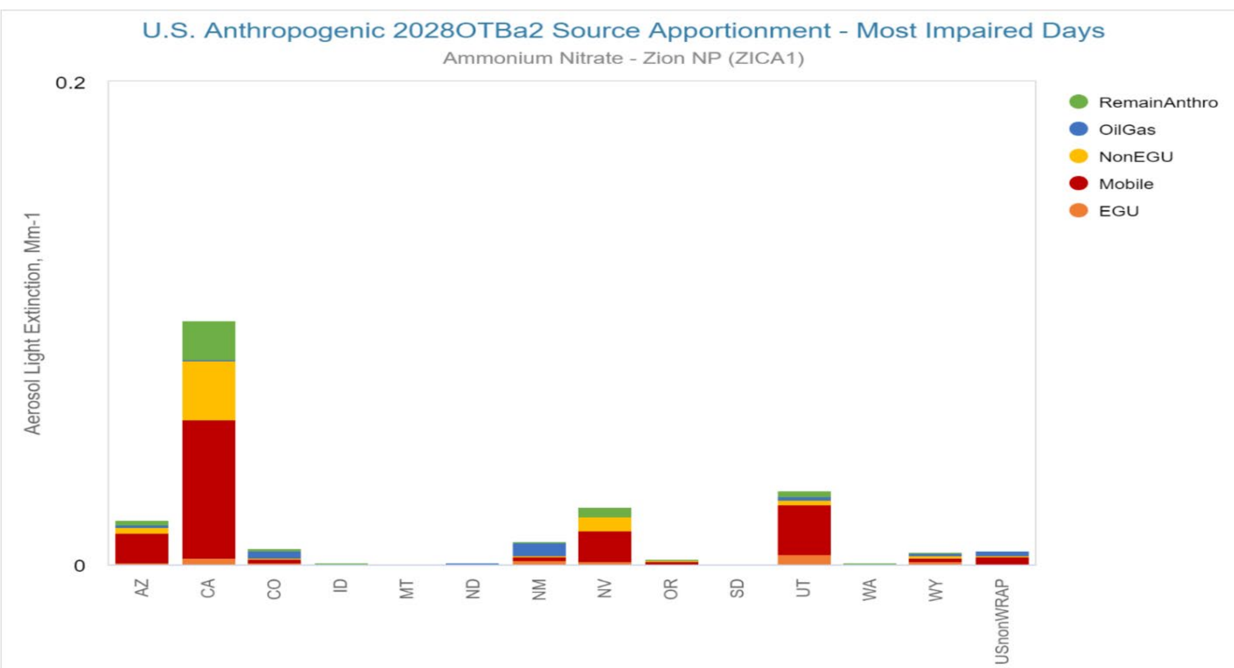

Figure 40: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Zion National Park

6.A.2 Utah sources identified by downwind states that are reasonably anticipated to impact CIAs[122]

Utah has analyzed the WRAP photochemical modeling for OTB 2028 and found that emissions from Utah can impact visibility at CIAs in other states. Table 21 and Table 22 below summarize Utah's percent contribution to total U.S. anthropogenic nitrate and sulfate light extinction at CIAs in neighboring states. As can be seen, Utah's highest nitrate impacts occur in Colorado, Idaho, and Wyoming CIAs and mostly stem from mobile source emissions. Utah's highest sulfate impacts also occur in Colorado, Idaho, and Wyoming (namely at MOZI1, WHRI1, CRMO1, and BRID1) and predominantly stem from EGU emissions and some non-EGU emissions in the case of CRMO1. It should be noted that the WRAP source apportionment results for Utah EGUs include impacts from the Bonanza power plant, which is located in Indian Country and which is not, therefore, a source regulated by UDAQ. A review of the weighted emissions potential (WEP) values for sulfate at the latter CIAs identified one Utah EGU, Kennecott Power Plant, with a top-ten sulfate WEP value for BRID1 (rank 2, 7.4% of total WEP). However, this facility was officially closed in 2020. The facilities with the two highest ranking non-EGU WEP sulfate values at CRMO1 were the Tesoro (now Marathon) refinery (rank 6, 6.8% of total WEP) and the Kennecott Smelter and Refinery (rank 10, 2.2% of total WEP), both of which recently underwent BACT analysis for the Salt Lake $PM_{2.5}$ serious area SIP and are well-controlled for SO_2.

As one might expect, when Utah anthropogenic impacts are compared to total nitrate and sulfate light extinction at the same CIAs, Utah's shares drop markedly, as shown in Table 23 and Table 24, respectively. And nitrate and sulfate are only two of several contributors to total visibility impairment. As such, Utah's shares of nitrate and sulfate impacts should be considered in this broader context. That said, the aforementioned source apportionment results were not used to screen out any sources from a requirement to conduct a four-factor analysis. Rather, UDAQ relied upon a preliminary Q/d analysis to identify sources with a Q/d of >=6. UDAQ then conducted a secondary screening to review the initial pool of Q/d-qualifying sources to account for factors such as recent emissions controls required by other air quality programs, facility closures, federal preemptions on state controls, etc. Finally, UDAQ reviewed WEP results for nitrate and sulfate to ensure that the remaining Q/d pool reasonably captured sources with impacts at Utah and non-Utah CIAs. This screening analysis is detailed in section 7.A.

Table 21: Utah Share of U.S. Anthropogenic Nitrate Impacts on Neighboring State CIAs

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
AZ	BALD1	0.19%	0.22%	0.10%	0.02%	0.03%	0.55%
AZ	CHIR1	0.76%	0.68%	0.29%	0.19%	0.13%	2.05%
AZ	GRCA2	0.64%	0.63%	0.13%	0.22%	0.09%	1.71%
AZ	IKBA1	0.21%	0.29%	0.10%	0.05%	0.07%	0.73%
AZ	PEFO1	2.89%	1.95%	0.75%	0.57%	0.56%	6.73%
AZ	SAGU1	0.35%	0.32%	0.10%	0.08%	0.07%	0.93%
AZ	SIAN1	0.19%	0.19%	0.11%	0.02%	0.03%	0.53%

[122] 40 CFR 51.308 (f)(2)(ii)(A)

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
AZ	SYCA_RHTS	1.12%	1.45%	0.57%	0.23%	0.26%	3.62%
AZ	TONT1	0.22%	0.30%	0.09%	0.05%	0.07%	0.74%
CO	GRSA1	2.39%	1.35%	0.44%	0.59%	0.32%	5.08%
CO	MEVE1	4.33%	2.76%	0.81%	0.91%	0.68%	9.49%
CO	MOZI1	4.14%	7.23%	3.00%	3.00%	1.44%	18.81%
CO	ROMO1	1.95%	3.53%	1.47%	1.27%	0.72%	8.94%
CO	WEMI1	2.43%	2.20%	0.72%	0.99%	0.25%	6.59%
CO	WHRI1	5.14%	6.75%	2.23%	2.64%	0.98%	17.74%
ID	CRMO1	0.62%	6.88%	3.42%	0.03%	2.02%	12.97%
ID	SAWT1	0.05%	0.38%	0.22%	0.01%	0.09%	0.74%
ID	SULA1	0.09%	0.96%	0.45%	0.01%	0.13%	1.63%
NM	BAND1	0.58%	0.43%	0.14%	0.14%	0.08%	1.37%
NM	BOAP1	0.50%	0.47%	0.19%	0.12%	0.12%	1.41%
NM	GICL1	0.27%	0.38%	0.15%	0.07%	0.06%	0.93%
NM	GUMO1	0.17%	0.27%	0.09%	0.06%	0.02%	0.60%
NM	SACR1	0.06%	0.06%	0.02%	0.02%	0.01%	0.17%
NM	SAPE1	0.84%	0.60%	0.24%	0.24%	0.14%	2.05%
NM	WHIT1	0.12%	0.14%	0.05%	0.04%	0.03%	0.38%
NM	WHPE1	0.96%	0.84%	0.29%	0.23%	0.16%	2.48%
NV	JARB1	0.43%	1.32%	0.54%	0.10%	0.23%	2.63%
WY	BRID1	2.98%	12.91%	6.56%	1.53%	2.41%	26.39%
WY	NOAB1	0.49%	3.11%	1.60%	0.07%	0.72%	5.98%
WY	YELL2	0.63%	5.90%	2.94%	0.07%	1.43%	10.97%

Table 22: Utah Share of U.S. Anthropogenic Sulfate Impacts on Neighboring State CIAs

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
AZ	BALD1	0.60%	0.03%	0.23%	0.02%	0.02%	0.91%
AZ	CHIR1	1.26%	0.04%	0.33%	0.08%	0.03%	1.74%
AZ	GRCA2	2.18%	0.08%	0.19%	0.28%	0.08%	2.81%
AZ	IKBA1	1.29%	0.07%	0.29%	0.10%	0.06%	1.81%
AZ	PEFO1	2.30%	0.11%	0.51%	0.14%	0.07%	3.12%
AZ	SAGU1	1.36%	0.06%	0.34%	0.06%	0.04%	1.86%
AZ	SIAN1	0.62%	0.03%	0.18%	0.03%	0.03%	0.89%
AZ	SYCA_RHTS	4.21%	0.22%	1.45%	0.09%	0.15%	6.13%
AZ	TONT1	1.31%	0.06%	0.33%	0.09%	0.04%	1.84%
CO	GRSA1	4.85%	0.09%	0.38%	0.52%	0.07%	5.91%
CO	MEVE1	7.97%	0.17%	0.84%	1.57%	0.14%	10.69%
CO	MOZI1	10.25%	0.27%	1.48%	0.67%	0.18%	12.85%
CO	ROMO1	5.89%	0.28%	2.12%	0.49%	0.17%	8.96%
CO	WEMI1	6.79%	0.19%	0.96%	1.41%	0.14%	9.49%
CO	WHRI1	22.85%	0.45%	1.91%	2.12%	0.30%	27.62%

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
ID	CRMO1	4.17%	0.48%	4.08%	0.01%	0.35%	9.10%
ID	SAWT1	1.23%	0.06%	0.82%	0.01%	0.04%	2.15%
ID	SULA1	0.79%	0.11%	0.70%	0.01%	0.08%	1.70%
NM	BAND1	1.25%	0.04%	0.18%	0.22%	0.02%	1.70%
NM	BOAP1	0.68%	0.03%	0.14%	0.04%	0.02%	0.91%
NM	GICL1	0.89%	0.04%	0.26%	0.04%	0.03%	1.25%
NM	GUMO1	0.49%	0.02%	0.12%	0.03%	0.01%	0.66%
NM	SACR1	0.21%	0.01%	0.04%	0.01%	0.00%	0.27%
NM	SAPE1	2.07%	0.06%	0.31%	0.25%	0.05%	2.74%
NM	WHIT1	0.29%	0.01%	0.06%	0.02%	0.01%	0.38%
NM	WHPE1	1.55%	0.05%	0.28%	0.13%	0.03%	2.04%
NV	JARB1	2.05%	0.12%	0.85%	0.03%	0.07%	3.13%
WY	BRID1	12.26%	0.63%	5.98%	0.30%	0.42%	19.59%
WY	NOAB1	4.01%	0.15%	1.12%	0.17%	0.12%	5.57%
WY	YELL2	5.29%	0.35%	3.22%	0.05%	0.24%	9.15%

Table 23: Utah Share of Total Nitrate Impacts on Neighboring State CIAs

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
AZ	BALD1	0.06%	0.07%	0.03%	0.01%	0.01%	0.17%
AZ	CHIR1	0.17%	0.15%	0.06%	0.04%	0.03%	0.45%
AZ	GRCA2	0.07%	0.07%	0.01%	0.03%	0.01%	0.20%
AZ	IKBA1	0.12%	0.16%	0.06%	0.03%	0.04%	0.41%
AZ	PEFO1	1.34%	0.90%	0.35%	0.26%	0.26%	3.11%
AZ	SAGU1	0.18%	0.17%	0.05%	0.04%	0.04%	0.48%
AZ	SIAN1	0.10%	0.09%	0.06%	0.01%	0.01%	0.27%
AZ	SYCA_RHTS	0.38%	0.50%	0.19%	0.08%	0.09%	1.24%
AZ	TONT1	0.13%	0.18%	0.06%	0.03%	0.04%	0.44%
CO	GRSA1	1.19%	0.68%	0.22%	0.29%	0.16%	2.54%
CO	MEVE1	2.38%	1.52%	0.45%	0.50%	0.37%	5.21%
CO	MOZI1	1.77%	3.09%	1.28%	1.28%	0.61%	8.03%
CO	ROMO1	1.19%	2.16%	0.90%	0.77%	0.44%	5.45%
CO	WEMI1	0.94%	0.85%	0.28%	0.38%	0.10%	2.54%
CO	WHRI1	1.81%	2.39%	0.79%	0.93%	0.35%	6.27%
ID	CRMO1	0.26%	2.94%	1.46%	0.01%	0.86%	5.54%
ID	SAWT1	0.01%	0.08%	0.05%	0.00%	0.02%	0.16%
ID	SULA1	0.02%	0.18%	0.08%	0.00%	0.02%	0.31%
NM	BAND1	0.32%	0.24%	0.08%	0.08%	0.05%	0.75%
NM	BOAP1	0.24%	0.22%	0.09%	0.06%	0.06%	0.67%
NM	GICL1	0.01%	0.01%	0.00%	0.00%	0.00%	0.03%
NM	GUMO1	0.06%	0.09%	0.03%	0.02%	0.01%	0.20%

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
NM	SACR1	0.04%	0.04%	0.01%	0.01%	0.01%	0.12%
NM	SAPE1	0.44%	0.31%	0.13%	0.12%	0.07%	1.07%
NM	WHIT1	0.05%	0.06%	0.02%	0.02%	0.01%	0.17%
NM	WHPE1	0.42%	0.37%	0.13%	0.10%	0.07%	1.09%
NV	JARB1	0.11%	0.33%	0.13%	0.03%	0.06%	0.65%
WY	BRID1	0.97%	4.20%	2.13%	0.50%	0.78%	8.57%
WY	NOAB1	0.08%	0.49%	0.25%	0.01%	0.11%	0.95%
WY	YELL2	0.18%	1.69%	0.84%	0.02%	0.41%	3.14%

Table 24: Utah Share of Total Sulfate Impacts on Neighboring State CIAs

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
AZ	BALD1	0.06%	0.00%	0.02%	0.00%	0.00%	0.10%
AZ	CHIR1	0.13%	0.00%	0.03%	0.01%	0.00%	0.17%
AZ	GRCA2	0.93%	0.03%	0.08%	0.12%	0.03%	1.19%
AZ	IKBA1	0.14%	0.01%	0.03%	0.01%	0.01%	0.20%
AZ	PEFO1	0.46%	0.02%	0.10%	0.03%	0.01%	0.63%
AZ	SAGU1	0.20%	0.01%	0.05%	0.01%	0.01%	0.27%
AZ	SIAN1	0.06%	0.00%	0.02%	0.00%	0.00%	0.09%
AZ	SYCA_RHTS	0.50%	0.03%	0.17%	0.01%	0.02%	0.72%
AZ	TONT1	0.15%	0.01%	0.04%	0.01%	0.00%	0.21%
CO	GRSA1	1.31%	0.02%	0.10%	0.14%	0.02%	1.60%
CO	MEVE1	1.98%	0.04%	0.21%	0.39%	0.03%	2.66%
CO	MOZI1	2.68%	0.07%	0.39%	0.18%	0.05%	3.36%
CO	ROMO1	1.64%	0.08%	0.59%	0.14%	0.05%	2.50%
CO	WEMI1	1.45%	0.04%	0.20%	0.30%	0.03%	2.02%
CO	WHRI1	4.16%	0.08%	0.35%	0.39%	0.05%	5.02%
ID	CRMO1	0.46%	0.05%	0.45%	0.00%	0.04%	1.01%
ID	SAWT1	0.08%	0.00%	0.05%	0.00%	0.00%	0.13%
ID	SULA1	0.05%	0.01%	0.05%	0.00%	0.01%	0.11%
NM	BAND1	0.41%	0.01%	0.06%	0.07%	0.01%	0.55%
NM	BOAP1	0.19%	0.01%	0.04%	0.01%	0.00%	0.25%
NM	GICL1	0.12%	0.01%	0.03%	0.00%	0.00%	0.17%
NM	GUMO1	0.11%	0.00%	0.03%	0.01%	0.00%	0.15%
NM	SACR1	0.06%	0.00%	0.01%	0.00%	0.00%	0.08%
NM	SAPE1	0.54%	0.01%	0.08%	0.07%	0.01%	0.71%
NM	WHIT1	0.07%	0.00%	0.01%	0.00%	0.00%	0.10%
NM	WHPE1	0.44%	0.01%	0.08%	0.04%	0.01%	0.58%
NV	JARB1	0.13%	0.01%	0.05%	0.00%	0.00%	0.20%
WY	BRID1	2.01%	0.10%	0.98%	0.05%	0.07%	3.21%
WY	NOAB1	0.35%	0.01%	0.10%	0.02%	0.01%	0.49%

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
WY	YELL2	0.68%	0.05%	0.41%	0.01%	0.03%	1.17%

6.A.3 Technical Basis of Reasonable Progress Goals

Please refer to sections 4.A.4 and 4.A.5 to view visibility progress to date and natural baseline comparisons for Utah's CIAs as well as section 6.A.10 to review UDAQ's Long-Term Strategy along with its technical basis.

6.A.4 Identify Anthropogenic Sources

Please refer to sections 5.C and 5.E for Utah's detailed emissions inventory by sector. Please refer to sections 7.A and 7.A.1 for Utah's source screening processes and Q/d analysis for determining which sources have the highest potential impact on Utah's CIAs.

6.A.5 Emissions Reductions Due to Ongoing Pollution Control Programs[123]

RAVI

RAVI refers to a process to identify and control visibility impairment that is caused by the emissions of air pollutants from one, or a small number of sources directly impacting a CIA. The three primary steps in this process are:[124]

- FLM certification of impairment
- State identification of existing sources causing or contributing to the impairment
- BART analysis to determine what controls, if any, are required on any existing source that meets BART criteria and has been identified as contributing to impairment

In the case that a FLM certifies impairment for any of Utah's CIAs, RAVI[125] will be addressed by the state through the following actions:

- Submittal of an initial RAVI LTS along with periodic revisions every three years
- Submittal of an LTS revision within three years of an FLM certification of impairment
- Consultation with FLMs
- Submittal of a report to the EPA and public on Utah's progress towards the national goal

UDAQ consulted with NPS who confirmed that none of Utah's CIAs have been certified as impaired by any FLMs.

National Ambient Air Quality Standards

The CAA requires the EPA to set NAAQS for pollutants considered harmful to public health and the environment. The CAA establishes two types of air quality standards: primary and

[123] 51.308(d)(3) and (f)(2)
[124] The Recommendations for Making Attribution Determinations in the Context of Reasonably Attributable BART can be found at:
http://www.westar.org/RA%20BART/final%20RA%20BART%20Report.pdf
[125] 40 CFR 51.302

secondary. Primary standards are set to protect public health, including the health of sensitive populations such as asthmatics, children, and the elderly. Secondary standards are set to protect public welfare, including protection from decreased visibility and damage to animals, crops, vegetation, and buildings.

The EPA has established health-based NAAQS for the six criteria pollutants including CO, NO_2, O_3, PM, SO_2, and lead. The EPA establishes the primary health standards after considering both the concentration level and the duration of exposure that can cause adverse health effects. Pollutant concentrations that exceed the NAAQS are considered unhealthy for some portion of the population. At concentrations between 1.0 and 1.5 times the standard, while the general public is not expected to be adversely affected by the pollutant, the most sensitive portion of the population may be. However, at levels above 1.5 times the standard, even healthy people may see adverse effects. The UDAQ monitors these criteria pollutants, as well as meteorological conditions and several non-criteria pollutants for special studies at various monitoring sites throughout the state.

The CAA has three different designations for areas based on whether they meet the NAAQS for each pollutant. Areas in compliance with the NAAQS are designated as attainment areas. Areas where there is no monitoring data showing compliance or noncompliance with the NAAQS are designated as unclassifiable areas. Areas that are not in compliance with the NAAQS are designated as nonattainment areas. A maintenance area is an attainment area that was once designated as nonattainment for one of the NAAQS and has since been demonstrated as attaining and continuing to attain that standard for a period of a minimum of 10 years. Most of the State of Utah has been designated as either Attainment or Unclassifiable for all the NAAQS.

Utah has never been out of compliance with any NO_2 standard, and has not exceeded the lead standard since the 1970s. Three cities in Utah (Salt Lake City, Ogden, and Provo) were at one time designated as nonattainment areas for carbon monoxide. Due primarily to improvements in motor vehicle technology, Utah has complied with the carbon monoxide standards since 1994. Salt Lake City, Ogden, and Provo were successfully redesignated to attainment status in 1999, 2001, and 2006, respectively.

Ozone (O_3)

In October of 2015, the EPA strengthened the ozone NAAQS from 75 ppb to 70 ppb, based on a three-year average of the annual 4th highest daily eight-hour average concentration. The standard was reviewed again in 2020 and the EPA chose to retain the standard at 70 ppb. Ozone monitors operated by the UDAQ along the Wasatch Front show exceedances of the current standard in Weber, Davis, and Salt Lake counties. There were also exceedances in Uinta County and Duchesne County during the winter. In 2016, the Governor recommended that portions of the Wasatch Front and Uinta Basin be designated non-attainment and that the rest of the State be designated attainment/unclassifiable. The current status of attainment for ozone in the Uintah basin is marginal non-attainment.

The unique wintertime ozone issue in the Uinta Basin is caused by oil and gas extraction. UDAQ is working on rule amendments and potentially new rules for the oil and gas industry to stay in compliance with the ozone NAAQS.

PM_{10}

The EPA established the 24-hour NAAQS for PM_{10} in July 1987 as 150 µg/m3. The standard is met when the probability of exceeding the standard is no greater than once per year for a three-year averaging period. Salt Lake County and Utah County had been designated nonattainment for PM_{10} shortly after the standard was promulgated. Ogden City was also designated as a nonattainment area due to one year of high concentrations (1992) but was determined to be attaining the standard in January 2013. State Implementation Plans (SIP) were written and promulgated in 1991 and included control strategies that resulted in the marked decrease in PM_{10} concentrations observed in the early 1990s. Ogden City, and Salt Lake and Utah Counties were officially designated as attainment for PM_{10} effective March 27, 2020. These three former nonattainment areas are now subject to the maintenance plans that were approved by EPA and the areas must continue to attain the standard for the first maintenance period of ten years. High values of monitored PM_{10} sometimes result from exceptional events, such as dust storms and wildfires.

$PM_{2.5}$

The EPA first established standards for $PM_{2.5}$ in 1997. In 2006, the EPA lowered the 24-hour $PM_{2.5}$ standard from 65µg/m3 to 35 µg/m3. The $PM_{2.5}$ NAAQS underwent a review in 2020 and the standards were retained. In 2009, three areas in Utah were designated nonattainment for $PM_{2.5}$. UDAQ wrote a moderate SIP for the Logan, UT-ID nonattainment area, including a vehicle emissions inspection program. Logan attained the standard, and has since been redesignated to attainment status. The Provo and Salt Lake $PM_{2.5}$ nonattainment areas were unable to attain by the moderate attainment date and were reclassified to serious nonattainment. A serious SIP was submitted to EPA for the Salt Lake nonattainment area, and the Provo nonattainment area attained the standard prior to a serious SIP due date. Best Available Control Measures and Technologies were still required in both nonattainment areas, significantly reducing VOCs, NO_x, and both primary and secondary $PM_{2.5}$ in the airsheds. Both areas have now attained the standard, and EPA is reviewing SIP elements and maintenance plans for official redesignation to attainment/maintenance.

Sulfur Dioxide (SO_2)

In 1971, EPA established a 24-hour average SO_2 standard of 0.14 ppm, and an annual arithmetic average standard of 0.030 ppm. In 2010, EPA revised the primary standard for SO_2, setting it at 75 ppb for a three-year average of the 99^{th}percentile of the annual distribution of daily maximum one-hour average concentrations for SO_2. Throughout the 1970s, the Magna monitor routinely measured violations of the 1971 24-hour standard. Consequently, all of Salt Lake County and parts of eastern Tooele County above 5,600 feet were designated as nonattainment for that standard. Two significant technological upgrades at the Kennecott smelter costing the company nearly one billion dollars resulted in continued compliance with the SO_2 standard since 1981. In the mid-1990s, Kennecott, Geneva Steel, the five refineries in Salt

Lake City, and several other large sources of SO_2 made dramatic reductions in emissions as part of an effort to curb concentrations of secondary particulates (sulfates) that were contributing to PM_{10} violations. More recently, Kennecott closed Units 1, 2, and 3 of its coal-fired power plants in 2016 and Unit 4 in 2019, resulting in further SO_2 emissions reductions.

Utah submitted an SO_2 Maintenance Plan and redesignation request for Salt Lake and Tooele Counties to the EPA in April of 2005, but EPA never took formal action on the request. Because of changes in the emissions in subsequent years, and changes in the modeling used to demonstrate attainment of the standard, in November 2019, the State of Utah withdrew its 2005 Maintenance Plan and redesignation request. UDAQ is currently working very closely with EPA to develop a new maintenance plan and redesignation request to address the 1971 standard. UDAQ will conduct modeling and other analyses in 2021 with the goal of submitting an approvable maintenance plan and redesignation request to EPA by the end of that year. On November 1, 2016, Governor Herbert submitted a recommendation to EPA that all areas of the state be designated as attainment for the 2010 SO_2 NAAQS based on monitoring and air quality modeling data. On January 9, 2018, EPA formally concurred with this recommendation and designated all areas of the state as attainment/unclassifiable.

The NAAQS program and Utah's work to stay in compliance with all NAAQS has significantly decreased VOC, NO_x, $PM_{2.5}$, PM_{10}, and SO_2 emissions over time, benefiting the regional haze program.

Air Quality Incentive Programs

In addition to the NAAQS program, UDAQ administers multiple incentive programs created to encourage individuals and businesses to voluntarily reduce emissions. Funding for these programs comes from various sources, including settlement agreements, legislative appropriations, and federal grant programs. The emissions reductions from incentive programs are not included as part of any SIP, but the reductions do make an impact on monitored ambient values.

Targeted Airshed Grants

UDAQ has been a recipient of EPA targeted airshed grants in the past for $PM_{2.5}$ and ozone in Logan, Salt Lake, Provo, and the Uinta Basin nonattainment areas. Programs include woodstove/fireplace conversions, school bus replacements, vehicle repair and replacement assistance programs, and an oil and gas engine replacement program. UDAQ applied for the competitive grants and was awarded a total of $14.5 million for these projects that are still in process.

Utah Clean Diesel Program

The Utah Clean Diesel Program aims to cut emissions from heavy- duty diesel vehicles and equipment that operate in the State's nonattainment areas. Fleet owners receive a 25% incentive toward the purchase of new vehicles and equipment that meet the cleanest emissions standards. Retiring engine model years 2006 and older diesel trucks that are currently operational and have a minimum of three years remaining in their useful life and replacing them with current model years can achieve approximately 71 to 90% reductions in NO_x, 97 to 98%

reductions in $PM_{2.5}$, and 89 to 91% reductions in VOCs, according to the EPA Emissions Standards for Heavy-Duty Highway Engines and Vehicles. Nearly $24 million in federal grants have been awarded through the Utah Clean Diesel Program since 2008, resulting in thousands of tons reduced from diesel emissions.

Legislative Appropriations for Incentive Programs

The woodstove and fireplace conversion funded by the targeted airshed grant was wildly successful, and the Utah State Legislature appropriated UDAQ an additional $9 million to convert wood burning appliance to gas or electric along Utah's Wasatch Front. This program is currently being administered. During the 2019 General Legislative Session, the State Legislature appropriated $4.9 million to be used as an incentive for the installation of electric vehicle supply equipment (EVSE) throughout the State. The EVSE Incentive Program allows businesses, non-profit organizations, and other governmental entities (excluding State Executive Branch agencies) to apply for a grant for reimbursement of up to 50% of the purchase and installation costs for a pre-approved EVSE project. Funds can be used for the purchase and installation of both Level 2 or DC fast charging EVSE. This program continues to be administered. During the 2019 Legislative Session, the Legislature appropriated $500,000 to the UDAQ to administer a Trip Reduction Program. A primary component of the Trip Reduction Program is a Free-Fare Day Pilot Project. The UDAQ has worked closely with the Utah Transit Authority (UTA) to provide free fares during inversion periods when air quality levels are increasing and projected to reach levels that are harmful to human health.

Clean Air Violation Settlement Dollars for Emissions Reduction Incentives

The State of Utah is a beneficiary of over $35 million from the Volkswagen (VW) Environmental Mitigation Trust, part of a settlement with VW for violations of the CAA. UDAQ has developed an environmental mitigation plan to offset the NO_x emissions from the vehicles in the State affected by the automaker's violations. The plan directs the $35 million settlement funds towards upgrades to government-owned diesel truck and bus fleets as well as the expansion of electric-vehicle (EV) charging equipment. Funding allocations are as follows:

- Class 4-8 Local Freight Trucks and School Bus, Shuttle Bus, and Transit Bus: 73.5%
- Light-Duty, Zero Emissions Vehicle Supply Equipment: 11%
- Administrative Costs: 8.5%
- Diesel Emission Reduction Act (DERA) options: 7%

Projects were prioritized and selected based on their reduction of NO_x, cost-per-ton of NO_x reduced, value to the nonattainment areas, and community benefits. Awardees will have three years to complete their projects.

Using settlement money from General Motors, UDAQ runs an electric lawn equipment exchange each year. Participants receive a higher incentive dollar amount if they scrap an old gas-powered piece of equipment.

6.A.6 Measures to Mitigate the Impacts of Construction Activities

Fugitive dust is particles of soil, ash, coal, minerals, etc., which become airborne because of wind or mechanical disturbance. Fugitive dust can be generated from natural causes such as wind or from manmade causes such as unpaved haul roads and operational areas, storage, hauling and handling of aggregate materials, construction activities and demolition activities. Fugitive dust contributes particulate matter (PM) emissions to the atmosphere. PM emissions must be minimized to meet NAAQS. Fugitive dust is limited to an opacity of 20% or less on site, and 10% or less at the property boundary. Opacity is a measurement of how much visibility is obscured by a plume of dust. For example, if a plume of dust obscures 20% of the view in the background, the visible emissions from the dust plume is 20% opacity. The regulations described in this Subsection apply to the following areas of the state:

- all regions of Salt Lake and Davis counties
- all portions of the Cache Valley
- all regions in Weber and Utah counties west of the Wasatch Mountain range
- in Box Elder County, from the Wasatch Mountain range west to the Promontory Mountain range and south of Portage
- in Tooele County, from the northernmost part of the Oquirrh mountain range to the northern most part of the Stansbury Mountain range and north of Route 199.

In addition to opacity limits, any source 0.25 acre or greater in size is required to submit a Fugitive Dust Control Plan (FDCP) to the UDAQ. The FDCP is required to help sources minimize the amount of fugitive dust generated onsite. A source is required to submit a FDCP prior to initial construction or operation and prior to any modifications made on site that effect fugitive dust emissions. Sources are required to maintain records indicating compliance with the conditions of a FDCP. For high wind events (winds over 25 miles per hour) additional records are required. The sources must make these records available for review by the UDAQ upon request.

There are also regulations regarding possible fugitive dust from roadways:

- Any person whose activities result in fugitive dust from a road shall minimize fugitive dust to the maximum extent possible.
- Any person who deposits materials that may create fugitive dust on a public or private paved road shall clean the road promptly.
- Any person responsible for construction or maintenance of any existing road or having a right-of-way easement or possessing the right to use a road shall minimize fugitive dust to the maximum extent possible.
- Any person responsible for construction or maintenance of any new or existing unpaved road shall prevent, to the maximum extent possible, the deposit of material from the unpaved road onto any intersecting paved road during construction or maintenance. This includes site entrances and exits for vehicles.
- Demolition activities including razing homes, buildings, or other structures.

6.A.7 Basic smoke management practices

Subsection 51.309(d)(6) of Title 40 Code of Federal Regulations includes the following requirements for state implementation plans regarding programs related to fire: (1) documentation that all federal, state and private prescribed fire programs in the state evaluate and address the degree of visibility impairment from smoke in their planning and application; (2) a statewide inventory and emissions tracking system for VOCs, NO_x, elemental and organic carbon, and fine particle emissions from fire; (3) identification and removal of any administrative barriers to the use of alternatives to burning where possible; (4) inclusion of enhanced smoke management programs considering visibility as well as health and nuisance objectives based on specific criteria; (5) and establishment of annual emission goals for fire in cooperation with states, tribes, federal land managers and private entities to minimize emissions increases from fire to the maximum extent feasible.

Utah implements an EPA-approved Smoke Management Plan (SMP) to regulate open burning and prescribed fire activities. Utah has developed a smoke management regulation (found in Utah Administrative Code r. R307-204) that implements the Western Regional Air Partnership (WRAP) Enhanced Smoke Management Programs for Visibility Policy. The SMP considers smoke management techniques and the visibility impacts of smoke when developing, issuing or conditioning permits, and when making dispersion forecast recommendations. Pursuant to 40 CFR § 51.309(d)(6)(i), the State of Utah has evaluated all federal, state, and private prescribed fire programs in the state, based on the potential to contribute to visibility impairment in the 16 CIAs of the Colorado Plateau, and how visibility protection from smoke is addressed in planning and operation. The State of Utah relied upon the WRAP report Assessing Status of Incorporating Smoke Effects into fire Planning and Operation as a guide for making this evaluation. The State of Utah has also evaluated whether these prescribed fire programs contain the following elements: actions to minimize emissions; evaluation of smoke dispersion; alternatives to fire; public notification; air quality monitoring; surveillance and enforcement; and program evaluation.

The Utah Smoke Management Plan (SMP), revised March 23, 2000, provides operating procedures for federal and state agencies that use prescribed fire, wildfire, and wildland fire on federal, state, and private wildlands in Utah. The SMP includes the program elements listed in 40 CFR § 51.309(d)(6)(i), except for alternatives to fire. In a letter dated November 8, 1999, the EPA certified the Utah SMP under EPA's April 1998 Interim Air Quality Policy on Wildland and Prescribed Fires (Policy). EPA's Policy also includes the elements that are listed in 40 CFR § 51.309(d)(6)(i).

In 2001, the Utah SMP requirements were codified through rulemaking and comprise R307-204 of the Utah Administrative Code. R307-204 applies to all persons using prescribed fire or wildland fire on land they own or manage, including federal, state, and private wildlands. The Utah TSD Supplement includes copies of the Utah SMP.

Under R307-204, Land Managers are required to submit pre-burn information including the location of any CIAs within 15 miles of the burn, a map depicting the potential impact of the smoke from the burn on any CIAs, a description of fuels and acres to be burned, emission reduction techniques to be applied, and monitoring of smoke effects to be conducted. In addition, Land Managers are required to submit a more detailed burn plan that includes, at a minimum, information on the fire prescription or conditions under which a prescribed fire may be ignited.

Under R307-204, prescribed fires requiring a burn plan cannot be ignited and wildland fire used for resource benefits cannot be managed before the UDAQ Director approves the burn request. The burn approval requirement provides for the scheduling of burns to reduce impacts on visibility in CIAs.

After the burn is completed, the Land Manager is required to submit post-burn information (daily emission report) to evaluate the effectiveness of the burn and provide a record of acres treated by the burn, emissions information, public interest, daytime and nighttime smoke behavior, any emission reduction techniques applied, and evaluation of those techniques. The procedures listed above serve as an evaluation of the degree of visibility impairment from smoke from prescribed fires that are conducted on federal, state, and private wildlands.

Information on the types of management alternatives to fire considered by Land Managers are included in programmatic or long-term management plans. These programmatic plans are developed in accordance with the National Environmental Policy Act (NEPA) and are reviewed by the UDAQ on an individual basis. Typically, the Land Manager does not evaluate alternatives to fire once the decision has been made to use fire and the subsequent burn plan developed.

6.A.8 Emissions Limitations and Schedules for Compliance to Achieve the RPG

The 2028OTBa2 modeled visibility projections from WRAP for Utah are based on recent actual emissions and activities of in-state sources. These projections are compared to the URP glidepaths in section 8.C. As shown in Table 26 (section 6.A.10), Utah is making reasonable progress in each of its parks and is projected to continue that progress through 2028 on the assumption that Utah sources continue operating within the confines of these “on-the-books” emissions trends. Section 8.D contains Utah’s reasonable progress determinations detailing emissions limits and controls UDAQ has deemed necessary for Utah to achieve reasonable progress in its CIAs. Emissions limitations and schedules for compliance for the second planning period may be found in SIP Subsection IX.H.23.[126]

6.A.9 Source retirement and replacement schedules

Table 25 details the planned EGU retirement and replacement schedules for Utah sources used in WRAP’s RepBase2 and 2028OTBa2 modeling projections. Of all of the planned retirements, only the announced retirement of the Intermountain Generation Station in 2025 occurs within the second planning period. Though the IGS coal-fired units are expected to cease operation by mid-2025, Utah is establishing a firm closure date of no later than December 31, 2027, to

[126] See Appendix A

ensure that these units will not continue to operate beyond the end of the second planning period. This date allows flexibility for closing the plant and the rescinding of the permit and approval order.

Table 25: Status of Utah EGU Retirements in RepBase2 and 2028OTBa2 Inventories

Facility Name	Unit ID	In-Service Year	Retirement Year	Notes	Operator	Unit Type
Intermountain	1SGA	1986	2025	Announced retirement	Intermountain Power Service Corporation	Dry bottom wall-fired boiler
Intermountain	2SGA	1987	2025	Announced retirement	Intermountain Power Service Corporation	Dry bottom wall-fired boiler
Bonanza	1-Jan	1986	2030	Coal consumption cap from settlement agreement	Deseret Generation & Transmission	Dry bottom wall-fired boiler
Hunter	1	1978	2042	PAC IRP; Round 1 RH FIP in Litigation	PacifiCorp Energy Generation	Tangentially-fired
Hunter	2	1980	2042	PAC IRP; Round 1 RH FIP in Litigation	PacifiCorp Energy Generation	Tangentially-fired
Hunter	3	1983	2042	PAC IRP	PacifiCorp Energy Generation	Dry bottom wall-fired boiler
Huntington	1	1977	2036	PAC IRP; Round 1 RH FIP in Litigation	PacifiCorp Energy Generation	Tangentially-fired
Huntington	2	1974	2036	PAC IRP; Round 1 RH FIP in Litigation	PacifiCorp Energy Generation	Tangentially-fired

6.A.10 Anticipated net effect on visibility from projected changes in emissions during this planning period

According to the RHR, the 2028 RPG for the 20 percent most anthropogenically impaired days is to be compared to the 2000-2004 baseline period visibility condition for the same set of days and must provide for visibility improvement since the baseline period.[127] UDAQ has used modeling data from WRAP's TSS to project the anticipated net effect on visibility progress that will occur in the second planning period based on already adopted controls and "on-the-books" activities and emissions rates. UDAQ has chosen the "2028OTBa2 w/o fire" projection that excludes wildfire to more accurately represent future emissions from sources UDAQ is better able to control. This projection reduces the impact of elemental carbon and organic carbon from

[127] 40 CFR 51.308(f)(3)(i)

fires from the original 2028 EPA projection to remove additional fire impacts that were not fully eliminated by the move from haziest days metric (used during the first planning period) to most impaired days metric (used during the second planning period). These projections result from in-state emission reductions due to ongoing air pollution control programs, including source measures the state has already adopted to meet RHR requirements and CAA requirements other than for visibility protection.

Long Term Strategy Summary

UDAQ's long term strategy (LTS) includes an array of existing and new measures as detailed below.

Existing Measures

UDAQ relied upon several existing measures in the development of its LTS, including federal on-road and non-road vehicle and equipment standards and BACM measures and BACT controls included in the recently completed Serious Area PM2.5 SIP for the Salt Lake Nonattainment Area. Utah also relied upon the following existing round 1 regional haze controls:

- Existing NO_x control rate-based limits and Hunter power plant
- Existing NO_x control rate-based limits and Huntington power plant
- Existing SO_2 limits for Hunter power plant (Section 309 control added to SIP in round 2)
- Existing SO_2 limits for Huntington power plant (Section 309 control added to SIP in round 2)
- Closure of the Carbon power plant

UDAQ also added existing controls/limits on haze-forming pollutants at screened-in facilities to the round 2 SIP to ensure ongoing enforceability in the regional haze context:

- Graymont
- Ash Grove
- Sunnyside
- US Magnesium
- Intermountain Generation Station

Most of the above measures are already accounted for in the WRAP 2028OTBa2 scenario, which was based on the emission inventories and data sources listed in Section 5.B of this SIP revision. However, two existing measures led to additional emissions reductions that were not accounted for in the WRAP 2028OTBa2 projections:

- $PM_{2.5}$ SIP BACT SCR level NO_x rate-based limit and subsequent closure of the Kennecott Utah Copper power plant
- $PM_{2.5}$ SIP BACT annual mass-based SO_2 limit at the Tesoro Refinery

New Measures

As stated previously UDAQ required four-factor analyses on six sources with Q/d values >=6 that met additional screening criteria. These analyses informed the reasonable progress determinations for these sources and led to the inclusion of the following new measures in the LTS:

- A plantwide enforceable mass-based NO_x limit on Hunter power plant
- A plantwide enforceable mass-based NO_x limit on Huntington power plant
- Installation of FGR on the US Magnesium Rowley Plant Riley Boiler
- An enforceable closure date for Units 1 and 2 of the Intermountain Generation Station

Emissions reductions for one of these new measures, the closure of IGS Units 1 and 2, were already accounted for in the WRAP 2028OTBa2 projections based upon closure plans that had been announced at the time the scenario was developed.

Table 26 below summarizes estimated net changes to the 2028 projection based upon the inclusion of both new and existing measures in the LTS. The emission reductions from the KUC power plant were estimated based on the elimination of the EGU emissions from that facility from the 2028OTBa2 scenario. The SO_2 emission reductions for the Tesoro Refinery were estimated by reducing the 2028OTBa2 SO_2 emissions for that facility (708 tons) to the SIP Section IX.H source-wide SO_2 annual limit of 300 tons per year, resulting in a reduction of 408 tons. The remaining emission reductions stem from the four-factor analyses and reasonable progress determinations for the sources listed.

Table 26: Net Changes in Emissions from New and Existing Measures Relative to 2028OTBa2

Source/Facility	New or Existing Measure	Reduction Included in 2028OTBa2	NO_X	SO_2	PM_{10}-PRI	$PM_{2.5}$-PRI	VOC	NH_3
PacifiCorp- Hunter Power Plant	New	No	-158	0	0	0	0	0
PacifiCorp- Huntington Power Plant	New	No	149	0	0	0	0	0
US Magnesium Riley Boiler	New	No	-23	0	0	0	0	0
Tesoro Refining & Marketing Company LLC	Existing	No	0	-408	0	0	0	0
Kennecott Utah Copper LLC- Power Plant	Existing	No	-1,152	-2,152	-135	-99	-6	0
Total			-1,184	-2,560	-135	-99	-6	0

Based upon these changes, UDAQ revised the original 2028OTBa2 projection as summarized in Table 27. The resulting 2028LTS scenario results in emissions reductions of 44% (NOx), 27% (SO2), 2% (PM10), 10% (PM2.5) and 30% (VOC) relative to RepBase2.

Table 27: Statewide Anthropogenic Scenario Totals and LTS Emission Reductions (tpy)

Source Category	2014v2	RepBase2	2028OTBa2	Change Due to New and Existing Measures	2028LTS	2028LTS-RepBase2	2028LTS-RepBase2 (% Change)
NO_X	179,639	154,328	87,593	-1,184	86,409	-67,919	-44%
SO_2	27,829	15,253	13,684	-2,560	11,124	-4,129	-27%
PM_{10}	118,235	120,542	118,117	-135	117,982	-2,560	-2%
$PM_{2.5}$	28,547	31,050	28,039	-99	27,940	-3,110	-10%
VOC	240,496	244,272	171,298	-6	171,292	-72,980	-30%
NH_3	20,523	20,995	21,011	0	21,011	16	0%

Because the LTS was developed after the completion of the WRAP photochemical modeling, the additional reductions from the LTS relative to 2028OTBa2 are not expressly accounted for in the modeled reasonable progress goal. The omission of these emissions reductions in the 2028OTBa2 projection make our glidepath comparisons conservative, as actual 2028 visibility can be expected to improve due to additional emission reductions associated with the LTS.

Visibility Comparison

Table 28 compares the baseline visibility data for each of Utah's CIAs with the 2028 point along the URP glidepath and the 2028 modeled projections and calculates the resulting percentage of progress towards the 2028 URP made in each.

Table 28: Comparison of baseline, 2028 URP, 2028 EPA w/o fire projection for worst and clearest days

CIA IMPROVE Site	WORST DAYS					CLEAREST DAYS			
	Baseline (dv)	2028 URP (dv)	2028 EPA w/o Fire Projection (dv)	% Progress to 2028 URP	2028 Below URP Glidepath? (Y/N)	Baseline (dv)	2028 EPA Projection (dv)	2028 EPA w/o Fire Projection (dv)	2028 Below No Degradation Line? (Y/N)
BRCA1	8.42	6.68	6.03	137.60%	YES	2.77	1.22	1.20	YES
CANY1	8.79	6.92	6.19	139.10%	YES	3.75	1.94	1.92	YES
CAPI1	8.78	6.87	6.63	112.28%	YES	4.10	2.17	2.10	YES
ZICA1	10.40	8.35	8.27	103.73%	YES	4.48	3.65	3.54	YES

The following figures compare the modeled 2002, representative baseline, and 2028 projections with source apportionment for most impaired days to show the visibility progress made in Utah's CIAs.

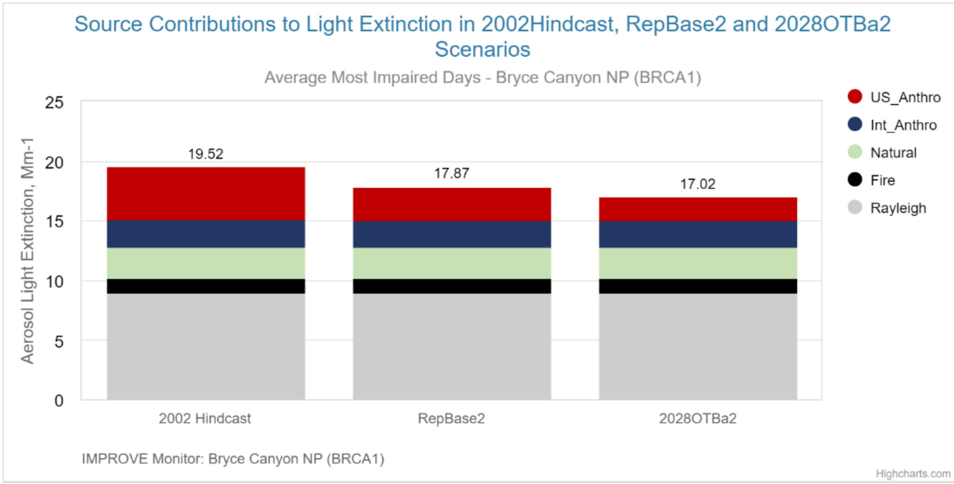

Figure 41: Modeled Visibility Progress for MID at Bryce Canyon National Park

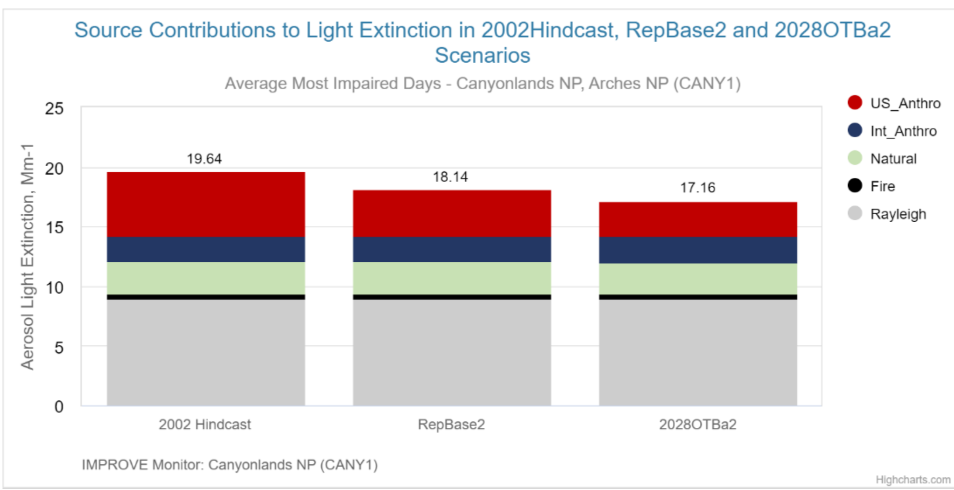

Figure 42: Modeled Visibility Progress for MID at Canyonlands and Arches National Park

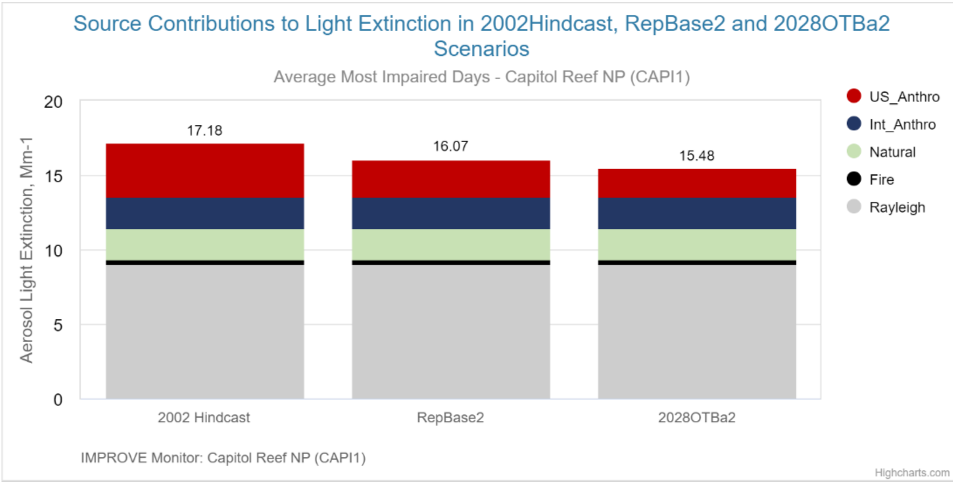

Figure 43: Modeled Visibility Progress for MID at Capitol Reef National Park

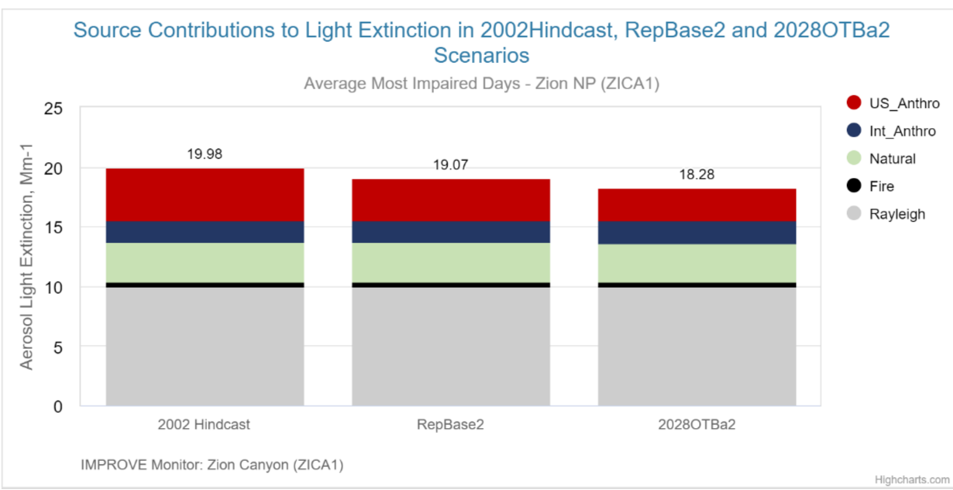

Figure 44: Modeled Visibility Progress for MID at Zion National

The following figures represent the visibility progress made in each CIA based on only US anthropogenic contribution with the same modeling projections for most impaired days.

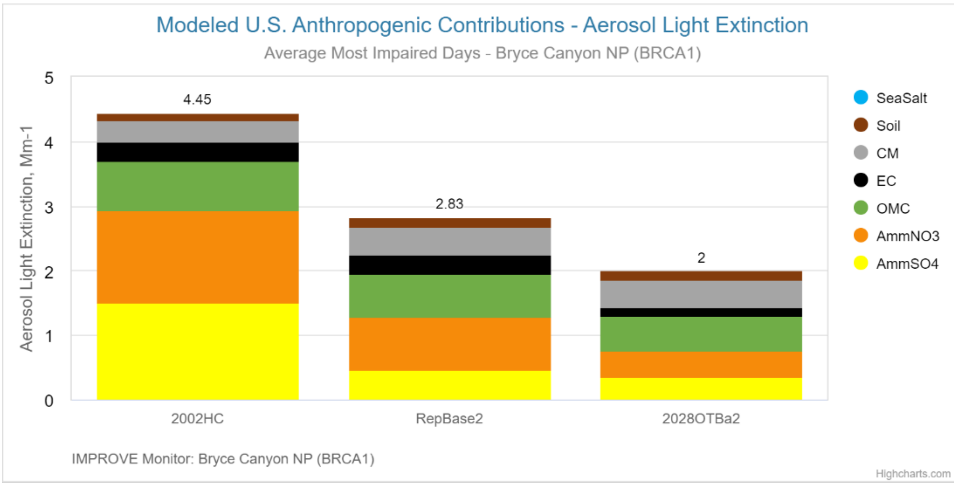

Figure 45: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Bryce Canyon National Park

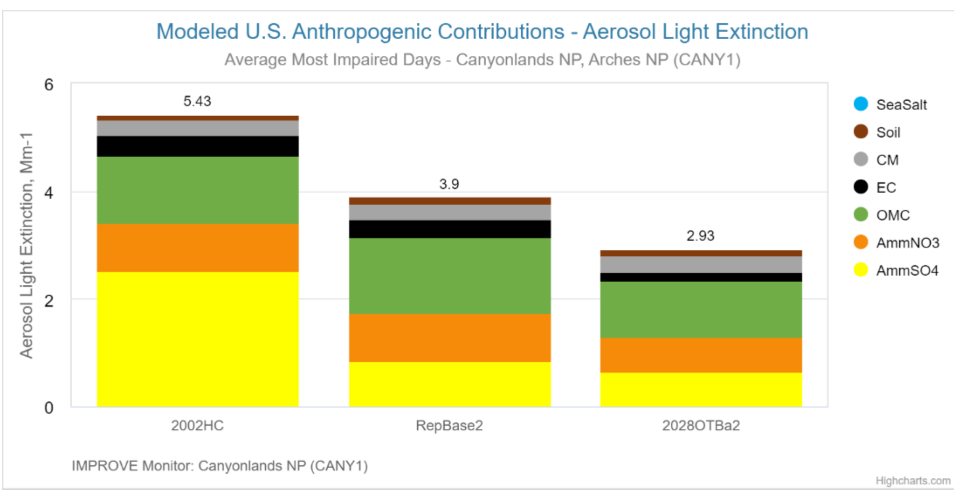

Figure 46: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Canyonlands and Arches National Park

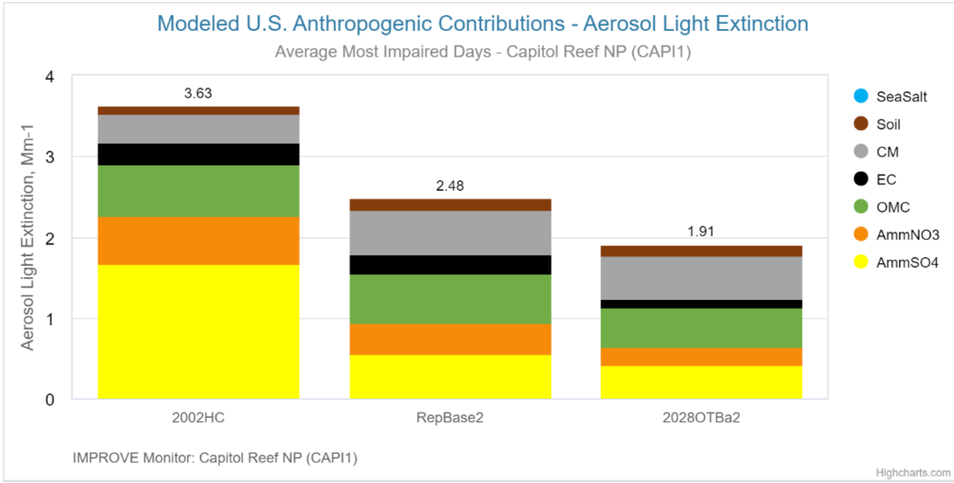

Figure 47: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Capitol Reef National Park

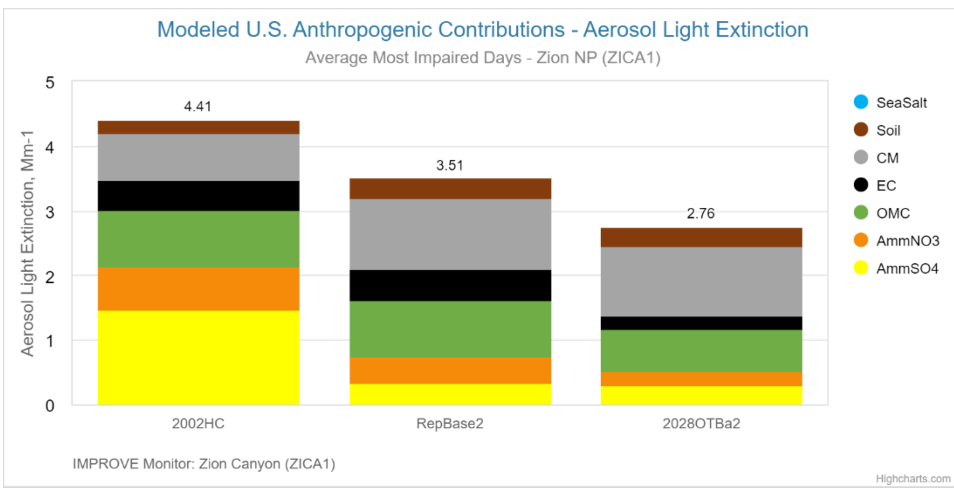

Figure 48: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Zion National Park

6.A.11 Enforceability of Emissions Limitations

Any emissions limits and operating procedures identified for the implementation of the RHR are listed in SIP Subsection IX.H.21, 22, and 23, which are made enforceable through EPA approval and incorporation into the Utah Air Quality Rules. The proposed IX.H language can be found in Appendix A. Existing control measures from UDAQ's $PM_{2.5}$ and PM_{10} SIP revisions deemed necessary for reasonable progress can be found in IX.H.2, 4, and 12.

Chapter 7: Emission Control Analysis[128]

7.A Source Screening

Through modeling done by WRAP with data collected at the IMPROVE sites in Utah's CIAs, UDAQ was able to assess the source apportionment for the most impaired days in Utah's National Parks. Figure 49 shows that, on most impaired days, US anthropogenic, international, and biogenic pollution are the most significant sources of light extinction. Figure 50 and Figure 51 further apportion species contributing to each pollution source. US anthropogenic impairment consists primarily of organic mass carbon, coarse mass, ammonium nitrate, and ammonium sulfate. For this implementation period, Utah has focused on visibility impairing pollutants attributed to anthropogenic sources which can be controlled including ammonium nitrate and ammonium sulfate.

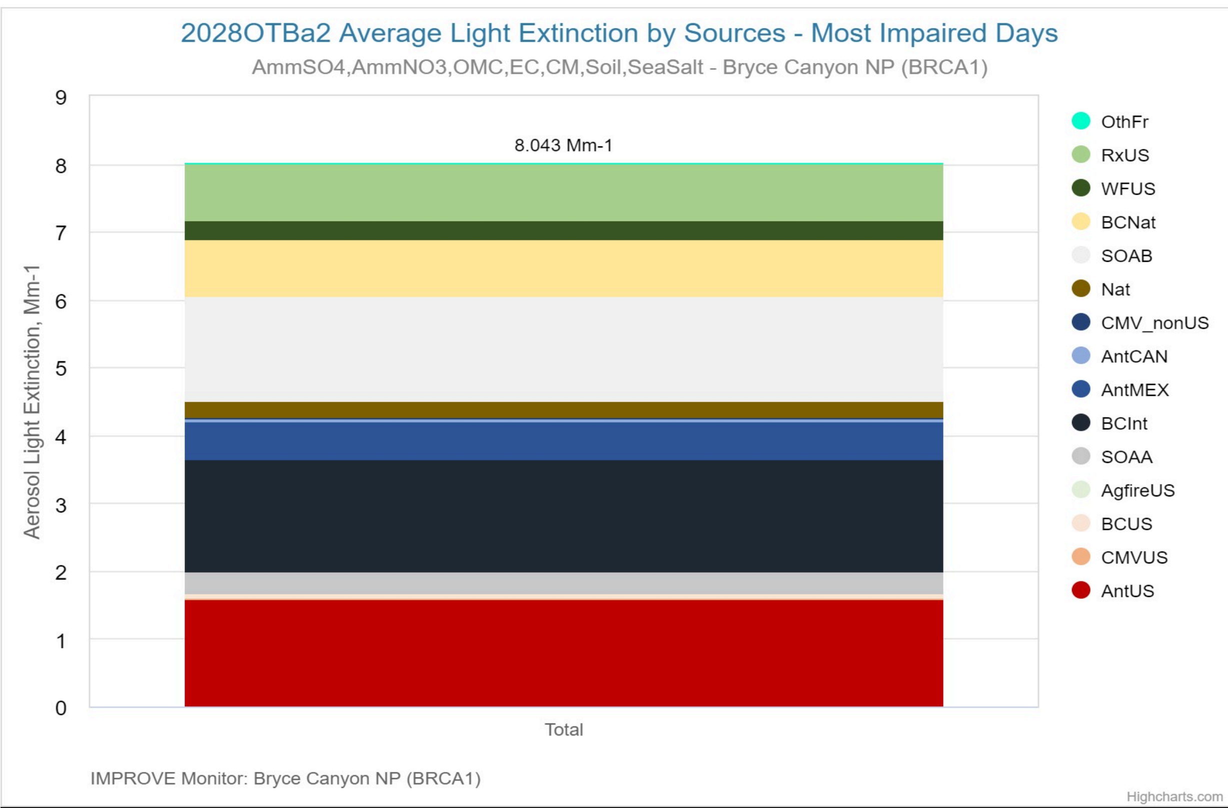

Figure 49: Average Light Extinction by Sources in Bryce Canyon National Park

128 40 CFR 51.308(f)(2)(i)

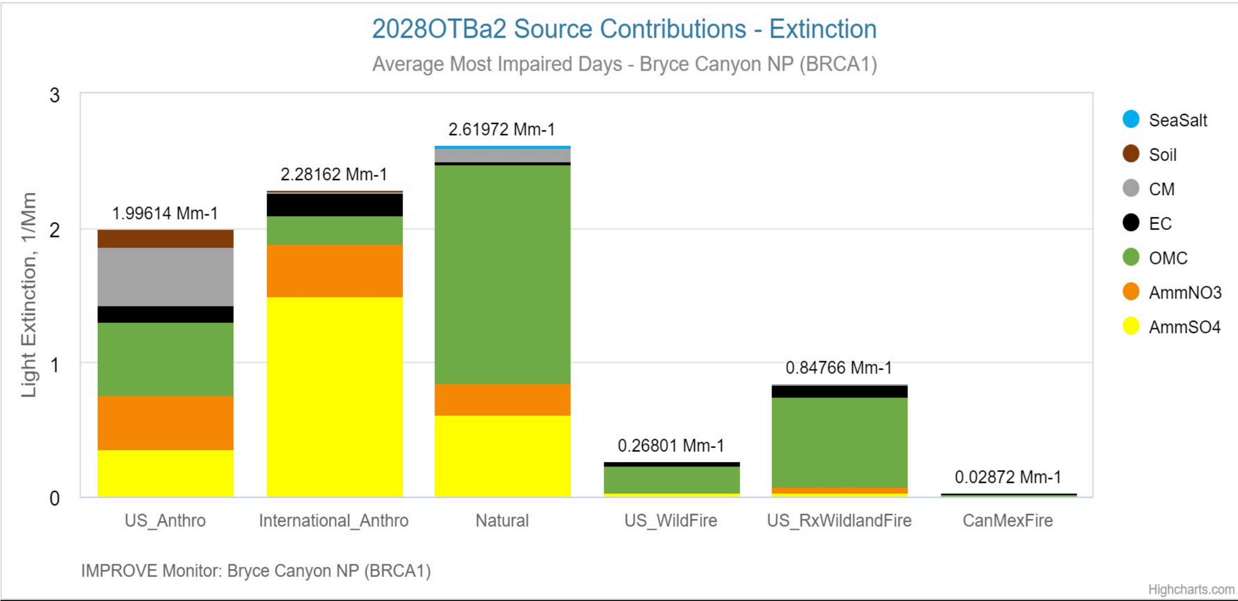

Figure 50: Source Contributions on Average Most Impaired Days in Bryce Canyon National Park

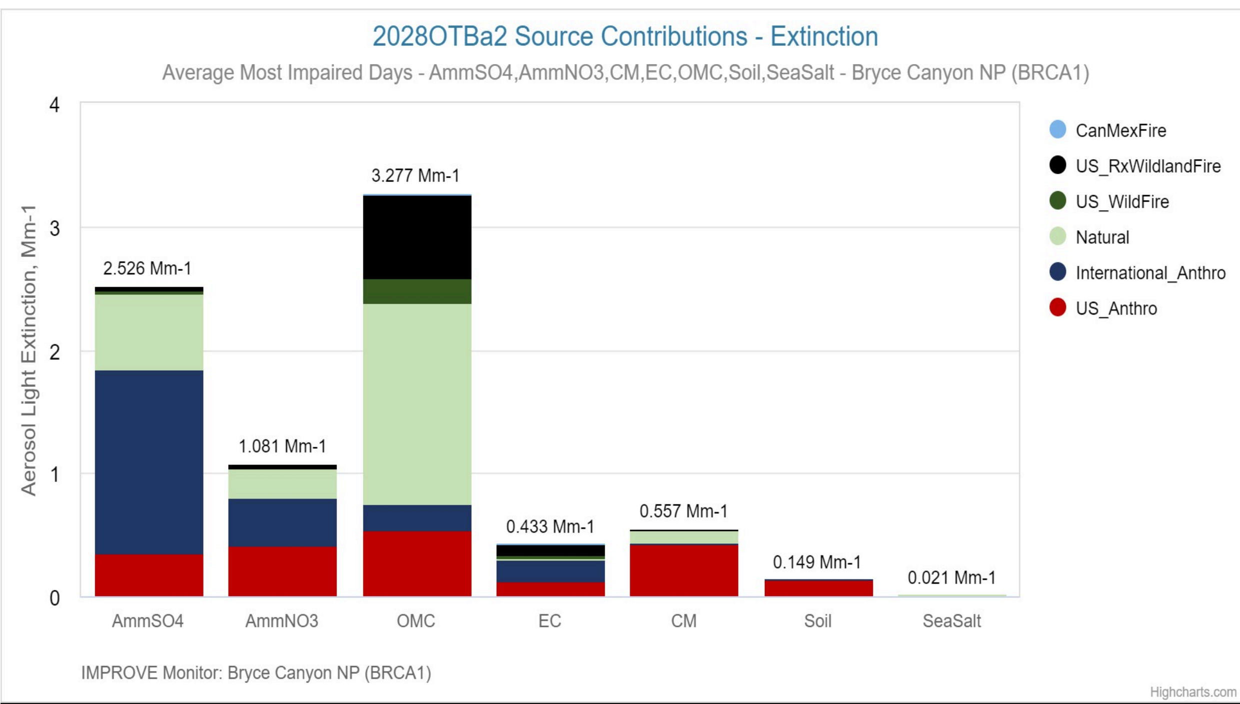

Figure 51: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Bryce Canyon National Park

The regulated sources included in the map below consist of point sources and oil and gas wells within Utah. There are 37 sources emitting pollutants greater than 100 TPY (major sources) and

511 other point sources emitting less than 100 TPY. There are 13,853 oil and gas wells in Utah, including all "shut-in" wells which are not currently in use, but could resume production at any time, which would be documented by reports from the Utah Division of Oil, Gas, and Mining (UDOGM).

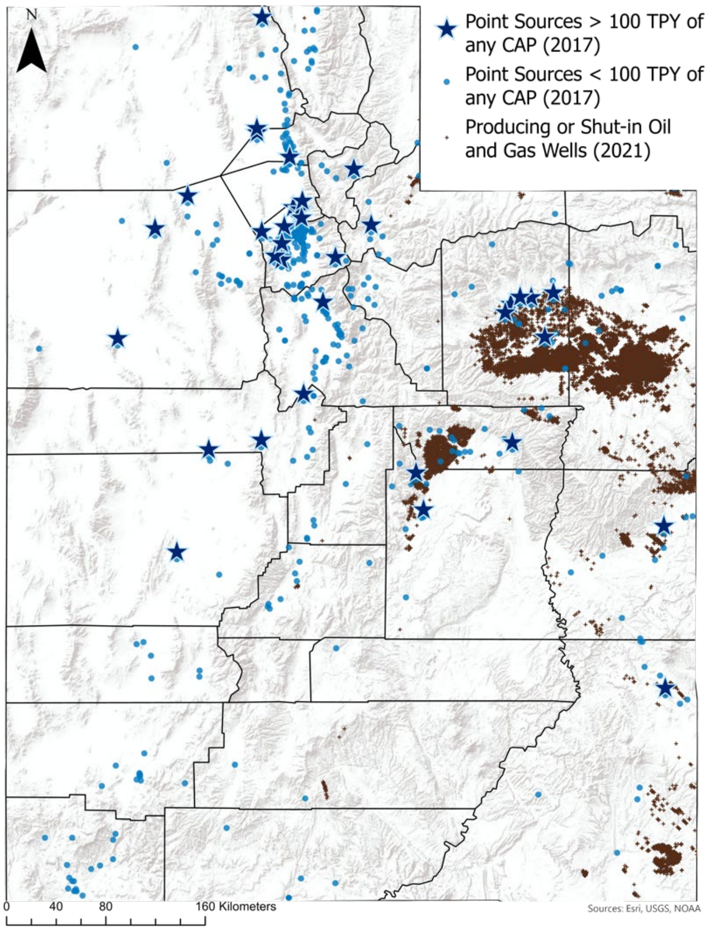

Figure 52: Map of Utah Regulated Sources with Emissions >100 TPY

7.A.1 Q/d Analysis

The RHR[129] requires states to consider anthropogenic sources of visibility impairment and should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. Sources in Utah were selected based on a Q/d analysis. The analysis is a ratio of a source's emissions in tons per year (Q) in 2014 divided by the distance (d) in kilometers to any Class I area. Emissions in tons per year of SO_2, NO_x, and PM were

[129] 40 C.F.R. § 51.308(f)(2).

included in the analysis. WRAP's analysis suggested using a Q/d value of 10 as the threshold for sources with the most potential to impact CIAs. However, UDAQ used a more conservative threshold of six.[130]

Table 29: Sources initially selected to perform a Four-Factor analysis

Facility Name	Combined Q/d	Total Q tpy*	Distance to Nearest Class I area in km (D)	Class I Area	Q/d NO_x	Q/D SO_2	Q/D PM_{10}	NO_x tons per year (Q)	SO_2 tons per year (Q)	PM_{10} tons per year (Q)
Ash Grove Cement Company- Leamington Cement Plant	6.9	930.5	134.0	Capitol Reef	6.3	0.04	0.6	845.5	5.9	79.1
CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant†	20.9	747.1	35.8	Canyonlands	5.3	14.0	1.6	188.6	499.6	59.0
Graymont Western Us Incorporated- Cricket Mountain Plant	9.0	1,180.7	130.8	Capitol Reef	7.0	0.3	1.7	916.5	40.8	223.4
Intermountain Power Service Corporation- Intermountain Generation Station†	193.6	28,945.7	149.5	Capitol Reef	153.3	29.2	11.1	22,909.2	4,371.5	1,665.0
Kennecott Utah Copper LLC- Mine & Copperton Concentrator†	22.1	5,234.5	237.2	Capitol Reef	17.7	0.01	4.4	4,199.6	2.0	1,032.9
Kennecott Utah Copper LLC- Power Plant, Lab, and Tailings Impoundment†	11.8	2,949.7	250.4	Capitol Reef	5.3	6.0	0.5	1,322.5	1,500.3	126.8
PacifiCorp- Hunter Power Plant	216.1	16,177.9	74.9	Capitol Reef	153.5	52.6	10.0	11,491.2	3,939.3	747.4
PacifiCorp- Huntington Power Plant	105.5	10,106.2	95.8	Capitol Reef	71.7	25.9	7.9	6,871.6	2,479.2	755.4
Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility	15.2	1,477.1	97.0	Arches	3.6	10.9	0.8	348.9	1,054.8	73.4
US Magnesium LLC- Rowley Plant	7.4	2,124.2	288.7	Capitol Reef	3.6	0.1	3.7	1,052.1	17.9	1,054.2
	*Tons per year: Data is from version 2 of the 2014 National Emissions Inventory † Additional data from these sources, including recent emissions, projected 2028 emissions, and planned closure, allowed them to be exempt from a 4-factor analysis									

Because the original Q/d analysis used 2014 NEI data, UDAQ also conducted a follow-up Q/d screen using more recently available 2017 NEI data to ensure that the source selection results

[130] See Table 27

remained consistent and that no sources with potential impacts were missed. No additional sources were identified with Q/d >=6. One source, CCI Paradox Lisbon Natural Gas Plant, was not selected as the plant was not in operation that year and had no emissions. Also, the 2017 NEI does not include haul truck emissions from the KUC Mine & Copperton Concentrator, resulting in a Q/d of 3.9 for that source. UDAQ elaborates on this source in Section 7.A.2 below.

Table 30: 2017 NEI Q/d Screen

Facility Name	Combined Q/d	Total Q tpy*	Distance to Nearest Class I area in km (D)	Class I Area	Q/d NO_x	Q/D SO_2	Q/D PM_{10}	NO_x tons per year (Q)	SO_2 tons per year (Q)	PM_{10} tons per year (Q)
Ash Grove Cement Company- Leamington Cement Plant	9.8	1,319.3	134.0	Capitol Reef	8.8	0.14	0.9	1,183.8	19.0	116.5
CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant†	NA	NA	35.8	Canyonlands	NA	NA	NA	NA	NA	NA
Graymont Western Us Incorporated- Cricket Mountain Plant	6.3	823.8	130.8	Capitol Reef	4.07	0.13	2.1	532.7	17.5	273.6
Intermountain Power Service Corporation- Intermountain Generation Station†	85.5	12,785.0	149.5	Capitol Reef	62.3	16.6	6.6	9,318.8	2,483.6	982.6
Kennecott Utah Copper LLC- Mine & Copperton Concentrator††	3.9	931.6	237.2	Capitol Reef	0.02	0.00	3.9	5.2	0.0	926.4
Kennecott Utah Copper LLC- Power Plant, Lab, and Tailings Impoundment†	6.3	1,570.1	250.4	Capitol Reef	1.8	4.1	0.3	460.8	1,036.4	73.0
PacifiCorp- Hunter Power Plant	184.2	13,789.1	74.9	Capitol Reef	130.6	46.9	6.7	9,773.8	3,511.6	503.8
PacifiCorp- Huntington Power Plant	90.7	8,686.0	95.8	Capitol Reef	61.9	23.8	5.0	5,931.2	2,281.0	473.8
Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility	10.0	965.4	97.0	Arches	4.4	4.9	0.6	428.0	477.0	60.3
US Magnesium LLC- Rowley Plant	6.4	1,832.5	288.7	Capitol Reef	3.5	0.02	2.8	1,004.9	6.7	820.9

	*Tons per year: Data is from the 2017 National Emissions Inventory † Additional data from these sources, including recent emissions, projected 2028 emissions, and planned closure, allowed them to be exempt from a 4-factor analysis ††The 2017 NEI does not include the KUC Mine haul truck emissions. UDAQ elaborates on this in section 7.A.2 below

7.A.2 Secondary Screening of Sources

After performing Q/d analysis, UDAQ further narrowed down the list of sources required to undergo the four-factor analysis based on current emissions, projected emissions in 2028, closure and controls put in place after the 2014 base year inventory. As a result of this secondary screening, the following sources were not required to provide a four-factor analysis:

The CCI Paradox Midstream, LLC - Lisbon Natural Gas Processing Plant

The CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant has a complicated regulatory and ownership history which has impacted its emissions performance over the recent past.[131] The combined Q/d (for NO_x, SO_2, and PM_{10}) for the facility was 13.68 for Arches and 20.87 for Canyonlands, both of which are above the Q/d threshold of 6 used to select significant sources of haze impairing pollutants to Utah's CIAs. These high Q/d values largely stemmed from anomalously high SO_2 emissions in 2014 (and 2015) due to issues with the disposal well at the plant. DAQ reviewed Lisbon's most recent five years of data (2017-2021) and re-calculated the Q/d values shown in Table 31 below, all of which fall below UDAQ's Q/d threshold of 6. Of note, recent actual SO_2 emissions have dropped dramatically to between 0.01 and 0.13 percent of the 2014 levels used in the original screening. For this reason, this source was ultimately not required to provide a four-factor analysis. However, UDAQ is continuing to work with this source to evaluate whether reductions in permitted emission limits may be appropriate, particularly for SO_2, given recent actual emissions levels.

[131] In 2009 the plant received a permit modification to lower the SO_2 emissions from 1,593 tons down to 111 tons. The plant requested a reduction in emissions as it had installed both primary and secondary control systems to limit emissions of SO_2. Unfortunately, in 2010 the plant requested a new modification and mistakenly restored the original 1,593 tons of SO_2 emissions without explanation. While that PTE value has been carried forward in more recent permitting actions, actual emissions have never reached the 1,593-ton value. The plant changed ownership in early-2017, which resulted in changes in the operation of the facility and addition of a helium plant in early-2020.

Table 31: Paradox Lisbon Plant Q/d Analysis for nearest CIAs

Year	PM_{10}-PRI	SO_2	NO_x	CIA	Distance (km)	PM_{10}-PRI	SO_2	NO_x	Total Q/d
2017	Plant was not in operation								
2018	45.1	0.1	111.6	Canyonlands	35.8	1.3	0.0	3.1	4.4
2018	45.1	0.1	111.6	Arches	54.6	0.8	0.0	2.0	2.9
2019	Plant was not in operation								
2020	61.9	0.6	126.0	Canyonlands	35.8	1.7	0.0	3.5	5.3
2020	61.9	0.6	126.0	Arches	54.6	1.1	0.0	2.3	3.5
2021	27.8	0.1	181.4	Canyonlands	35.8	0.8	0.0	5.1	5.8
2021	27.8	0.1	181.4	Arches	54.6	0.5	0.0	3.3	3.8

Intermountain Power Service Corporation- Intermountain Generation Station

On September 29, 2006, the Governor of California approved California Senate Bill (SB) 1368, which directed the California Energy Commission to establish a greenhouse gas (GHG) emission performance standard (EPS) for electricity generation and which disallowed load-serving entities in California from entering into long-term financial commitments with electrical corporations unless the generation supplied under the financial commitment complies with that standard. Because approximately 98% of the power generated at the Intermountain Generation Station (IGS) is consumed by customers of California utilities and because the power generated by the IGS's two coal-fired units exceeds California's GHG EPS, the current contract for coal-fired generation, which expires in 2025, will not be renewed for power from those units. Instead, the permittee, Intermountain Power Service Corporation (IPSC), plans to replace the coal-fired units with an EPS-compliant combined-cycle natural gas plant, which will be highly thermally efficient and which will include state-of-the-art emissions controls such as SCR. As a result, regional haze-related pollutants (PM, SO_2, and NO_x) from the IGS are expected to decrease dramatically. Though the coal-fired units are expected to cease operation by mid-2025, Utah is establishing a firm closure date of no later than December 31, 2027, to ensure that the coal-fired units at IGS will not continue to operate beyond the end of the second planning period. This date allows flexibility for closing the plant and the rescinding of the permit and approval order. UDAQ did approach IPSC about the feasibility of improving the efficiency of existing controls, particularly SO_2 scrubbing, at the facility in the three years between mid-2022 and mid-2025, but the company indicated that such improvements are logistically and economically infeasible over such a short time period. Furthermore, the operator's engineering and environmental staff and resources are fully engaged in the process of bringing the replacement gas-fired units online, the successful completion of which will bring about dramatic emissions reductions.

Kennecott Utah Copper LLC- Mine & Copperton Concentrator

The predominant visibility impairing pollutant from the Kennecott Mine and Copperton Concentrator is NO_x, the vast majority of which comes from mine haul trucks and other non-road equipment as shown in Table 32 below. Specifically, this equipment was responsible for 4,376.7

tons (82.5%) of the 5,308.3 tons of combined PM_{10}, SO_2, and NO_x emissions from this facility. Section 209 of the Clean Air Act preempts the State from setting standards for non-road vehicles or engines, leaving UDAQ with few options to control NOx emissions from haul trucks.[132] When non-road emissions are removed from the 2017 inventory for this source, the Q/d drops to 3.9 – i.e., below UDAQ's threshold value of 6. That said, as identified by EPA,[133] the anticipated NO_x+NMHC emissions reduction from replacing a Tier 1 haul truck with a Tier 4 truck is 65.9%, and the NO_x+NMHC emissions reduction from replacing a Tier 2 haul truck with a Tier 4 truck is 42.3%. This gives UDAQ a degree of comfort that emissions from this source will continue to improve over time as older vehicles are replaced.

Additionally, this source recently underwent a thorough BACT analysis as part of the Salt Lake Serious Nonattainment Area PM $_{2.5}$ SIP. As a result, there are no additional controls that can be applied at this time beyond those already included in the SIP as identified in Table 33 in Section 7.A.2 below.

Table 32: 2017 Kennecott Utah Copper LLC – Mine & Concentrator Emissions and Revised Q/d

Source/Distance/Q/d	PM_{10}	SO_2	NO_X	PM_{10}+SO_2+NO_X
Non-Truck Emissions	926.4	0.0	5.2	931.6
Haul Truck (non-road) Emissions	170.0	2.7	4,204.0	4,376.7
Total Emissions	1,096.4	2.7	4,209.2	5,308.3
Distance to nearest CIA (km)	237.2	237.2	237.2	237.2
Revised Q/d without haul truck emissions	3.9	0.0	0.0	3.9

Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment

The coal-fired boilers at the Power Plant Lab Tailings impoundment were decommissioned, and the Approval Order (AO) reflecting this change was updated on February 4, 2020.[134] The February 2020 AO removed any ability for Kennecott to operate coal fired boilers as all the coal-fired boilers were removed from the approved equipment list. The AO summarizes the updates in the project description. Units 1-3 were prohibited to operate under the recently approved $PM_{2.5}$ SIP, and a specific SIP condition set their closure date. Thus, due to that applicable condition, Units 1 – 3 were removed from the permit. Kennecott proposed the removal of Unit 4 from the permit because they planned to decommission the unit. The AO project summarizes that Kennecott made that decision voluntarily, and – based on that decision – Unit 4 was removed from the permit. The AO only lists remaining ancillary equipment. It does not list Units 1-3 or Unit 4 as equipment for the facility and – for this reason – Kennecott does not have

[132] *See* 42 U.S.C. § 7543(e).
[133] Source: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf

[134] This Approval Order can be found at: https://daqpermitting.utah.gov/DocViewer?IntDocID=117327&contentType=application/pdf

approval to operate any coal-fired boilers. Based on this equipment change, UDAQ also rescinded the Title V permit for the facility on February 12, 2020.[135] The vast majority of emissions from this facility were associated with the boilers, and emissions from the remaining equipment (a diesel emergency generator engine, cooling tower, degreasers and two natural gas-fired emergency generators to support the KUC electricity distribution control room) are low enough that this source is below the Q/d threshold for the four-factor analysis. Finally, even if had not been decommissioned, this source recently underwent a thorough BACT analysis for the $PM_{2.5}$ SIP, which resulted in the inclusion of fuel-switching to natural gas and an SCR-derived NO_x rate-based emission limit for Unit 4 in SIP Section IX.H as summarized in Table 33 below. For these reasons, this source was not required to provide a four-factor analysis for the round 2 regional haze SIP.

Table 33: Existing Controls in Utah's SIP for Screened Sources

Company	Facility	Applicable Units	Control Type	Limits	Implementation Date	SIP Reference	Last Revision	EPA Approval	Part H reference
PacifiCorp	Hunter	1 and 2	PM	Emissions of particulate (PM) shall not exceed 0.015 lb/MMBtu heat input from each boiler based on a 3-run test average.	No later than January 1, 2019	Regional Haze	June 24, 2019	Pending	H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology
PacifiCorp	Hunter	1 and 2	NO_x	Emissions of NO_x from each boiler shall not exceed 0.26 lb/MMBtu heat input for a 30-day rolling average.	No later than January 1, 2019	Regional Haze	June 24, 2019	Pending	H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology
PacifiCorp	Hunter	3	NO_x	Emissions of NO_x shall not exceed 0.34 lb/MMBtu heat input for a 30- day rolling average.	No later than January 1, 2019	Regional Haze	June 24, 2019	Pending	H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology
PacifiCorp	Huntington	1 and 2	PM	Emissions of particulate (PM) shall not exceed 0.015 lb/MMBtu heat input from each boiler based on a 3-run test average.	No later than January 1, 2019	Regional Haze	June 24, 2019	Pending	H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology
PacifiCorp	Huntington	1 and 2	NO_x	Emissions of NO_x from each boiler shall not exceed 0.26 lb/MMBtu heat input for a 30-day rolling average.	No later than January 1, 2019	Regional Haze	June 24, 2019	Pending	H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology
Kennecott Utah Copper LLC	Bingham Canyon Mine	Diesel-powered ore and waste haul trucks	Mileage	Maximum total mileage per calendar day for diesel-powered ore and waste haul trucks shall not exceed 30,000 miles.	No later than January 1, 2019	PM2.5	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area

[135] See Appendix G for UDAQ's letter rescinding the Title V permit.

Kennecott Utah Copper LLC	Bingham Canyon Mine	In-pit crusher baghouse	$PM_{2.5}$	The In-pit crusher baghouse shall not exceed a $PM_{2.5}$ emission limit of 0.78 lbs/hr(0.007 gr/dscf) $PM_{2.5}$ monitoring shall be performed by stack testing every three years.	No later than January 1, 2019	PM2.5	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Kennecott Utah Copper LLC	Copperton Concentrator	Dryers		Control emissions from the Product Molybdenite Dryers with a scrubber during operation of the dryers.	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Kennecott Utah Copper LLC	Copperton Concentrator	Heaters	NO_x	The remaining heaters shall not operate more than 300 hours per rolling 12-month period unless upgraded so the NO_x emission rate is no greater than 30 ppm.	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Kennecott Utah Copper LLC	Utah Power Plant	4	Fuel	Only natural gas shall only be used as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. Unit #4 may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment.	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Kennecott Utah Copper LLC	Utah Power Plant	4	$PM_{2.5}$	Filterable $PM_{2.5}$ emissions to the atmosphere when burning natural gas shall not exceed 0.004 grains/dscf. Filterable+condensible $PM_{2.5}$ emissions to the atmosphere when burning natural gas shall not exceed 0.03 grains/dscf.	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Kennecott Utah Copper LLC	Utah Power Plant	4	NO_x	NO_x emissions to the atmosphere when burning natural gas shall not exceed 32 lbs/hr or 0.04 lbs/MMBtu	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Kennecott Utah Copper LLC	Utah Power Plant	5	$PM_{2.5}$	$PM_{2.5}$ with duct burning emissions to the atmosphere when burning natural gas shall not exceed 18.8 lbs/hr (filterable + condensible)	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area

Kennecott Utah Copper LLC	Utah Power Plant	5	VOC	VOC emissions to the atmosphere shall not exceed 2.0 ppmdv	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Chevron Products Co.	Salt Lake Refinery	Source-wide	PM_{10}	Combined emissions of PM_{10} shall not exceed 0.715 tons per day (tpd).	No later than January 1, 2019	PM_{10}	December 2, 2020	Pending	H.2 Source Specific Emission Limitations in Salt Lake County PM_{10} Nonattainment/ Maintenance Area
Chevron Products Co.	Salt Lake Refinery	Source-wide	NO_x	Combined emissions of NO_x shall not exceed 2.1 tons per day (tpd) and 766.5 tons per rolling 12-month period.	No later than January 1, 2019	PM_{10}	December 2, 2020	Pending	H.2 Source Specific Emission Limitations in Salt Lake County PM_{10} Nonattainment/ Maintenance Area
Chevron Products Co.	Salt Lake Refinery	Source-wide	SO_2	Combined emissions of SO_2 shall not exceed 1.05 tons per day (tpd) and 383.3 tons per rolling 12-month period.	No later than January 1, 2019	PM_{10}	December 2, 2020	Pending	H.2 Source Specific Emission Limitations in Salt Lake County PM_{10} Nonattainment/ Maintenance Area
Chevron Products Co.	Salt Lake Refinery	Source-wide	$PM_{2.5}$	Combined emissions of $PM_{2.5}$ (filterable+condensable) shall not exceed 0.305 tons per day (tpd) and 110 tons per rolling 12-month period.	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Chevron Products Co.	Salt Lake Refinery	Source-wide	NO_x	Combined emissions of NO_x shall not exceed 2.1 tons per day (tpd) and 766.5 tons per rolling 12-month period.	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Chevron Products Co.	Salt Lake Refinery	Source-wide	SO_2	Combined emissions of SO_2 shall not exceed 1.05 tons per day (tpd) and 383.3 tons per rolling 12-month period.	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Chevron Products Co.	Salt Lake Refinery	Engine K35001	NO_x	Emissions of NO_x from each rich-burn compressor engine shall not exceed 236 NO_x in ppmvd @ 0% O_2	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Chevron Products Co.	Salt Lake Refinery	Engine K35002	NO_x	Emissions of NO_x from each rich-burn compressor engine shall not exceed 208 NO_x in ppmvd @ 0% O_2	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area
Chevron Products Co.	Salt Lake Refinery	Engine K35003	NO_x	Emissions of NO_x from each rich-burn compressor engine shall not exceed 230 NO_x in ppmvd @ 0% O_2	No later than January 1, 2019	$PM_{2.5}$	December 2, 2020	Pending	H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area

Chevron Products Co.	Salt Lake Refinery	External combustion process equipment	PM_{10}	Combined emissions of filterable PM_{10} from all external combustion process equipment shall be no greater than 0.234 tons per day.	No later than January 1, 2019	PM_{10}	December 2, 2020	Pending	H.4 Interim Emission Limits and Operating Practices

7.A.3 Weighted Emissions Potential Analysis of Sources in Utah and Neighboring States

WRAP released a Weighted Emissions Potential (WEP) analysis after UDAQ chose sources to submit a four-factor analysis. The WEP is obtained by overlaying extinction weighted residence time (EWRT) results with 2028OTBa2 emissions of light extinction precursors and shows which sources have the highest potential to impact visibility in CIAs. Table 34 and Table 35 list the point sources with the top ten WEP values for Utah CIAs for nitrate and sulfate, respectively, and summarize whether those sources were captured by Utah's initial Q/d screen and whether they were ultimately required to submit a four-factor analysis. As can be seen, UDAQ's initial Q/d screen captured most of the point sources with the highest-ranking WEP values at Utah CIAs. For those sources that were ultimately excluded from submitting a four-factor analysis, the tables provide notes as to the rationale for the exclusion, including plant closures, recent BACT analysis/controls, revised emission inventories, and the predominance of emissions from sources that states are largely preempted from controlling (e.g., non-road). The tables also include information regarding the status of non-Utah point sources with high-ranking WEP values, where available.

Tables 36 and 37 list Utah point sources that were among the top ten WEP values in the CIAs of neighboring states for nitrate and sulfate, respectively. Again, the tables show that UDAQ's initial and secondary screening largely succeeded in identifying the sources with the potential to impact CIAs, while excluding some sources that were already well-controlled, closed/closing, or that have few options for state-level controls.

<u>Tesoro and Chevron Refineries</u>

UDAQ's original Q/d screening using 2014 NEI data yielded values below 6 for the Chevron and Tesoro facilities. At EPA's request, UDAQ re-calculated the Q/d thresholds of its major sources using 2017 NEI data to ensure that additional sources did not exceed a Q/d of 6 and confirmed that no additional sources would be screened-in using the newer data. Specifically, neither the Chevron or Tesoro refineries had a revised Q/d of 6 or greater. Here it should be noted that UDAQ chose a more stringent Q/d threshold of 6 rather than the Q/d value of 10 recommended by WRAP.

However, both sources had high-ranking weighted emissions potential values for sulfate or nitrate and various in-state and out-of-state CIAs, Specifically, Chevron ranked 9th for nitrate at BRCA1 with a % of total point WEP of 1.4%. Chevron had no high-ranking sulfate impacts. Tesoro ranked 10th at BRCA1 for nitrate at BRCA1 (0.9%) and had the following rankings and % values for sulfate:

- BRCA1: Rank 8 (2.6%)
- CAPI1: Rank 8 (1.6%)
- BRID1: Rank 8 (3.9%)
- YELL2: Rank 8 (3.4%)
- CRMO1: Rank 6 (2.7%)
- SAWT1: Rank 8 (2.7%)

Though “Top 10” ranked, these WEP values represented a relatively small percentage of total point WEP at each CIA, as indicated above.

In addition, the 2019 Guidance states that it "may be reasonable for a state not to select an effectively controlled source" (page 22) and that "the statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress" (See 2019 EPA Guidance at 23). Both Chevron and Tesoro recently underwent a thorough BACT analysis for the Serious Area $PM_{2.5}$ Salt Lake Nonattainment Area SIP that resulted in additional controls and limits being added to SIP Section IX.H. Specifically, Tesoro installed a wet gas scrubber unit to control SO_2 emissions and is now subject to a source-wide annual SO_2 limit of 300 tons per year. For comparison, WRAP’s WEP analyses used a 2028OTBa2 projection of 708.3 tons. Tesoro’s actual SO_2 emissions for 2019-2021 since the installation of new controls ranged between 22 and 23 tons per year. As a result, the sulfate WEP values for this source – which were already a tiny fraction of total point source sulfate WEP – are not representative of either the enforceable limits or the recent actuals for this facility. Please refer to section 7.A.2 to review the existing controls resulting from the recent $PM_{2.5}$ and PM_{10} SIP revisions for Chevron and Tesoro which include both source-wide and equipment limits for NO_x, SO_2, PM_{10}, and $PM_{2.5}$. Please refer to section 6.A.10 to review the projected emissions reductions resulting from Tesoro's existing controls.

Table 34: Nitrate Point Source WEP Rank for Utah CIAs

Utah CIA	Rank	Facility Name	Source State	2028 OTB NO_x (tons)	Distance (meters)	NO_x Q/d	WEP_NO_3 (% of total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
BRCA1	1	PacifiCorp-Hunter Power Plant	UT	10,001.2	198,466.7	50.4	109,484.1 (18.6%)	YES	YES	
BRCA1	2	PacifiCorp-Huntington Power Plant	UT	6,091.4	216,464.4	28.1	61,138.6 (10.4%)	YES	YES	
BRCA1	3	Kennecott Utah Copper LLC- Mine & Copperton Concentrator	UT	4,199.6	329,072.0	12.8	52,048.8 (8.8%)	YES	NO	BACT for $PM_{2.5}$ Serious SIP; majority of NO_x emissions from non-road sources

Utah CIA	Rank	Facility Name	Source State	2028 OTB NO_x (tons)	Distance (meters)	NO_x Q/d	WEP_NO_3 (% of total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
BRCA1	4	Graymont Western US Incorporated-Cricket Mountain Plant	UT	916.5	155,620.0	5.9	34,304.4 (5.8%)	YES	YES	
BRCA1	5	Ash Grove Cement Company-Leamington Cement Plant	UT	845.5	214,929.5	3.9	30,091.0 (5.1%)	YES	YES	
BRCA1	6	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	1,157.5	342,148.6	3.4	20,954.3 (3.6%)	YES	NO	Power plant closed in 2020
BRCA1	7	Salt Lake City Intl	UT	784.0	350,666.3	2.2	17,677.6 (3.0%)	NO	NO	Q/d <6; majority of NO_x emissions from non-road sources (aircraft take-offs and landings)
BRCA1	8	US Magnesium LLC- Rowley Plant	UT	1,052.1	367,453.2	2.9	10,062.0 (1.7%)	YES	YES	
BRCA1	9	Chevron Products Co - Salt Lake Refinery	UT	375.6	355,251.0	1.1	8,359.5 (1.4%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
BRCA1	10	Tesoro Refining & Marketing Company LLC	UT	358.1	351,572.8	1.0	8,053.0 (0.9%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
CANY1	1	PacifiCorp-Hunter Power Plant	UT	10,001.2	130,681.1	76.5	128,112.8 (13.9%)	YES	YES	
CANY1	2	PacifiCorp-Huntington Power Plant	UT	6,091.4	148,607.2	41.0	68,616.5 (7.4%)	YES	YES	
CANY1	3	Bonanza	TR	5,721.7	185,722.9	30.8	59,301.8 (6.4%)	NA	NA	Likely closure in 2030 due to settlement
CANY1	4	PNM - San Juan Generating Station	NM	7,390.8	219,591.9	33.7	47,113.4 (5.1%)	NA	NA	Subject to four-factor analysis in NM's draft SIP. PNM has announced plant closure in 2022

Utah CIA	Rank	Facility Name	Source State	2028 OTB NO_x (tons)	Distance (meters)	NO_x Q/d	WEP_NO_3 (% of total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
CANY1	5	Kennecott Utah Copper LLC- Mine & Copperton Concentrator	UT	4,199.6	307,168.4	13.7	45,956.2 (5.0%)	YES	NO	BACT for $PM_{2.5}$ Serious SIP; majority of NO_x emissions from non-road sources
CANY1	6	Four Corners Power Plant	TR	4,060.4	228,638.6	17.8	24,859.3 (2.7%)	NA	NA	APS has announced plant closure in 2031
CANY1	7	Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility	UT	442.2	129,762.3	3.4	22,940.9 (2.5%)	YES	YES	
CANY1	8	Chaco Gas Plant	NM	2,053.4	264,690.7	7.8	14,056.2 (1.5%)	NA	NA	Not subject to four-factor analysis in NM's proposed SIP
CANY1	9	CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant	UT	201.9	57,532.7	3.5	12,076.0 (1.3%)	YES	NO	2018 emissions Q/d <6
CANY1	10	RED ROCK GATHERING- PREMIER BAR X C.S.	CO	73.3	118,289.1	0.6	11,567.0 (1.3%)	NA	NA	Not subject to four-factor analysis in CO's proposed SIP due to low NO_x Q/d
CAPI1	1	PacifiCorp- Hunter Power Plant	UT	10,001.2	98,938.2	101.1	334,329.1 (37.2%)	YES	YES	
CAPI1	2	PacifiCorp- Huntington Power Plant	UT	6,091.4	120,459.7	50.6	167,247.5 (18.6%)	YES	YES	
CAPI1	3	Kennecott Utah Copper LLC- Mine & Copperton Concentrator	UT	4,199.6	263,195.8	16.0	42,259.0 (4.7%)	YES	NO	BACT for $PM_{2.5}$ Serious SIP; majority of NO_x emissions from non-road sources
CAPI1	4	Graymont Western US Incorporated- Cricket Mountain Plant	UT	916.5	148,543.7	6.2	26,049.6 (2.9%)	YES	YES	

Utah CIA	Rank	Facility Name	Source State	2028 OTB NO_x (tons)	Distance (meters)	NO_x Q/d	WEP_NO_3 (% of total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
CAPI1	5	Ash Grove Cement Company- Leamington Cement Plant	UT	845.5	159,501.2	5.3	24,633.4 (2.7%)	YES	YES	
CAPI1	6	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	1,157.5	275,718.8	4.2	13,860.1 (1.5%)	YES	NO	Power plant closed in 2020
CAPI1	7	US Magnesium LLC- Rowley Plant	UT	1,052.1	313,659.3	3.4	10,218.3 (1.1%)	YES	YES	
CAPI1	8	Bonanza	TR	5,721.7	261,713.3	21.9	9,450.1 (1.1%)	NA	NA	Likely closure in 2030 due to settlement
CAPI1	9	Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility	UT	442.2	158,414.3	2.8	8,764.7 (1.0%)	YES	YES	
CAPI1	10	Salt Lake City Intl	UT	784.0	280,646.7	2.8	7,264.8 (0.8%)	NO	NO	Q/d <6; majority of NO_x emissions from non-road sources (aircraft take-offs and landings)
ZICA1	1	St. George City Power- Red Rock Power Generation Station	UT	34.3	38,429.0	0.9	13,108.2 (5.3%)	NO	NO	Q/d <6
ZICA1	2	PacifiCorp- Hunter Power Plant	UT	10,001.2	285,805.3	35.0	12,364.2 (5.0%)	YES	YES	
ZICA1	3	McCarran Intl	NV	2,430.2	218,239.9	11.1	9,235.4 (3.7%)	NA	NA	Majority of NO_x emissions from non-road sources (aircraft take-offs and landings)
ZICA1	4	Kern River Gas Transmission Company- Veyo Compressor Station	UT	72.7	56,439.3	1.3	9,185.2 (3.7%)	NO	NO	Q/d <6

Utah CIA	Rank	Facility Name	Source State	2028 OTB NO_x (tons)	Distance (meters)	NO_x Q/d	WEP_NO_3 (% of total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
ZICA1	5	Kennecott Utah Copper LLC- Mine & Copperton Concentrator	UT	4,199.6	385,739.6	10.9	7,998.7 (3.2%)	YES	NO	BACT for $PM_{2.5}$ Serious SIP; majority of NO_x emissions from non-road sources
ZICA1	6	Pg&E Topock Compressor Station	CA	968.8	300,092.2	3.2	7,620.0 (3.1%)	NA	NA	Not subject to four-factor analysis in CA's proposed SIP due to low NOx Q/d
ZICA1	7	Millcreek Power	UT	19.4	38,438.7	0.5	7,402.2 (3.0%)	NO	NO	Q/d <6
ZICA1	8	PacifiCorp-Huntington Power Plant	UT	6,091.4	300,744.4	20.3	7,156.5 (2.9%)	YES	YES	
ZICA1	9	Lhoist North America and Granite Const. (Apex)	NV	1,361.8	181,728.8	7.5	7,041.9 (2.8%)	NA	NA	NV's proposed SIP requires SNCR on Kilns 1, 3, & 4 as well as LNB on Kiln 1. Kilns 3 & 4 have existing LNBs.
ZICA1	10	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	1,157.5	398,524.3	2.9	6,609.7 (2.7%)	YES	NO	Power plant closed in 2020

Table 35: Sulfate Point Source WEP Rank for Utah CIAs

Utah CIA	Rank	Facility Name	Source State	2028 OTB SO2 (tons)	Distance (meters)	SO2 Q/d	WEP_SO_4 (% of Total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
BRCA1	1	CHEMICAL LIME NELSON PLANT	AZ	2,040.6	253,654.7	8.0	43,684.7 (21.8%)	NA	NA	Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
BRCA1	2	PacifiCorp-Hunter Power Plant	UT	3,498.2	198,466.7	17.6	22,430.8 (11.2%)	YES	YES	

Utah CIA	Rank	Facility Name	Source State	2028 OTB SO2 (tons)	Distance (meters)	SO2 Q/d	WEP_SO$_4$ (% of Total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
BRCA1	3	Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment	UT	2,151.9	342,148.6	6.3	17,191.7 (8.6%)	YES	NO	Power plant closed in 2020
BRCA1	4	PacifiCorp-Huntington Power Plant	UT	2,449.0	216,464.4	11.3	14,397.6 (7.2%)	YES	YES	
BRCA1	5	ASARCO LLC - HAYDEN SMELTER	AZ	3,062.1	527,077.3	5.8	14,391.7 (7.2%)	NA	NA	Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
BRCA1	6	Kennecott Utah Copper LLC-Smelter & Refinery	UT	704.4	342,656.1	2.1	5,618.9 (2.8%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
BRCA1	7	Four Corners Power Plant	TR	2,537.7	341,751.7	7.4	5,413.2 (2.7%)	NA	NA	APS has announced plant closure in 2031
BRCA1	8	Tesoro Refining & Marketing Company LLC	UT	708.3	351,572.8	2.0	5,158.3 (2.6%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
BRCA1	9	TUCSON ELECTRIC POWER CO - SPRINGERVILLE	AZ	6,991.9	455,128.8	15.4	3,654.7 (1.8%)	NA	NA	New SO2 limits for units 1 & 2 included in AZ's proposed SIP
BRCA1	10	Phoenix Sky Harbor Intl	AZ	275.1	463,195.4	0.6	3,615.9 (1.8%)	NA	NA	Majority of NO_x emissions from non-road sources (aircraft take-offs and landings)
CANY1	1	PacifiCorp-Hunter Power Plant	UT	3,498.2	130,681.1	26.8	78,098.2 (19.1%)	YES	YES	
CANY1	2	PacifiCorp-Huntington Power Plant	UT	2,449.0	148,607.2	16.5	48,079.5 (11.8%)	YES	YES	
CANY1	3	CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant	UT	534.9	57,532.7	9.3	39,468.2 (9.7%)	YES	NO	2018 emissions Q/d <6
CANY1	4	Four Corners Power Plant	TR	2,537.7	228,638.6	11.1	32,557.0 (8.0%)	NA	NA	APS has announced plant closure in 2031

Utah CIA	Rank	Facility Name	Source State	2028 OTB SO2 (tons)	Distance (meters)	SO2 Q/d	WEP_SO$_4$ (% of Total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
CANY1	5	Sunnyside Cogeneration Associates-Sunnyside Cogeneration Facility	UT	460.8	129,762.3	3.6	25,602.8 (6.3%)	YES	YES	
CANY1	6	Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment	UT	2,151.9	317,050.4	6.8	21,266.8 (5.2%)	YES	NO	Power plant closed in 2020
CANY1	7	TUCSON ELECTRIC POWER CO - SPRINGERVILLE	AZ	6,991.9	463,072.9	15.1	13,923.7 (3.4%)	NA	NA	New SO_2 limits for units 1 & 2 included in AZ's proposed SIP
CANY1	8	CHEMICAL LIME NELSON PLANT	AZ	2,040.6	448,519.3	4.6	13,409.0 (3.3%)	NA	NA	Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
CANY1	9	Bonanza	TR	1,281.3	185,722.9	6.9	11,908.4 (2.9%)	NA	NA	Likely closure in 2030 due to settlement
CANY1	10	PNM - San Juan Generating Station	NM	823.1	219,591.9	3.7	10,995.1 (2.7%)	NA	NA	Subject to four-factor analysis in NM's draft SIP. PNM has announced plant closure in 2022
CAPI1	1	PacifiCorp-Hunter Power Plant	UT	3,498.2	98,938.2	35.4	138,922.3 (34.7%)	YES	YES	
CAPI1	2	PacifiCorp-Huntington Power Plant	UT	2,449.0	120,459.7	20.3	79,880.4 (20.0%)	YES	YES	
CAPI1	3	Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment	UT	2,151.9	275,718.8	7.8	31,599.4 (7.9%)	YES	NO	Power plant closed in 2020
CAPI1	4	CHEMICAL LIME NELSON PLANT	AZ	2,040.6	356,269.4	5.7	25,448.1 (6.4%)	NA	NA	Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls

Utah CIA	Rank	Facility Name	Source State	2028 OTB SO2 (tons)	Distance (meters)	SO2 Q/d	WEP_SO_4 (% of Total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
CAPI1	5	Sunnyside Cogeneration Associates-Sunnyside Cogeneration Facility	UT	460.8	158,414.3	2.9	10,823.1 (2.7%)	YES	YES	
CAPI1	6	ASARCO LLC - HAYDEN SMELTER	AZ	3,062.1	589,323.9	5.2	10,351.8 (2.6%)	NA	NA	Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
CAPI1	7	Kennecott Utah Copper LLC-Smelter & Refinery	UT	704.4	277,921.4	2.5	10,261.2 (2.6%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
CAPI1	8	Tesoro Refining & Marketing Company LLC	UT	708.3	280,166.8	2.5	6,278.1 (1.6%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
CAPI1	9	NORTH VALMY GENERATING STATION	NV	2,277.3	574,890.7	4.0	5,620.2 (1.4%)	NA	NA	NV's proposed SIP includes a federally enforceable closure date of 12/31/28
CAPI1	10	Bonanza	TR	1,281.3	261,713.3	4.9	4,809.0 (1.2%)	NA	NA	Likely closure in 2030 due to settlement
ZICA1	1	CHEMICAL LIME NELSON PLANT	AZ	2,040.6	186,619.3	10.9	38,687.4 (24.8%)	NA	NA	Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
ZICA1	2	Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment	UT	2,151.9	398,524.3	5.4	9,186.4 (5.9%)	YES	NO	Power plant closed in 2020
ZICA1	3	ASARCO LLC - HAYDEN SMELTER	AZ	3,062.1	512,466.4	6.0	6,672.2 (4.3%)	NA	NA	Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls

Utah CIA	Rank	Facility Name	Source State	2028 OTB SO2 (tons)	Distance (meters)	SO2 Q/d	WEP_SO₄ (% of Total)	Selected in Utah Q/d Screen? (Y/N)	UT Four-Factor Analysis? (Y/N)	Notes
ZICA1	4	McCarran Intl	NV	265.3	218,239.9	1.2	4,713.6 (3.0%)	NA	NA	Majority of NO_x emissions from non-road sources (aircraft take-offs and landings)
ZICA1	5	PacifiCorp-Hunter Power Plant	UT	3,498.2	285,805.3	12.2	4,557.8 (2.9%)	YES	YES	
ZICA1	6	Phoenix Sky Harbor Intl	AZ	275.1	428,694.4	0.6	4,554.6 (2.9%)	NA	NA	Majority of NO_x emissions from non-road sources (aircraft take-offs and landings)
ZICA1	7	California Portland Cement Co.	CA	1,445.5	520,498.4	2.8	4,038.8 (2.6%)	NA	NA	Not subject to four-factor analysis in CA's proposed SIP due to AB 617
ZICA1	8	Republic Services Sunrise	NV	209.5	201,737.4	1.0	4,025.8 (2.6%)	NA	NA	Not subject to four-factor analysis in NV's proposed SIP due to low Q/d
ZICA1	9	TUCSON ELECTRIC POWER CO - SPRINGERVILLE	AZ	6,991.9	480,561.1	14.5	3,447.7 (2.2%)	NA	NA	New SO2 limits for units 1 & 2 included in AZ's proposed SIP
ZICA1	10	PacifiCorp-Huntington Power Plant	UT	2,449.0	300,744.4	8.1	3,032.3 (1.9%)	YES	YES	

Table 36: Nitrate Utah Point Source WEP Rank for Non-Utah CIAs

CIA State	CIA	Rank	Facility Name	Source State	2028 OTB NO_x (tons)	Distance (meters)	NO_x Q/d	WEP_NO₃ (% of total)	Selected in Utah Q/d Screen? (Y/N)	Included in Four-Factor Analysis? (Y/N)	Notes
WY	BRID1	5	Kennecott Utah Copper LLC- Mine & Copperton Concentrator	UT	4,199.6	328,062.1	12.8	23,190.1 (3.9%)	YES	NO	BACT for $PM_{2.5}$ Serious SIP; majority of NO_x emissions from non-road sources

CIA State	CIA	Rank	Facility Name	Source State	2028 OTB NO_x (tons)	Distance (meters)	NO_x Q/d	WEP_NO_3 (% of total)	Selected in Utah Q/d Screen? (Y/N)	Included in Four-Factor Analysis? (Y/N)	Notes
WY	YELL2	9	Kennecott Utah Copper LLC- Mine & Copperton Concentrator	UT	4,199.6	461,954.1	9.1	4,042.4 (1.8%)	YES	NO	BACT for $PM_{2.5}$ Serious SIP; majority of NO_X emissions from non-road sources
WY	YELL2	10	Salt Lake City Intl	UT	784.0	437,939.4	1.8	3,887.0 (1.7%)	NO	NO	Q/d <6; majority of NO_X emissions from non-road sources (aircraft take-offs and landings)
ID	CRMO1	10	Kennecott Utah Copper LLC- Mine & Copperton Concentrator	UT	4,199.6	338,486.4	12.4	22,912.5 (2.5%)	YES	NO	BACT for $PM_{2.5}$ Serious SIP; majority of NO_X emissions from non-road sources

Table 37: Sulfate Utah Point Source WEP Rank for Non-Utah CIAs

CIA State	CIA	Rank	Facility Name	Source State	2028 OTB SO_2 (tons)	Distance (meters)	SO_2 Q/d	WEP_SO_4 (% of total)	Selected in Utah Q/d Screen? (Y/N)	Included in Four-Factor Analysis? (Y/N)	Notes
CO	MEVE1	6	CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant	UT	534.9	126,687.8	4.2	22,144.4 (1.3%)	YES	NO	2018 emissions Q/d <6
CO	MEVE1	9	PacifiCorp-Hunter Power Plant	UT	3,498.2	310,434.6	11.3	11,845.4 (0.7%)	YES	YES	
CO	WEMI1	3	CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant	UT	534.9	140,388.0	3.8	24,308.8 (3.8%)	YES	NO	2018 emissions Q/d <6
CO	WEMI1	6	PacifiCorp-Hunter Power Plant	UT	3,498.2	326,019.1	10.7	12,361.1 (1.9%)	YES	YES	

CIA State	CIA	Rank	Facility Name	Source State	2028 OTB SO_2 (tons)	Distance (meters)	SO_2 Q/d	WEP_SO_4 (% of total)	Selected in Utah Q/d Screen? (Y/N)	Included in Four-Factor Analysis? (Y/N)	Notes
WY	BRID1	5	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	2,151.9	317,383.8	6.8	53,003.7 (6.3%)	YES	NO	Power plant closed in 2020
WY	BRID1	8	Tesoro Refining & Marketing Company LLC	UT	708.3	299,746.7	2.4	32,334.3 (3.9%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
WY	NOAB1	8	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	2,151.9	499,395.1	4.3	15,792.1 (2.2%)	YES	NO	Power plant closed in 2020
WY	YELL2	2	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	2,151.9	449,396.5	4.8	23,791.3 (7.4%)	YES	NO	Power plant closed in 2020
WY	YELL2	8	Tesoro Refining & Marketing Company LLC	UT	708.3	435,882.7	1.6	10,963.7 (3.4%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
ID	CRMO1	4	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	2,151.9	326,319.5	6.6	18,525.9 (6.8%)	YES	NO	Power plant closed in 2020
ID	CRMO1	6	Tesoro Refining & Marketing Company LLC	UT	708.3	325,079.4	2.2	7,431.8 (2.7%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
ID	CRMO1	10	Kennecott Utah Copper LLC- Smelter & Refinery	UT	704.4	323,667.2	2.2	6,113.6 (2.2%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
ID	SAWT1	4	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	2,151.9	446,448.0	4.8	6,827.9 (5.4%)	YES	NO	Power plant closed in 2020
ID	SAWT1	8	Tesoro Refining & Marketing Company LLC	UT	708.3	448,276.9	1.6	3,373.8 (2.7%)	NO	NO	Q/d <6; BACT for +$PM_{2.5}$ Serious SIP

CIA State	CIA	Rank	Facility Name	Source State	2028 OTB SO_2 (tons)	Distance (meters)	SO_2 Q/d	WEP_SO_4 (% of total)	Selected in Utah Q/d Screen? (Y/N)	Included in Four-Factor Analysis? (Y/N)	Notes
ID	SAWT1	10	Kennecott Utah Copper LLC- Smelter & Refinery	UT	704.4	442,899.3	1.6	2,252.8 (1.8%)	NO	NO	Q/d <6; BACT for $PM_{2.5}$ Serious SIP
NV	JARB1	10	Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	UT	2,151.9	304,126.8	7.1	5,105.3 (1.4%)	YES	NO	Power plant closed in 2020
AZ	GRCA2	10	PacifiCorp-Hunter Power Plant	UT	3,498.2	363,743.3	9.6	2,321.3 (0.6%)	YES	YES	

7.A.4 Other Sources

The foregoing Q/d analysis, secondary screening, and WEP analysis sections were used to help identify point sources with potential impacts at Utah and non-Utah CIAs. However, the emissions inventories detailed in section 5.A and the WRAP photochemical source apportionment results provided in section 6.A suggest that non-point sources in Utah may also impact visibility in CIAs. This section discusses the potential impacts of and state of emissions controls for non-point sources in Utah.

Oil and Gas

Utah oil and gas sources are spread over a very large area making a traditional Q/d analysis problematic. Furthermore, in light of updated inventory findings discussed below, UDAQ does not consider the WRAP oil and gas inventories to be adequate for any type of Q/d emissions analysis, derived or otherwise. That said, UDAQ acknowledges that oil and gas sector emissions may affect visibility in CIAs.

Most of Utah's oil and gas sector emissions occur in the Uinta Basin (UB), where considerable work has already been done to address this sector's contribution to wintertime ozone pollution. The UB, located in northeast Utah, contains the majority of oil and gas extraction in Utah. The UB has been found to have high levels of ozone during the winter months. This phenomenon is associated with the geological basin, cold temperature inversion, and snow cover albedo in the presence of VOCs and NO_x. The majority of emissions for the ozone precursors of VOC and NO_x come primarily from the oil and gas exploration and production in the area, not other urban or mobile sources. Since the discovery of these high ozone emissions, Utah has acted to control the oil and gas sources in the UB and the rest of the state. However, the jurisdictional complexity of the UB has led to inconsistency between state-controlled sources and EPA-controlled sources on Indian Country. Emission inventories show that about 80% of the emissions are under EPA regulatory control. The 2017 oil and gas emission inventory compared to the total emission inventory for the UB accounts for about 97% of the total VOC emissions and 68% of the total NO_x emissions. The 2017 oil and gas emission inventory showed that 80% of emissions in the UB result from areas under EPA control. Therefore, the state of Utah can only address about 20% of the ozone-forming precursors VOC and NO_x and cannot address air quality issues on their own in the UB. Over the past several years, UDAQ has proposed and adopted a series of statewide rules specific to oil and gas operations found in Utah's state administrative rules R301-500 to 511. Though these rules have been focused on controlling VOC emissions, there is also a state-specific rule for natural gas-powered engines associated with oil and gas production. Since the rule was put in place in 2018, several sources have provided engine stack test data that have led UDAQ, EPA, and the Tribes to initiate further research and compliance studies on engines in the Basin, with a focus on two-stroke smaller horsepower engines that power pump jacks associated with oil-producing wells. The data collected have indicated lower values for NO_x emissions than what was reported in the 2017 oil and gas emission inventory for these engines, yet much higher emissions of VOCs. UDAQ will be evaluating this data and will be evaluating future rulemaking for engines associated with oil and gas operations that would be statewide. EPA did follow UDAQ's lead and has proposed the Uintah and Ouray Federal Implementation Plan that is similar to Utah's oil and gas rules, and will bring some regulatory consistency to the area. The UDAQ will continue to coordinate with EPA and the Tribe to encourage that rules are consistent across all regulatory jurisdictions, but ultimately any controls under EPA regulatory jurisdiction will be determined by EPA and the Tribe[136].

Mobile

As identified in section 6.A above, mobile source emissions are a leading Utah source for nitrate impacts at all Utah CIAs and in some neighboring states, namely Colorado, Idaho, and Wyoming. Under Section 209 of the Clean Air Act, states are largely preempted from setting standards for on-road and non-road mobile sources. Fortunately, federal emission standards for on-road vehicles and engines as well as non-road equipment are projected to result in dramatic reductions in NO_x and PM emissions in Utah over the second planning period for regional haze. To help guarantee these emissions reductions, the State of Utah has worked with the petroleum refiners that supply the Utah market to ensure that suppliers produce gasoline that meets the Tier 3 sulfur requirement of 30 ppm and not just comply using credits. In addition, Utah has taken measures as part of other air quality programs to ensure that mobile source emissions are well-controlled. For example, Utah has vehicle inspection and maintenance programs in place in Utah, Salt Lake, Davis, Weber, and Cache counties, which accounted for 79.3% of the state's population in 2021[i] and 60.1% of total statewide on-road mobile source OTB2028a2 emissions. These programs also include diesel vehicle inspections which, while not creditable in Utah's various SIP revisions, help reduce NO_x emissions that contribute to nitrate formation and CIA impacts.

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[136] Please refer to sections 5.B and 9.C.2, response 24 for additional information concerning Utah's area sources.

Remaining Anthropogenic

The remaining anthropogenic category of the WRAP photochemical analysis represents non-oil and gas area source emissions, and specifically includes fugitive dust, agriculture, agricultural fire, residential wood combustion, and all remaining nonpoint sources (e.g., residential and commercial stationary source fuel combustion). As shown in section 6.A, the remaining anthropogenic impacts are relatively small for Utah and non-Utah CIAs. That said, these sources are relatively well-controlled as a result of rulemaking associated with other air quality programs in Utah (e.g., the $PM_{2.5}$ SIP BACM review and resulting controls). For example, Utah restricts residential wood burning on so-called mandatory action days when conditions are ripe for secondary formation of particulates. Utah has also adopted an ultra-low NO_x water heater rule that applies statewide and, when fully implemented, will result in a 75% reduction in NO_x emissions from residential and commercial water heating-related natural gas stationary source fuel combustion. Additional Utah area source rules to reduce NO_x and/or PM emissions include those governing hydronic heaters, fugitive dust, and pilot lights.

7.A.5 Environmental Justice Considerations

Environmental Justice (EJ) is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies[137]. Absent further guidance from EPA, UDAQ believes the consideration of EJ is best used in the screening process to ensure sources within disproportionately affected areas are included in the four-factor analysis process. UDAQ has used the EJScreen (version 2.0) tool developed by EPA to analyze the environmental justice indices surrounding the sources selected to conduct four-factor analyses. EJScreen[138]. For the 10 sources originally screened in this implementation period, UDAQ reviewed all pollution and sources as well as socioeconomic indicators (a total of 19 indices) as percentiles calculated by comparing data from census blocks within the state of Utah. UDAQ notes that the RH program does not have the authority to control the following indexes included in this analysis: lead paint, superfund sites, wastewater discharge, RMP facilities, hazardous waste, or underground storage tanks. Percentiles for all indexes were generated for each source's location centered within a 20-mile buffer radius. UDAQ recorded all indexes in the 80th percentiles and above at the state level for the screened sources and offers the following information used to consider the co-benefits of the reasonable progress determinations included in this implementation period. UDAQ was not able to draw significant conclusions from this analysis affecting the reasonable progress determinations made in this SIP revision.

Table 38: Ash Grove Leamington Cement Plant EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile

[137] More information on EJ can be found at: https://www.epa.gov/environmentaljustice

[138] Technical information on EJScreen can be found at: https://www.epa.gov/sites/default/files/2021-04/documents/ejscreen_technical_document.pdf

Pollution and Sources			
No percentiles above 80.			
Socioeconomic Indicators			
Under Age 5	12%	8%	85

Table 39: Graymont Western Cricket Mountain Plant EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
Lead Paint (% Pre-1960 Housing)	0.3	0.17	81
Socioeconomic Indicators			
No percentiles above 80.			

Table 40: PacifiCorp Hunter Power Plant EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
No percentiles above 80.			
Socioeconomic Indicators			
Over Age 64	16%	11%	81

Table 41: PacifiCorp Huntington Power Plant EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
No percentiles above 80.			
Socioeconomic Indicators			
Unemployment Rate	6%	4%	84
Over Age 64	16%	11%	80

Table 42: Sunnyside Cogeneration Power Plant EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
Lead Paint (% Pre-1960 Housing)	0.48	0.17	89
Socioeconomic Indicators			
Low Income	41%	27%	80
Unemployment Rate	8%	4%	89
Over Age 64	17%	11%	83

Table 43: US Magnesium Rowley Plant EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
2017 Air Toxics Respiratory HI	0.62	0.3	98
Wastewater Discharge (toxicity-weighted concentration/m distance)	11	13	88
Socioeconomic Indicators			
No percentiles above 80.			

Table 44: Intermountain Generation Station EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
Lead Paint (% Pre-1960 Housing)	0.29	0.17	81
Socioeconomic Indicators			
No percentiles above 80.			

Table 45: Kennecott Power Plant EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
2017 Air Toxics Cancer Risk* (lifetime risk per million)	24	21	89
2017 Air Toxics Respiratory HI*	0.37	0.3	89
Superfund Proximity (site count/km distance)	0.34	0.18	88
Hazardous Waste Proximity (facility count/km distance)	1.5	0.89	80
Socioeconomic Indicators			
No percentiles above 80.			

Table 46: Kennecott Mine and Copperton Concentrator EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
2017 Air Toxics Cancer Risk* (lifetime risk per million)	24	21	88
2017 Air Toxics Respiratory HI*	0.36	0.3	89
Superfund Proximity (site count/km distance)	0.24	0.18	83
Socioeconomic Indicators			
No percentiles above 80.			

Table 47: Paradox Lisbon Plant EJScreen Findings

Selected Variables	Value	State	
		Avg.	%tile
Pollution and Sources			
Superfund Proximity (site count/km distance)	0.36	0.18	88
Socioeconomic Indicators			
Over Age 64	18%	11%	86

7.B Four-Factor Analyses for Utah Sources[139]

Each source subject to submitting a four-factor analysis in this second planning period submitted a report on the available control technologies for SO_2 and NO_x emission reductions and the application of each technology to that facility. UDAQ notes that none of the sources selected to complete a four-factor analysis are within any nonattainment areas under the NAAQS. The information on available controls should include the analysis of the following four factors when determining the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source[140]

Although not specifically required, the recommended approach was to follow a step-by-step review of possible emission reduction options in a "top-down" fashion similar to EPA's guidelines for reviewing BART or Best Available Retrofit Technology (as found in 70 Fed. Reg. 39,104, 39,108-09 (July 6, 2005)). The steps involved are as follows:

1. Identify all available retrofit control technologies
2. Eliminate technically infeasible control technologies
3. Evaluate the control effectiveness of remaining control technologies
4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. UDAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may

[139] 40 CFR 51.308(f)(2)(i)
[140] *See* 40 C.F.R. § 51.308(f)(2)(i).

have differed from the recommended process, UDAQ makes a note, and provides additional explanation as necessary.

7.B.1 Control Equipment Descriptions

Available NO_x Reduction Strategies and Technologies[141]

The sources selected to provide additional analyses consistent with the four factors listed above-evaluated controls primarily for NO_x emissions reductions. The following represents proven, available NO_x reduction strategies and technologies for four-factor sources. The sources selected to provide additional analyses consistent with the four factors listed above evaluated controls primarily for NO_x emissions reductions.

Fuel switching. Fuel switching is the simplest and potentially the most economical way to reduce NO_x emissions. Fuel-bound NO_x formation is most effectively reduced by switching to a fuel with reduced nitrogen content. No. 6 fuel oil or another residual fuel, having relatively high nitrogen content, can be replaced with No. 2 fuel oil, another distillate oil, or natural gas (which is essentially nitrogen-free) to reduce NO_x emissions.

Flue-gas recirculation (FGR). Flue gas recirculation involves extracting some of the flue gas from the stack and recirculating it with the combustion air supplied to the burners. The process reduces both the oxygen concentration at the burners and the temperature by diluting the combustion air with flue gas. Reductions in NO_x emissions ranging from 30 to 60% have been achieved with this control technology.

Low NO_x burners. Installation of burners especially designed to limit NO_x formation can reduce NO_x emissions by up to 50%. Greater reduction efficiencies can be achieved by combining a low-NO_x burner with FGR—though not additive of each of the reduction efficiencies. Low-NO_x burners are designed to reduce the peak flame temperature by inducing recirculation zones, staging combustion zones, and reducing local oxygen concentrations.

Derating. Some industrial boilers can be derated to produce a reduced quantity of steam or hot water. Derating can be accomplished by reducing the firing rate or by installing a permanent restriction, such as an orifice plate, in the fuel line.

Steam or water injection. Injecting a small amount of water or steam into the immediate vicinity of the flame will lower the flame temperature and reduce the local oxygen concentration. The result is to decrease the formation of thermal and fuel-bound NO_x. Be advised that this process generally lowers the combustion efficiency of the unit by 1 to 2%.

Staged combustion. Either air or fuel injection can be staged, creating either a fuel-rich zone followed by an air-rich zone or an air-rich zone followed by a fuel-rich zone. Staged combustion can be achieved by installing a low-NO_x staged combustion burner, or the furnace can be

[141] More information on emission control strategies can be found at: https://www.epa.gov/sites/default/files/2015-07/documents/chapter_5_emission_control_technologies.pdf

retrofitted for staged combustion. NO_x reductions of more than 40% have been demonstrated with staged combustion.

Fuel reburning. Staged combustion can be achieved through the process of fuel reburning by creating a gas-reburning zone above the primary combustion zone. In the gas-reburning zone, additional natural gas is injected, creating a fuel-rich region where hydrocarbon radicals react with NO_x to form molecular nitrogen. Field evaluations of natural gas reburning (NGR) on several full-scale utility boilers have yielded NO_x reductions ranging from 40 to 75%.

Reduced-oxygen concentration. Decreasing the excess air reduces the oxygen available in the combustion zone and lengthens the flame, resulting in a reduced heat-release rate per unit flame volume. NO_x emissions diminish in an approximately linear fashion with decreasing excess air. However, as excess air falls below a threshold value, combustion efficiency will decrease due to incomplete mixing, and CO emissions will increase. The optimum excess-air value must be determined experimentally and will depend on the fuel and the combustion-system design. A feedback control system can be installed to monitor oxygen or combustibles levels in the flue gas and to adjust the combustion-air flow rate until the desired target is reached. Such a system can reduce NO_x emissions by up to 50%.

Selective catalytic reduction (SCR). SCR is a post-formation NO_x control technology that uses a catalyst to facilitate a chemical reaction between NO_x and ammonia to produce nitrogen and water. An ammonia/air or ammonia/steam mixture is injected into the exhaust gas, which then passes through the catalyst where NO_x is reduced. To optimize the reaction, the temperature of the exhaust gas must be in a certain range when it passes through the catalyst bed. Typically, removal efficiencies greater than 80% can be achieved, regardless of the combustion process or fuel type used. Among its disadvantages, SCR requires additional space for the catalyst and reactor vessel, as well as an ammonia storage, distribution, and injection system. Also, a Risk Management Plan (RMP) in compliance with Federal Accidental Release Prevention rules may have to be prepared and submitted for ammonia storage. Precise control of ammonia injection is critical. An inadequate amount of ammonia can result in unacceptable high NO_x emission rates, whereas excess ammonia can lead to ammonia "slip," or the venting of undesirable ammonia to the atmosphere. As NH_3 is both a visibility impairing air pollutant and a wastewater regulated pollutant, air emissions and water discharges can be impacted. Excess ammonia in the presence of other pollutants still remaining in the flue gas can also form species such as ammonium-sulfate which can create visible plumes downwind of the stack discharge.

Selective non-catalytic reduction (SNCR). Selective non-catalytic NO_x reduction involves injection of a reducing agent—ammonia or urea—into the flue gas. The optimum injection temperature when using ammonia is 1850ºF, at which temperature 60% NO_x removal can be approached. The optimum temperature range is wider when using urea. Below the optimum temperature range, ammonia forms, and above, NO_x emissions actually increase. The success of NO_x removal depends not only on the injection temperature but also on the ability of the agent to mix sufficiently with flue gas.

Available SO_2 Reduction Strategies and Technologies[142]

The following represents proven, available SO_2 reduction strategies and technologies for four-factor sources.

Choice of Fuel. Since sulfur emissions are proportional to the sulfur content of the fuel, an effective means of reducing SO_2 emissions is to burn low-sulfur fuel such as natural gas, low-sulfur oil, or low-sulfur coal. Natural gas has the added advantage of emitting no PM when burned.

Sorbent Injection. Sorbent injection involves adding an alkali compound to the combustion gases for reaction with the SO_2. Typical calcium sorbents include lime and variants of lime. Sodium-based compounds are also used. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. Sorbent injection processes remove 30–60% of sulfur oxide emissions; however, if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers.

Flue Gas Desulfurization (FGD). FGD may be carried out using either of the two basic systems: regenerable or throwaway. Both methods may include wet or dry processes. Currently, more than 90% of utility FGD systems use a wet throwaway system process. Throwaway systems use inexpensive scrubbing mediums that are cheaper to replace than to regenerate. Regenerable systems use expensive sorbents that are recovered by stripping sulfur oxides from the scrubbing medium. These produce useful by-products, including sulfur, sulfuric acid, and gypsum. Regenerable FGDs generally have higher capital costs than throwaway systems but lower waste disposal requirements and costs.

FGD processes can be wet or dry. In wet FGD processes, flue gases are scrubbed in a liquid or liquid/solid slurry of lime or limestone. Wet processes are highly efficient and can achieve SO_2 removal of 90% or more. With dry scrubbing, solid sorbents capture the sulfur oxides. Dry systems have 70–90% sulfur oxide removal efficiencies and often have lower capital and operating costs, lower energy and water requirements, and lower maintenance requirements, in addition to which there is no need to handle sludge. Examples of FGD include:

Dual Alkali Wet Scrubber. Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop.

Spray Dry Absorber. The typical spray dry absorber (SDA) uses lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to

[142] More information on emission control strategies can be found at: https://www.epa.gov/sites/default/files/2015-07/documents/chapter_5_emission_control_technologies.pdf

produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, atomizer, spray chamber, particulate control device, and recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use. SDAs are the commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 95% SO_2 reduction.

Circulating Dry Scrubber. The circulating dry scrubber (CDS) uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the particulate removal system.

Hydrated Ash Reinjection. The hydrated ash reinjection (HAR) process is a modified dry FGD process developed to increase utilization of unreacted lime (CaO) in the CFB ash and any free lime left from the furnace burning process. The hydrated ash reinjection process will further reduce the SO_2 concentration in the flue gas. The actual design of a hydrated ash reinjection system is vendor specific. In a hydrated ash reinjection system, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFB boiler applications, sufficient residual CaO is available in the ash and additional lime is not required.

7.B.2 Existing Controls on Active EGUs

The following tables summarize existing controls on all active coal and gas facilities in Utah. For more detailed information on control compliance schedules from the first implementation period and retirement dates, refer to section 3.A.1.

Table 48: Existing controls on active coal units in Utah

Facility	Unit	Operator	SO_2 Control(s)	NO_x Control(s)
Bonanza	43101	Deseret Generation & Transmission	Wet Limestone	Low NO_x Burner Technology (Dry Bottom only)
Hunter	1	PacifiCorp Energy Generation	Wet Lime FGD	Low NO_x Burner Technology w/ Closed-coupled OFA
Hunter	2	PacifiCorp Energy Generation	Wet Lime FGD	Low NO_x Burner Technology w/ Separated OFA
Hunter	3	PacifiCorp Energy Generation	Wet Lime FGD	Low NO_x Burner Technology w/ Overfire Air
Huntington	1	PacifiCorp Energy Generation	Wet Lime FGD	Low NO_x Burner Technology w/ Closed-coupled OFA
Huntington	2	PacifiCorp Energy Generation	Wet Lime FGD	Low NO_x Burner Technology w/ Separated OFA

Table 49: Existing controls on active gas units in Utah

Facility Name	Unit ID	Owner	NO_x Control(s)
Lake Side Power Plant	CT03	PacifiCorp Energy Generation	Selective Catalytic Reduction
Lake Side Power Plant	CT04	PacifiCorp Energy Generation	Selective Catalytic Reduction
Lake Side Power Plant	CT02	PacifiCorp Energy Generation	Selective Catalytic Reduction
Currant Creek Power Project	CTG1B	PacifiCorp Energy Generation	Selective Catalytic Reduction
Currant Creek Power Project	CTG1A	PacifiCorp Energy Generation	Selective Catalytic Reduction
Nebo Power Station	U1	Utah Associated Municipal Power Systems	Dry Low NO_x Burners Selective Catalytic Reduction
Millcreek Power	MC-1	City of St. George	Dry Low NO_x Burners
Millcreek Power	MC-2	City of St. George	Dry Low NO_x Burners Selective Catalytic Reduction
Gadsby	4	PacifiCorp Energy Generation	Water Injection Selective Catalytic Reduction
West Valley Power Plant	U4	Utah Municipal Power Agency	Water Injection Selective Catalytic Reduction
West Valley Power Plant	U2	Utah Municipal Power Agency	Water Injection Selective Catalytic Reduction
West Valley Power Plant	U3	Utah Municipal Power Agency	Water Injection Selective Catalytic Reduction
Gadsby	5	PacifiCorp Energy Generation	Water Injection Selective Catalytic Reduction
West Valley Power Plant	U5	Utah Municipal Power Agency	Water Injection Selective Catalytic Reduction
Gadsby	6	PacifiCorp Energy Generation	Water Injection Selective Catalytic Reduction
West Valley Power Plant	U1	Utah Municipal Power Agency	Water Injection Selective Catalytic Reduction
Gadsby	2	PacifiCorp Energy Generation	Low NO_x Burner Technology (Dry Bottom only)
Gadsby	1	PacifiCorp Energy Generation	Low NO_x Burner Technology (Dry Bottom only)

7.C Source Consultation

UDAQ has kept regular contact with the sources selected to perform four-factor analyses on their units and offered guidance on developing control cost estimates using EPA's Air Pollution

Control Cost Manual[143] and facility-specific data representing current emissions, projected future emissions, and potential control scenarios. UDAQ received and reviewed each source's initial four-factor analysis and sent an evaluation to each source with recommendations, requests for additional information, and explanations of any issues with calculations or assumptions made by sources in calculations. Refer to Chapter 9 to review detailed information on UDAQ's meetings with the sources. The following sections contain each source's four-factor analysis, UDAQ's evaluation of their initial submittal, and the sources resulting responses and corrections.[144]

7.C.1 Ash Grove Cement Company- Leamington Cement Plant Four-Factor Analysis Summary and Evaluation[145]

Facility Identification

Name: Ash Grove Cement Company
Address: Hwy. 132, Leamington, Utah 84638
Owner/Operator: Ash Grove Cement Company
UTM coordinates: 4,379,850 m Northing, 397,000 m Easting, Zone 12

Facility Process Summary

Ash Grove Cement Company (Ash Grove) operates the Leamington Cement Plant. This plant has been in operation since 1981. At the Leamington cement plant, cement is produced when inorganic raw materials, primarily limestone (quarried on site), are correctly proportioned, ground and mixed, and then fed into a rotating kiln. The kiln alters the materials and recombines them into small stones called cement clinker. The clinker is cooled and ground with gypsum and additional limestone into a fine powdered cement. The final product is stored on site for later shipping. The major sources of air emissions are from the combustion of fuels for the kiln operation, from the kiln, and from the clinker cooling process.

Facility Criteria Air Pollutant Emissions Sources

This source consists of the following emission unit:

- Unit Designation: Kiln 1
  Kiln 1 has the following emission controls installed:
  SNCR for NO_x control; NO_x, CO, Total Hydrocarbons (VOC), and Oxygen (O_2) CEMS on main stack; Mercury (Hg) CEMS or integrated sorbent trap monitoring system on main stack; TSP (PM) Continuous Parametric Monitoring System (CPMS) on main kiln and clinker cooler stack.

143 The EPA Air Pollution Control Cost Manual can be found in at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual
144 Each source's full four-factor analysis submittals, UDAQ's four-factor analysis evaluations, and evaluation responses sent by sources can be found at https://deq.utah.gov/air-quality/regional-haze-in-utah in the "Current Regional Haze Planning" section.
145 Ash Grove's full four-factor analysis submittal can be found in appendix C.1.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008930.pdf

Facility Current Potential to Emit

The current PTE values for Ash Grove, as established by the most recent NSR permit issued to the source (DAQE-AN103030029-19) are as follows:

Table 50: Ash Grove Leamington Cement Plant Current Potential to Emit

Pollutant	Potential to Emit (tons/year)
SO_2	192.50
NO_x	1347.20

Ash Grove's Four-Factor Analysis Conclusion

Ash Grove believes that reasonable progress compliant controls are already in place. Ash Grove's actual NO_x emission level of 1198 tpy is adequate and the Leamington facility does not propose any change to their current limit of 2.8 lbs./ton clinker on a 30-day rolling average basis.

UDAQ Four-Factor Analysis Evaluation[146]

Although some additional information should be supplied by the source regarding SNCR efficiency, the Leamington Cement Plant appears to be adequately controlled at this time for purposes of Second Planning Period.

Ash Grove's Evaluation Response[147]

AGC provided the actual SO_2 emissions rates for the Leamington Plant's main kiln which are lower than their PTE. Lowering SO_2 emissions further would require the addition of aluminum and iron which are not readily available to Ash Grove. The efficiency of the Leamington Plant's SNCR system was designed to be able to achieve 2.8 lb. NO_x/ton clinker on a 30-day rolling average basis, and the plant typically operates in the 2.5-2.6 lb. NO_x/ton clinker range. The system uses an Aqua NH_3 solution as a chemical reagent. Adding additional solution is not feasible as the plant already requires reagent delivery by truck every two days and additional reagent would require the installation of larger nozzles and/or larger storage tanks. The system is also near solution saturation as it currently runs, and additional solution may not increase control efficiency, but rather cause NH_3 to slip from the system and be emitted from the stack. Thus, Ash Grove believes that the current and NO_x limits reflect a reasonable level of safety margin relative to actual emission rates.

[146] UDAQs full evaluation of Ash Grove's four-factor analysis submittal can be found in appendix C.1.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009636.pdf

[147] Ash Grove's full evaluation response can be found in appendix C.1.B or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011724.pdf

UDAQ Response Conclusion

UDAQ accepts the additional information provided by Ash Grove on their emission rate efficiency and agrees that their units are well controlled. Refer to section 8.D.1. for UDAQ's reasonable progress determination for Ash Grove.

7.C.2 Graymont Western US Incorporated- Cricket Mountain Plant Four-Factor Analysis Summary and Evaluation[148]

Facility Identification

Name: Cricket Mountain Plant
Address: 32 Miles Southwest of Delta, Utah; Highway 257
Owner/Operator: Graymont Western US Incorporated
UTM coordinates: 4,311,010 m Northing, 343,100 m Easting, Zone 12

Facility Process Summary

Graymont Western US Inc. (Graymont) operates the Cricket Mountain Lime Plant in Millard County. The Cricket Mountain Lime Plant consists of quarries and a lime processing plant, which includes five (5) rotary lime kilns (Kilns 1 through 5). The rotary kilns are used to convert crushed limestone ore into quicklime. The products produced for resale are lime, limestone, and kiln dust. The kilns operate on pet coke and coal. Sources of emissions at this source include mining, limestone processing, rotary lime kilns, post-kiln lime handling, and truck & loadout facilities.

Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Rotary Lime Kiln #1 rated at 600 tons of lime per 24-hour period with a preheater and baghouse emissions control system (D-85) rated at an exhaust gas flow rate 54,000 scfm and an Air to Cloth (A/C) ratio of 3.26:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #2 rated at 600 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-275) rated at an exhaust gas flow rate of 48,000 scfm and an A/C ratio of 2.9:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #3 rated at 840 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-375) rated at an exhaust gas flow rate of 55,000 scfm and a A/C ratio of 2.49:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #4 rated at 1266 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-485) rated at an exhaust gas flow

[148] Graymont's full four-factor analysis submittal for the Cricket Mountain Plant can be found in appendix C.2.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008924.pdf

rate of 100,000 scfm and an A/C ratio of 5:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA

- Rotary Lime Kiln #5 rated at 1400 tons of lime per 24-hour period with a preheater and baghouse emissions control system (D-585) rated at an exhaust gas flow rate of 103,000 scfm and an A/C ratio of 3.5:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA

Facility Current Potential to Emit

The current PTE values for Source, as established by the most recent NSR permit issued to the source (DAQE-AN103130044-21) are as follows:

Table 51: Current Potential to Emit - Graymont

Pollutant	Potential to Emit (tons/year)
SO_2	760.29
NO_x	3,883.85

Graymont Four-Factor Analysis Conclusion

The facility currently uses low NO_x burners in its five kilns to minimize NO_x emissions. The use of low NO_x burners is a commonly applied technology in current BACT determinations for new rotary preheater lime kilns today. The application of SCR has never been attempted on a lime kiln. SNCR has only one RBLC entry documenting implementation on a lime kiln. The use of these controls does not represent a cost-effective control technology given the limited expected improvements to NO_x emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton NO_x removed. Therefore, the emissions for the 2028 on-the-books modeling scenario are expected to be the same as those used in the "control scenario" for the Graymont Cricket Mountain facility.

UDAQ Four-Factor Analysis Evaluation[149]

UDAQ disagrees with several points of Graymont's analysis. Aside from the lack of SO_2 analysis, UDAQ found several errors in the Graymont NO_x analysis which must be corrected.

1. Two additional control technologies were identified by DAQ as potential ways of reducing NO_x emissions: fuel switching and alternative production techniques. The Graymont Cricket Mountain Plant is fueled by coal – alternative fuels should be investigated. Secondly, the kilns at this facility are long horizontal rotary preheater/precalciner style kilns. Other types of kiln such as vertical lime kilns should also be investigated.
2. Graymont has claimed that SNCR is not technically feasible for installation on rotary preheater kilns. However, that is not accurate as there have been other SNCR retrofits

[149] UDAQ's full evaluation of Graymont's four-factor analysis submittal can be found in appendix C.2.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009634.pdf

done at preheater rotary lime kilns. Those lime kilns include the Lhoist North America O'Neal Plant in Alabama, the Unimin Corporation lime plant in Calera, Alabama, and the rotary lime kilns of the Lhoist North America Nelson Lime Plant in Arizona, as well as the Mississippi Lime Company plant in Illinois (specifically mentioned by Graymont as the only source listed on the RBLC).

3. A NO_x reduction of 20% for SNCR is too low for use in the analysis, given that Graymont itself quoted the average NO_x removal at cement kilns with SNCR was 40%, with the range of NO_x removal efficiency between 35%-58%. At a minimum, Graymont should have evaluated the use of SNCR at 35% removal efficiency rather than merely 20%.
4. The current bank prime rate is 3.25% and not 4.75% as stated by Graymont. The economic analysis must be recalculated using the correct interest rate.
5. The cost of an air preheater was included – which appears to be a mistake based on an error (a typographical misprint) found in EPA's SNCR control cost spreadsheets. In one place the spreadsheet uses a value of 3.0 lb. SO_2/ton coal while in another the value is erroneously listed as 0.3 lb. SO_2/ton coal. Graymont apparently included the cost of the air preheater when burning coal which does not require such equipment as part of an SNCR installation.

Although DAQ has not fully evaluated these deficiencies, it has analyzed how Graymont's cost evaluation would change if the correct bank prime interest rate were used, if the cost of the air preheater were not included, and if the removal efficiency of the SNCR were increased to a minimum of 35%. To reflect the increased cost of a more efficient SNCR than that proposed by Graymont, the direct annual costs (energy, cost of ammonia, etc.) were doubled as a conservative estimate. The results of these changes are as follows:

Table 52: Estimated Direct Annual Costs (doubled) Graymont

Kiln	Capital Costs ($)	Direct Annual Costs ($)	Total Annual Costs ($)	NO_x Removed (tons)	cost-effectivenes s ($/ton)
1	$3,616,821	$180,574	$328,281	30	$10,943
2	$3,878,230	$186,204	$343,367	22	$15,608
3	$4,321,811	$208,776	$377,952	18	$20,997
4	$5,285,030	$258,458	$461,703	38	$12,150
5	$5,031,753	$289,720	$485,174	122	$ 3,977

Based on these revised results, the application of SNCR may appear to be feasible, at least for Kiln #5. Additional analysis should be provided by the source to further detail these deficiencies.

Graymont's Evaluation Response[150]

In order to obtain a more accurate capital and operating cost estimate, Graymont commissioned a Class 4 engineering cost estimate to ascertain capital and operating costs associated with installing and operating Selective Non-Catalytic Reduction (SNCR) Nitrogen Oxides (NO_x) abatement systems on Cricket Mountain kilns. The cost estimations performed by a third-party engineer indicate that the total capital cost for installation of SNCR systems at Cricket Mountain exceeds $6.9 MMUSD and operating costs exceed $1.4 MMUSD annually, resulting in a cost of $17,561 per ton of NO_x removed based upon a 20% removal efficiency. A factor of 20% was utilized based on the temperature and residence time limitations of the SNCR reaction zone for each Cricket Mountain kiln combined with the Low NO_x baseline concentration already achieved through the use of Low NO_x Burners (LNB)[151].

Graymont also compared the current NO_x emissions from Cricket Mountain to publicly available information for the Lhoist North America (LNA) rotary preheater kilns which utilize SCNR. Graymont offered the following observations:

- The existing LNBs at Cricket Mountain have effectively reduced the NO_x emission intensity to a level more than three times less than the pre-control NO_x intensity of LNA's Nelson Plant which utilizes SNCR.
- Any additive efficiency that might be gained from Cricket Mountain's use of SNCR would be marginal, at best, as SNCR NO_x removal efficiency is highly dependent upon the inlet NO_x concentration, reaction zone temperature and residence time, all of these factors reduce the anticipated efficiency that can reasonably be assumed for the Cricket Mountain Kilns.
- The LNA SNCR technology for rotary lime kilns is proprietary and not unconditionally commercially available to Graymont. The technology appears to be patented, adding to its cost and the uncertainty as to its technical feasibility.
- SNCR addition at Cricket Mountain would have unintended negative environmental impacts and visibility disbenefits, including the generation of condensable particulate, an identified regional haze primary pollutant.
- The Cricket Mountain facility operates 5 rotary preheat lime kilns, each of which are substantially different technology than mid-fired cement kilns (more conducive reaction zone temperatures, higher NO_x concentrations, and longer residence times). As such, it is not appropriate to draw direct comparisons with application of SNCR between cement kilns and lime kilns as referenced in your letter.

Based on Graymont's findings, requiring the installation of SNCR at Cricket Mountain would be unreasonable because it would be infeasible, unnecessary and counterproductive to making

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[150] Graymont's full evaluation response can be found in appendix C.2.C or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011722.pdf

[151] Lhoist North America indicated in a November 2020 4-factor analysis that Kilns 1, 2 & 3 would be capable of a maximum NO_x control of 20%.

reasonable progress towards the goal of preventing future, and remedying any existing, anthropogenic impairment of visibility in mandatory Class I Federal areas in the context of Utah's pending Round 2 Regional Haze State Implementation Plan (RH SIP). Cricket Mountain's successful implementation of LNBs effectively controls NO_x at the point of generation in kilns.

These NO_x rates are sufficient for inclusion in the UDAQ RH SIP since they are already some of the lowest achieved in the industry and far exceed what has been deemed BART at other kilns (such as the SNCR controlled kilns at the LNA Nelson Facility).

UDAQ Response Conclusion

UDAQ accepts Graymont's four-factor analysis amendments and additional justification on the unfeasibility of additional controls on the Cricket Mountain Facility's kilns. Refer to section 8.D.2 for UDAQ's controls for reasonable progress determination.

7.C.3 PacifiCorp's Hunter and Huntington Power Plants Four-Factor Analysis Summary and Evaluation[152]

Facility Identification

Name: Hunter Power Plant
Address: P.O. Box 569, Castle Dale, UT 84513
Owner/Operator: PacifiCorp
UTM coordinates: 497,800 m Easting, 4,335,800 m Northing, UTM Zone 12

Facility Process Summary

The Hunter Power Plant is located near Castle Dale in Emery County. The plant is classified as a PSD source and is a Phase II Acid Rain source. The source is PSD major for SO_2, NO_x, PM_{10}, and CO and also major for VOC and HAPs. The source is subject to the provisions of 40 CFR 52.21(aa); 40 CFR 60 Subparts A, D, Da, Y, and HHHH; and 40 CFR 63 Subparts A, ZZZZ, and UUUUU.

Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Steam Generating Unit #1 - Nominal 480 MW gross capacity dry bottom, tangentially-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during start-up and flame stabilization. System is equipped with a low-NO_x burner/overfire air system (OFA), baghouse, and SO_2 Wet FGD (WFGD) scrubber with no scrubber bypass.
- Steam Generating Unit #2 - Nominal 480 MW gross capacity dry bottom, tangentially-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during

[152] PacifiCorp's full four-factor analysis submittal for the Hunter and Huntington power plants can be found in appendix C.3.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008926.pdf

start-up and flame stabilization. System is equipped with a low-NO_x burner/OFA, baghouse, and SO_2 WFGD scrubber with no scrubber bypass.

- Steam Generating Unit #3 - Nominal 495 MW gross capacity dry bottom, wall-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during start-up and flame stabilization. System is equipped with baghouse, a low NO_x burner/OFA, and SO_2 FGD scrubber.

Facility Current Potential to Emit

The current PTE values for the Hunter Power Plant, as established by the most recent NSR permit issued to the source (DAQE-AN102370028-18) are as follows:

Table 53: Hunter Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
SO_2	5,537.5
NO_x	15,095

PacifiCorp Four Factor Analysis Conclusion

When balanced for Hunter Units 1, 2, and 3 the four factors demonstrate that the RPEL is the best option for making reasonable progress during the second planning period. First, installation of SNCR or SCR are not cost effective (even with the skewed depreciable life assumptions) and would result in hundreds of millions of dollars in costs for PacifiCorp customers, and tens of millions in additional operating costs for PacifiCorp. Implementation of the Hunter RPEL would not result in any significant additional costs for customers and would result in minimal additional operating costs. Second, installation of SNCR or SCR would involve long-lead times for permitting, design, procurement, and installation before reductions and compliance can be achieved. The Hunter RPEL requires negligible time for compliance, and could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. Third, SCR requires more energy to implement, and SNCR and SCR result in additional non-air environmental impacts over the Hunter RPEL. As documented, the Hunter RPEL has less potential consumption of natural resources, less GHG emissions, and less generation of CCR.

Fourth and finally, a requirement to install SCR or SNCR on Hunter Units 1, 2, and 3 would create uncertainty about the facility's remaining useful life. Many coal-fired power plants across the country have been forced to shut down due to the increased costs associated with SNCR and SCR. Implementing the Hunter RPEL would not be expected to either increase or decrease the remaining useful life of the facility. Based on this analysis, Utah should determine that the Hunter RPEL is the best option for achieving reasonable progress during the second planning period.

The Utah Division of Air Quality has indicated that photochemical grid modeling and analysis of visibility impacts will be performed by WRAP as part of the state's second planning period analysis. PacifiCorp anticipates that visibility modeling which incorporates the Hunter RPEL (and is compared to modeling of Hunter's current, permitted potential to emit) would assist the state in demonstrating reasonable progress at the CIAs impacted by emissions from the Hunter plant, supporting a conclusion that no additional installation of retrofit pollution control equipment is required at Hunter. However, if the State were to determine that the Hunter RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL (NO_x +SO_2 limit) for Hunter (allowing time for PacifiCorp to analyze the feasibility of the alternative RPEL proposal) as opposed to pursuing a requirement to install SNCR or SCR retrofits. This reasonable progress analysis demonstrates that implementing a RPEL is a better option than installing SNCR or SCR retrofits under each of the four statutory factors.

UDAQ Four-Factor Analysis Evaluation[153]

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four-factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
    a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
    a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Supplemental details regarding the RPEL approach, including the selection of allowable limits should be provided. The methodology used for setting the allowable limits should be discussed in detail.
5. Any other pertinent information PacifiCorp feels is warranted should also be provided in order to assist UDAQ in the review process.

Huntington Power Plant

Facility Identification

Name: Huntington Power Plant
Address: P.O. Box 680, Huntington, UT 84528
Owner/Operator: PacifiCorp
UTM coordinates: 493,130 Easting 4,358,840 Northing, UTM Zone 12

Facility Process Summary

The PacifiCorp Huntington Power Plant is a coal-fired steam electric generating facility consisting of two (2) boilers. Unit #1 is a 480 MW unit constructed in October 1973; Unit #2 is a 480 MW unit that commenced construction in April 1970. Bituminous and sub-bituminous coal is the primary fuel source for the dry bottom, tangentially-fired boilers. Fuel oil is used to start up the boilers from a cold start and for boiler flame stabilization. The Huntington Power Plant uses

[153] UDAQ's full four-factor analysis evaluation for the Hunter and Huntington power plants can be found in appendix C.3.B or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008926.pdf

low-NO_x burners, separated overfire air system, SO_2 FGD scrubber system, and pulse jet fabric filters for both units.

Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Boiler Unit #1 – Nominal 480 MW gross capacity dry bottom, tangentially-fired utility boiler fired on subbituminous and bituminous coal using fuel oil during startup and flame stabilization. Equipped with a fabric filter baghouse, low NO_x burners with overfire air system, and a SO_2 FGD scrubber. NSPS Subpart D.
- Boiler Unit #2 – Nominal 480 MW gross capacity dry bottom tangentially-fired utility boiler fired on subbituminous and bituminous coal using fuel oil during startup and flame stabilization. Equipped with a fabric filter baghouse, low-NO_x burners with overfire air system, and a SO_2 FGD scrubber.

Facility Current Potential to Emit

The current PTE values for the Huntington Power Plant, as established by the most recent NSR permit issued to the source (DAQE-AN102370028-18) are as follows:

Table 54: Current Potential to Emit: Huntington

Pollutant	Potential to Emit (Tons/Year)
SO_2	3,105
NO_x	7,971

PacifiCorp Four Factor Analysis Conclusion

When balanced for Huntington Units 1 and 2, the four factors demonstrate that the RPEL is the best option for making reasonable progress during the second planning period. First, installation of SNCR or SCR are not cost effective (even with the skewed depreciable life assumptions) and would result in hundreds of millions of dollars in costs for PacifiCorp customers, and tens of millions in additional operating costs for PacifiCorp. Implementation of the Huntington RPEL would not result in any significant additional costs for customers and would result in minimal additional operating costs. Second, installation of SNCR or SCR would involve long-lead times for permitting, design, procurement, and installation before reductions and compliance can be achieved. The Huntington RPEL requires negligible time for compliance, and could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. Third, SCR requires more energy to implement, and SNCR and SCR result in additional non-air environmental impacts over the Huntington RPEL. As documented, the Huntington RPEL has less potential consumption of natural resources, less GHG emissions, and less generation of CCR. Fourth and finally, a requirement to install SCR or SNCR on Huntington Units 1 and 2 would create uncertainty about the facility's remaining useful life. Many coal-fired power plants across the country have been forced to shut down due to the increased costs associated with SNCR and SCR. Implementing the Huntington RPEL would not be expected to either increase or decrease the remaining useful life of the facility. Based on this analysis, Utah should determine that the Huntington RPEL is the best option for achieving reasonable progress during the second planning period.

The Utah Division of Air Quality has indicated that photochemical grid modeling and analysis of visibility impacts will be performed by the Western Regional Air Partnership ("WRAP") as part of the state's second planning period analysis. PacifiCorp anticipates that visibility modeling which incorporates the Huntington RPEL (and is compared to modeling of Huntington's current, permitted potential to emit) would assist the state in demonstrating reasonable progress at the CIAs impacted by emissions from the Huntington plant, supporting a conclusion that no additional installation of retrofit pollution control equipment is required at Huntington. However, if the State were to determine that the Huntington RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL (NO_x +SO_2 limit) for Huntington (allowing time for PacifiCorp to analyze the feasibility of the alternative RPEL proposal) as opposed to pursuing a requirement to install SNCR or SCR retrofits. This reasonable progress analysis demonstrates that implementing a RPEL is a better option than installing SNCR or SCR retrofits under each of the four statutory factors.

UDAQ's Four Factor Analysis Conclusion

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four-factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
    a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
    a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Supplemental details regarding the RPEL approach, including the selection of allowable limits should be provided. The methodology used for setting the allowable limits should be discussed in detail.
5. Any other pertinent information PacifiCorp feels is warranted should also be provided in order to assist UDAQ in the review process.

PacifiCorp's Four-Factor Analysis Evaluation Response for Hunter and Huntington[154]

PacifiCorp proposed that UDAQ make the following adjustments to obtain a more representative cost effectiveness value for the installation of SNCR at the Hunter and Huntington plants:

• Utilize an SNCR NOx control efficiency of 20% for the Hunter and Huntington boilers, which is expected to be achievable based on unit size and firing configuration;

[154] PacifiCorp's full evaluation response for the Hunter and Huntington Power Plants can be found in appendix C.3.C or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011726.pdf

• Utilize capital and O&M costs provided by S&L which are site specific and more accurate than the generalized costs provided by the CCM model;

• Utilize PacifiCorp's actual weighted average cost of capital of 7.303% as the interest rate in the model instead of the 3.25% rate originally used by UDAQ;

• Utilize the current and accurate net MW generation rates and net unit heat rate provided in Table 1[155] to calculate boiler heat input; and lastly;

• Utilize the actual 2015-2019 average annual capacity factors in Table 3[156] instead of the rates included in Table 2, which are inaccurate.

PacifiCorp believed that use of the S&L capital and O&M cost data when combined with an SNCR 20% control efficiency and 7.303% interest rate will provide an accurate representation of unit-specific cost effectiveness. This is demonstrated by UDAQ's and PacifiCorp's SCR cost effectiveness determinations which provide essentially equivalent dollar-per-ton values. The following tables provide a summary of PacifiCorp's revised SNCR cost effectiveness values for the Hunter and Huntington plants applying these adjustments. The estimates are based on a systemwide SNCR control efficiency of 20% and an interest rate of 7.303%. Note that the provided values do not incorporate minor changes in annualized capital and O&M costs which will occur when the April 9, 2020, S&L studies are updated to incorporate the current 7.303% interest rate and use of the 20% SNCR NO_x control efficiency versus the studies' original use of a 7% interest rate and anticipated SNCR-controlled permit limit emission rates.

Table 55: PacifiCorp Updated Hunter SNCR Cost Effectiveness

Cost Effectiveness	Hunter 1	Hunter 2	Hunter 3
Baseline **Heat Input (MMBtu/year)** **NOx Emissions Rate (lb/MMBtu)** **NOx Emissions (tons/year)**	28,482,643 0.200 2,842	30,101,030 0.193 2,902	31,182,279 0.280 4,359
NOx Emissions w/ SNCR (20% efficiency) **Controlled NOx Emissions Rate (lb/MMBtu)** **Controlled NOx Emissions (tons/year)**	0.160 2,273	0.154 2,322	0.224 3,487
SNCR Annual NOx Removal (tons/year)	**568**	**580**	**872**
SNCR Cost Effectiveness (7.303% interest rate) **Annualized Capitalized Costs (20-yr life)** **Total Annualized O&M Costs**	$1,546,424 $2,168,400	$1,546,424 $2,208,800	$1,546,424 $3,176,600
Total Annual Cost ($/year)	**$3,714,824**	**$3,755,224**	**$4,723,024**
Cost effectiveness ($/ton)	**$6,536**	**$6,469**	**$5,417**

155 Located on page 4 of appendix C in PacifiCorp's Four Factor Analysis Evaluation Response
156 Located on page 5 of appendix C in PacifiCorp's Four Factor Analysis Evaluation Response

Table 56: PacifiCorp Updated Huntington SNCR Cost Effectiveness

Cost Effectiveness	Huntington 1	Huntington 2
Baseline **Heat Input (MMBtu/year)** **NOx Emissions Rate (lb/MMBtu)** **NOx Emissions (tons/year)**	28,063,728 0.212 2,968	27,150,145 0.208 2,825
NOx Emissions w/ SNCR (20% efficiency) **Controlled NOx Emissions Rate (lb/MMBtu)** **Controlled NOx Emissions (tons/year)**	0.169 2,374	0.166 2,260
SNCR Annual NOx Removal (tons/year)	**594**	**565**
SNCR Cost Effectiveness (7.303% interest rate) **Annualized Capitalized Costs (20-yr life)** **Total Annualized O&M Costs**	$1,560,724 $2,256,200	$1,560,724 $2,156,000
Total Annual Cost ($/year)	**$3,816,924**	**$3,716,724**
Cost effectiveness ($/ton)	**$6,431**	**$6,579**

In conclusion, PacifiCorp submitted that the above table's use of accurate annualized capital and O&M costs when combined with an appropriate SNCR NO_x control efficiency of 20% provide reasonable SNCR cost effectiveness determinations for the Hunter and Huntington units. PacifiCorp has requested that S&L update their April 9, 2020, studies to utilize the current interest rate of 7.303% and the more conservative SNCR NOx control efficiency of 20% for all Hunter and Huntington units. These updates are currently being finalized and are not anticipated to materially impact the data provided here. PacifiCorp will notify UDAQ if any material changes occur.

UDAQ Response Conclusion

Interest Rate

Upon consulting with the Control Cost Manual and EPA staff,[157] UDAQ has found that it is preferable for a source's four-factor analysis to use a source-specific interest rate. After further discussion with the Utah Department of Public Utilities, UDAQ has confirmed that 7.34% is PacifiCorp's most recently approved interest rate in Utah.[158] However, as noted in the company's Four-Factor Analysis Evaluation Response for Hunter and Huntington above, "The actual weighted average cost of capital is calculated using the rates approved by the six state regulatory authorities where PacifiCorp conducts business and the percentage of energy delivered by PacifiCorp to each of those states." UDAQ accepts the resulting 7.303% interest rate as an appropriate source-specific rate across the company's service territory and notes that this rate is more conservative than the Utah Public Service Commission approved 7.34% with regard to control-cost assessment.

[157] See email correspondence with Larry Sorrels (EPA) in Appendix D.2.H.
[158] Source: https://pscdocs.utah.gov/electric/20docs/2003504/3168662003504ro12-30-2020.pdf

SO_2

As noted above, all five units at both plants have FGD in place to control SO_2 emissions, and all units have SO_2 emission limits (generally 0.12 lb/MMBtu 30-day rolling average) that correspond to these controls as included in the approval orders for both plants. Since controls were installed/upgraded, all five units at both plants have operated at levels below the 0.12 lb/MMBtu SO_2 emission limits, ranging between approximately 0.6 and 0.10 lb/MMBtu as shown in Figure 53 below. UDAQ does not believe it is possible for the Hunter and Huntington units to scrub to the SO_2 emissions level of 0.03 lb/MMBtu specified in the original four-factor submittal RPEL proposal with the existing FGD controls. As PacifiCorp states in their comments[159]:

> *The Utah Units' SO_2 pollution control equipment (scrubbers) have design rates from 0.08 to 0.10 lb/MMBtu, and the costs indicated in the 2020 RP Analysis are to optimize these rates. The design parameters were necessary to ensure compliance with the Units' 0.12 lb/MMBtu emission limits. The existing Utah Units' scrubbers cannot control to lower SO_2 emission rates. To achieve a 0.03 lb/MMBtu SO_2 rate, new scrubbers would have to be constructed at an estimated capital cost of $180 million for each unit.*

UDAQ views the 0.03 lb/MMBtu rate as an artifact of the way the RPELs were calculated, and – as discussed in the NO_x section below – UDAQ does not concur with this methodology or the RPELs that result from it.

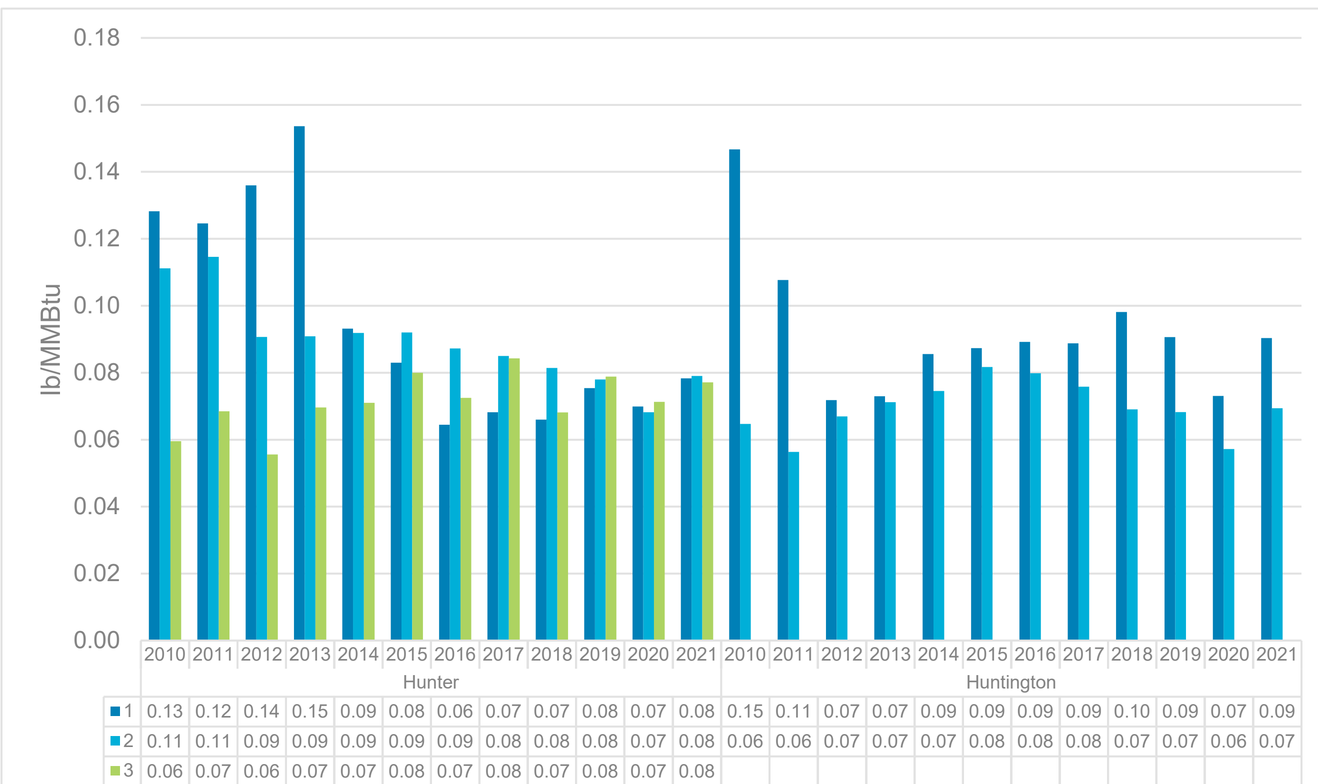

Figure 53: Hunter and Huntington SO_2 Rate

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[159] See appendix C.3.D to view PacifiCorp's response to comments regarding SO_2 scrubbing

The 2019 Guidance states that it “may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement.” The guidance goes on to provide “scenarios in which EPA believes it may be reasonable for a state not to select a particular source for further analysis,” including the following example:

> *For the purpose of SO_2 control measures, an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule47 for power plants. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO_2 is necessary to make reasonable progress.*

As previously stated, all of PacifiCorp’s Utah units have permitted SO_2 limits of 0.12 lb/MMBtu, which is well below the 0.2 lb/MMBtu limit provided in the 2019 Guidance.

For the foregoing reasons, UDAQ concludes that SO_2 emissions are well-controlled at all five Hunter and Huntington units. These units have operated at rates between 0.06 and 0.10 lb/MMBtu in recent years, and this range is consistent with the design parameters of the existing scrubbers. UDAQ also acknowledges that potential variations in the sulfur content of coal impact the ability of the existing controls to consistently scrub to lower levels in rejecting lower limits for these units.

Because Utah participated in the Section 309 compliance pathway for SO_2 in its round one SIP, the existing SO_2 emission limits were not included among the Section IX.H controls for regional haze. Since the continued operation of these controls is essential to making reasonable progress as demonstrated by the WRAP photochemical modeling and helps eliminate the possibility of backsliding on past emissions reductions, UDAQ is adding the existing SO_2 emission limits for all five units to SIP Section IX.H.23 to ensure federal enforceability in the regional haze context. However, UDAQ is eliminating the startup, shutdown, maintenance/planned outage or malfunction exemptions found in the approval order for Huntington Units 1 and 2 to ensure that the limits are applicable to these sources continuously to be consistent with CAA requirements.

NO_x

Four-factor Analyses

For NO_x controls, specifically SNCR and SCR, UDAQ concurs with PacifiCorp’s calculations supporting their four-factor analyses (as amended or further justified in the company’s follow-up submittals). However, UDAQ does not concur with the company's four-factor analysis calculations for the proposed RPELs. First, the emissions reductions ascribed to the RPELs were based upon the application of SNCR controls – a technology the company claimed not to be cost-effective – to each plant's plantwide applicability limit (PAL). Furthermore, the control costs associated with the RPELs were estimated based solely on the cost of additional scrubbing of SO_2, while the estimated emissions reductions included both NO_x and SO_2, and the RPEL cost-effectiveness analysis used an unrealistic baseline emissions scenario (i.e., 100% of the PAL). As a result, the RPEL cost-effectiveness estimates cannot be meaningfully compared to those for physical controls. For these reasons, UDAQ rejects the proposed RPELs.

Regarding SNCR and SCR cost-effectiveness, the company's analysis was based upon applying recent (2015-2019 average) heat inputs (in MMBtu/year) and emissions rates (in lb/MMBtu) to calculate emissions (MMBtu/year X lb/MMBtu = lb/year) compared to using the same heat inputs at the control emissions rates for SNCR and SCR. The delta between the recent actual emissions versus emissions with new controls represented the emissions reductions associated with each control. The total annual cost of each control was then divided by tons reduced per year to establish a cost-effectiveness metric of dollars per ton ($/ton) of emissions reduced.

PacifiCorp's analysis yielded cost-effectiveness values ranging from $5,417/ton to $6,579/ton for SNCR and $4,401/ton to $6,533/ton for SCR, as summarized in Table 57 below.

Table 57: Cost-effectiveness of SNCR and SCR and Hunter and Huntington Power Plants

Unit	SNCR $/ton	SCR $/ton
Hunter 1	$6,536	$6,533
Hunter 2	$6,469	$6,488
Hunter 3	$5,417	$4,401
Huntington 1	$6,431	$5,979
Huntington 2	$6,579	$6,294

As noted above, PacifiCorp's cost-effectiveness estimates were calculated using a baseline of recent actual emission levels. However, as EPA notes in its 2019 Guidance:

> *A state may choose a different emission control scenario as the analytical baseline scenario. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another.*[160]

[160] *See* Guidance on Regional Haze Implementation Plans for the Second Implementation Period (Aug. 20, 2019) (2019 Regional Haze Guidance) at 29, available at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

In its July 2021 clarifications memo, EPA adds that there may be instances in which state projections of changes in future utilization are unenforceable, leading to the need to establish utilization or production limits to ensure reasonable progress at existing emission rates:

> *. . . in some cases, states may have projected significantly lower total emissions due to unenforceable utilization or production assumptions and those projections are dispositive of the four-factor analysis. For example, a state that rejected new controls solely based on cost effectiveness values that were higher due to low utilization assumptions. In this circumstance, an emission limit that requires compliance with only an emission rate may not be able to reasonably ensure that the source's future emissions will be consistent with the assumptions relied upon for the reasonable progress determination. EPA anticipates these circumstances will be rare. One option a state may consider in this case is to incorporate a utilization or production limit corresponding to the assumption in the four-factor analysis into the SIP. Although not required, this approach is one way for states to address circumstances in which a specific emission rate does not, by itself, represent the reasonable progress determination.*[161]

Furthermore, EPA recognized that in instances in which control costs are dominated by a relatively high proportion of fixed capital costs, actual cost-effectiveness will be highly dependent on the future utilization levels of the facility. In instances where utilization is lower than initially projected, controls will be less cost-effective, while higher future utilization will result in improved cost-effectiveness, since there will be more tons reduced by a given control but for the same fixed costs when utilization increases. In such instances, EPA notes that a mass-based emission limit may be appropriate to demonstrate reasonable progress:

> *. . . if the annualized cost for a measure is dominated by fixed capital costs, the state may have determined that the measure is necessary to make reasonable progress if the operating level is high (making cost/ton and cost/Mm-1 relatively low) but not if the operating level is low (making cost/ton and cost/Mm-1 relatively high). In this case, a mass-based emission limit may be reasonable because it could relieve the source of the requirement to install the control if it manages its operating level strategically.*
>
> *. . . in addition to considering technology-based emission control measures, a state may consider restrictions on hours of operation, fuel input, or product output. Such restrictions could be implemented directly or by a time-based limit on mass emissions.*[162]

To further assess the appropriateness of installing physical controls at these facilities, UDAQ developed a plant utilization sensitivity analysis for installing SCR at all five units at both plants. In this analysis, UDAQ assumed a baseline emission scenario using historical utilization levels

[161] *See* Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) (2021 Regional Haze Clarifications) at 12, available at https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf.
[162] *See* 2019 Regional Haze Guidance at 45, available at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

(based on 2015-2019 actual emissions), and then varied potential future utilization relative to that baseline to create four alternative emissions scenarios:

- 125% of baseline utilization
- 75% of baseline utilization
- 50% of baseline utilization

UDAQ also scaled O&M costs by the same factors in an attempt to account for changes in variable costs but kept fixed capital costs constant. Figure 54 below summarizes this sensitivity analysis.

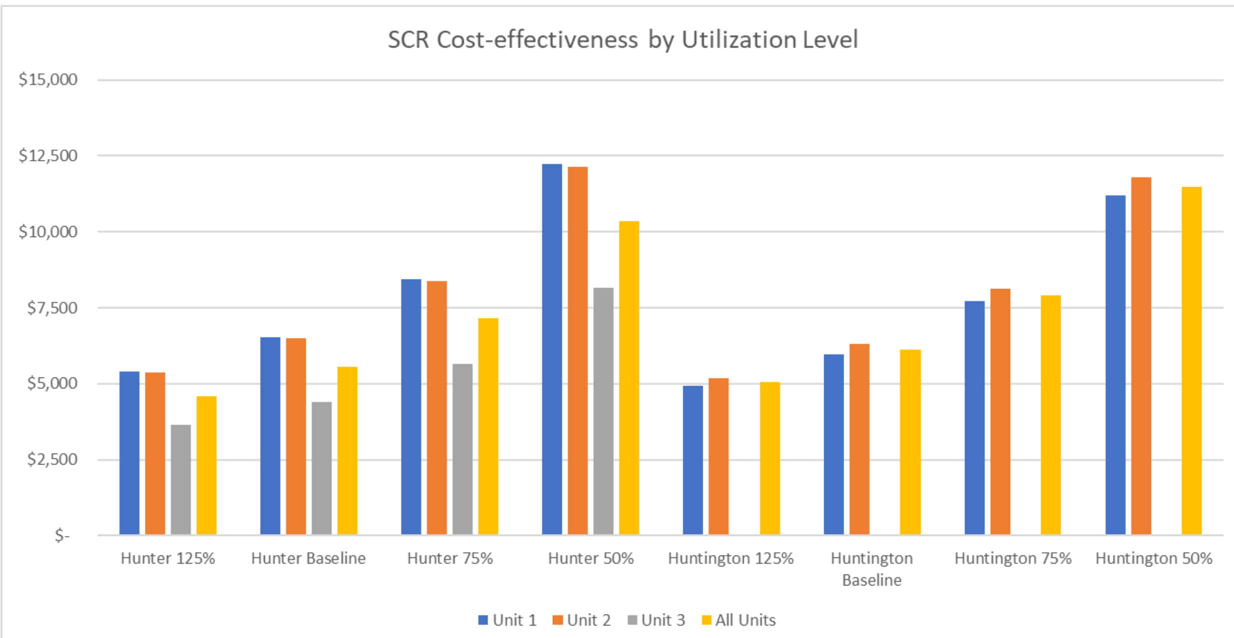

Figure 54: SCR Cost-effectiveness by utilization level at Hunter and Huntington Power Plants

As can be seen, higher unit and plant utilization yields lower $/ton estimates (more cost-effective), while lower utilization yields higher $/ton estimates (less cost-effective).

This sensitivity analysis raises the question of how the units at both plants are likely to be utilized throughout the second regional haze planning period. In its attempt to address this question, WRAP relied on the Center for the New Energy Economy (CNEE) at Colorado State University to project 2028 emissions for coal- and gas-fired EGUs throughout the West for use in modeling to support WRAP states in their SIP development.[163] For coal-fired units, these estimates were based on 2016-2018 utilization (i.e., gross load), heat rates, and emissions rates, but were adjusted for certain known or “on-the-books” (OTB) changes in emissions

[163] *See* http://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf.

controls, fuel switching, and unit closures. For example, in Utah, CNEE accounted for the previously announced closure of Intermountain Power Plant (IPP) Units 1 and 2 in 2025 by reducing emissions accordingly.

Using this OTB methodology, WRAP projected 2028 NO_x emissions of 10,001 tons/year for Hunter and 6,091 tons/year for Huntington.[164] These emissions estimates are similar though not identical to PacifiCorp's recent actual emissions used in its four-factor analyses, with the differences stemming from the use of different averaging periods and methodologies.

Anticipated Changes in Utilization

The electricity generation industry is experiencing significant change with the introduction of cheap natural gas and renewable sources such as wind and solar altering previous operating practices. Other factors affecting change include increased grid coordination (e.g., the Energy Imbalance Market (EIM), the potential establishment of a new Western regional transmission organization (RTO), new transmission capacity, etc.), dramatic improvements in lighting and other equipment efficiency, uncertainty regarding the future of climate regulation, and increased customer preference for cleaner energy resources. Low-cost renewable electricity in particular has forced operators to switch "baseload" EGUs, such as Utah's coal-fired plants, to "follow" load between periods when renewables are available and unavailable. This trend is reflected in the utilization[165] of the Hunter and Huntington power plants as shown in Figure 55 and Figure 56 below.

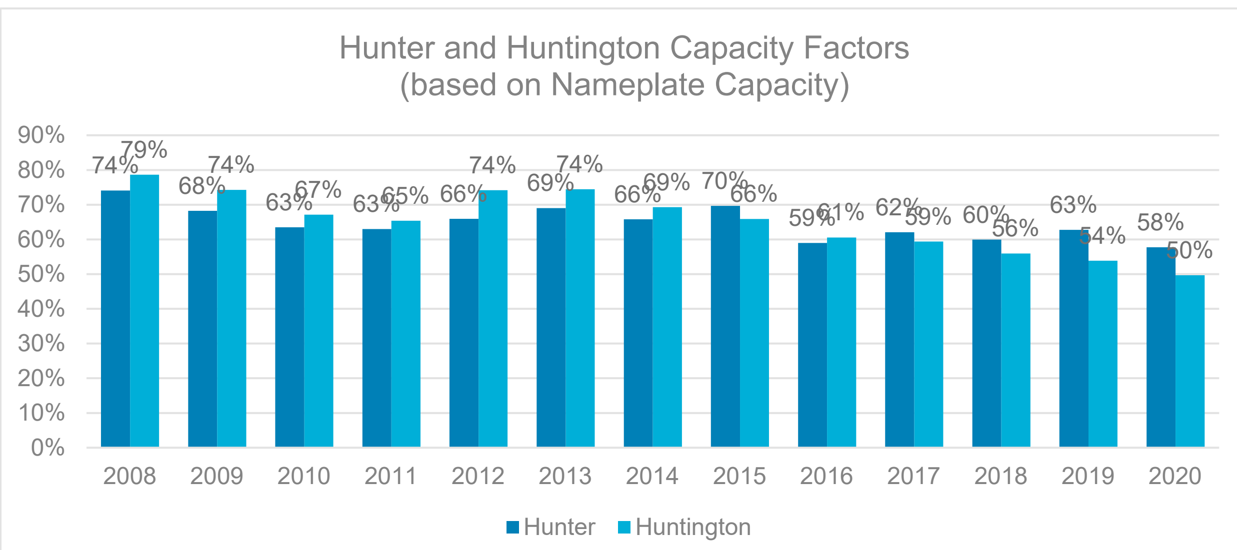

Figure 55: Hunter and Huntington Capacity Factors

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[164] CNEE originally estimated 9,992 tons/year for Hunter and 6,083 for Huntington, but the final WRAP projections included additional non-EGU sources at each plant to arrive at the values above.

[165] From Utah Geological Survey Energy *Utah Energy and Mineral Statistics,* Table 5.1 (https://geology.utah.gov/docs/statistics/electricity5.0/pdf/T5.1.pdf) and Table 5.15a (https://geology.utah.gov/docs/statistics/electricity5.0/pdf/T5.15.pdf).

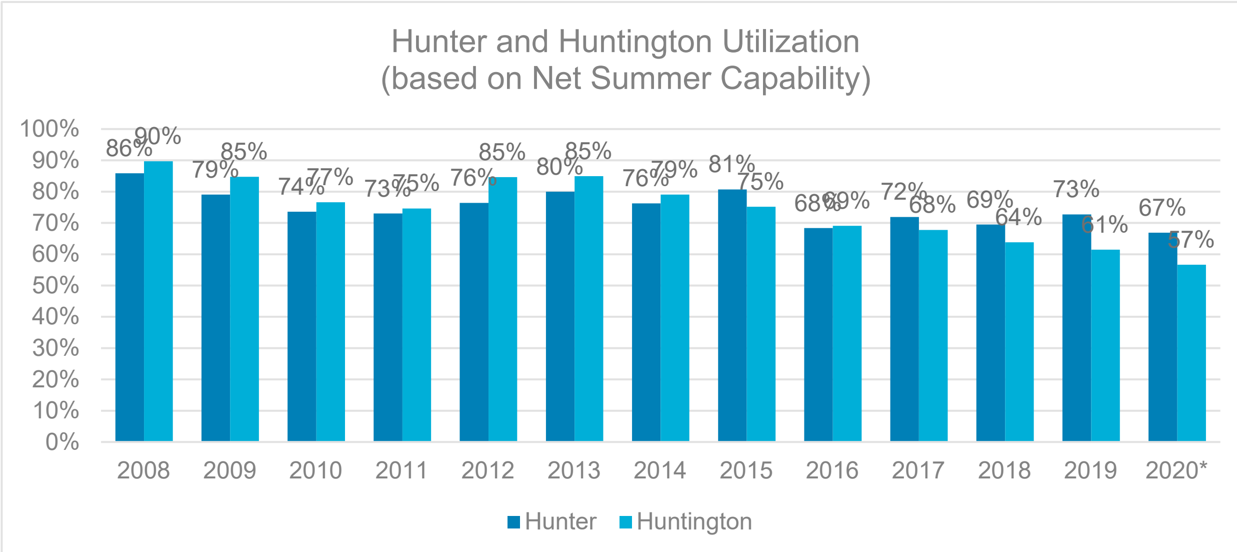

Figure 56: Hunter and Huntington Utilization (based on Net Summer Capability)

These changes in utilization, coupled with existing emission reduction controls, have led to decreases in NO_x emissions from Utah's coal-fueled EGUs, as shown in Figure 57.

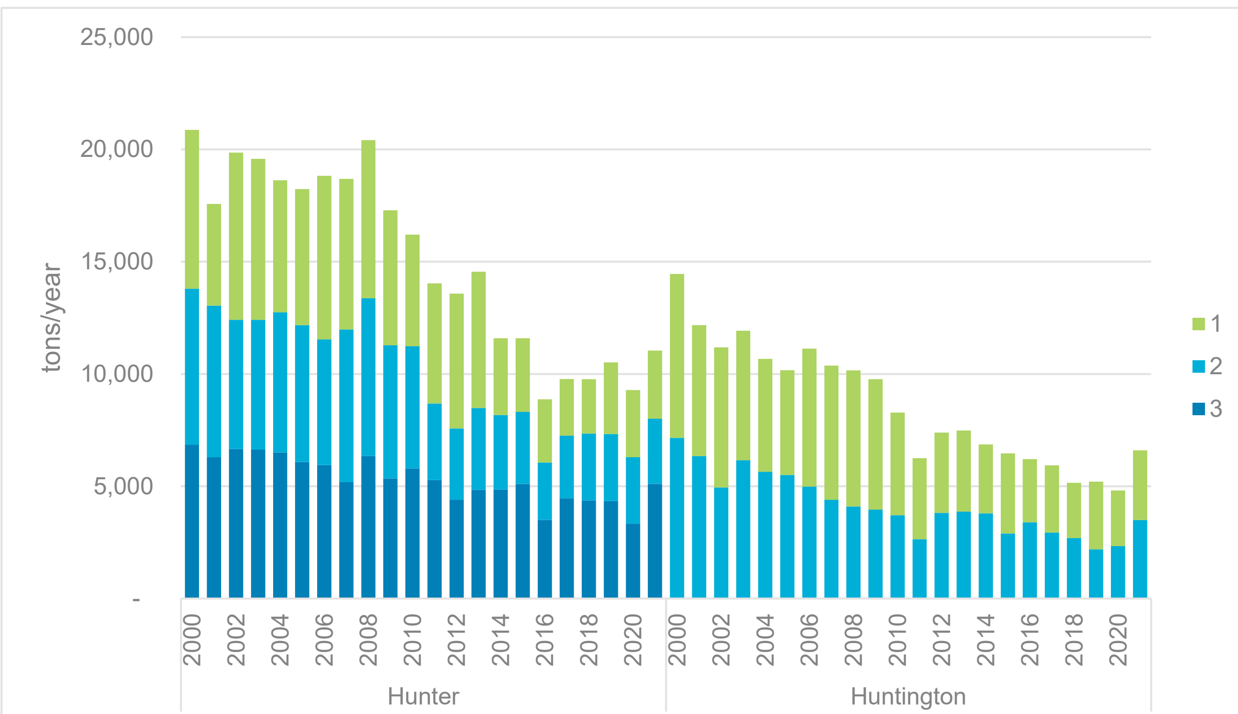

Figure 57: Hunter and Huntington NO_x Emissions by Unit

While there is always uncertainty regarding the future utilization of a facility, PacifiCorp's 2021 Integrated Resource Plan (IRP)[166] helps shed light on the likely future operation of Hunter and Huntington Power Plants. Indeed, it provides the company's most recent and robust assessment of the projected future resource utilization.

As shown in Figure 58 (2021 IRP Figures 1.4-1.7), the 2021 IRP preferred portfolio includes approximately 6,000 MW of new solar capacity, over 3,500 MW of new wind capacity, over 6,000 MW of new storage capacity, and over 2,500 MW of new non-emitting resources (e.g., hydrogen, nuclear, etc.) through 2040. Over the same period, it anticipates over 4,000 MW of coal retirements or conversion of coal units to natural gas, as shown in Figure 59 (2021 IRP Figure 1.12) below.

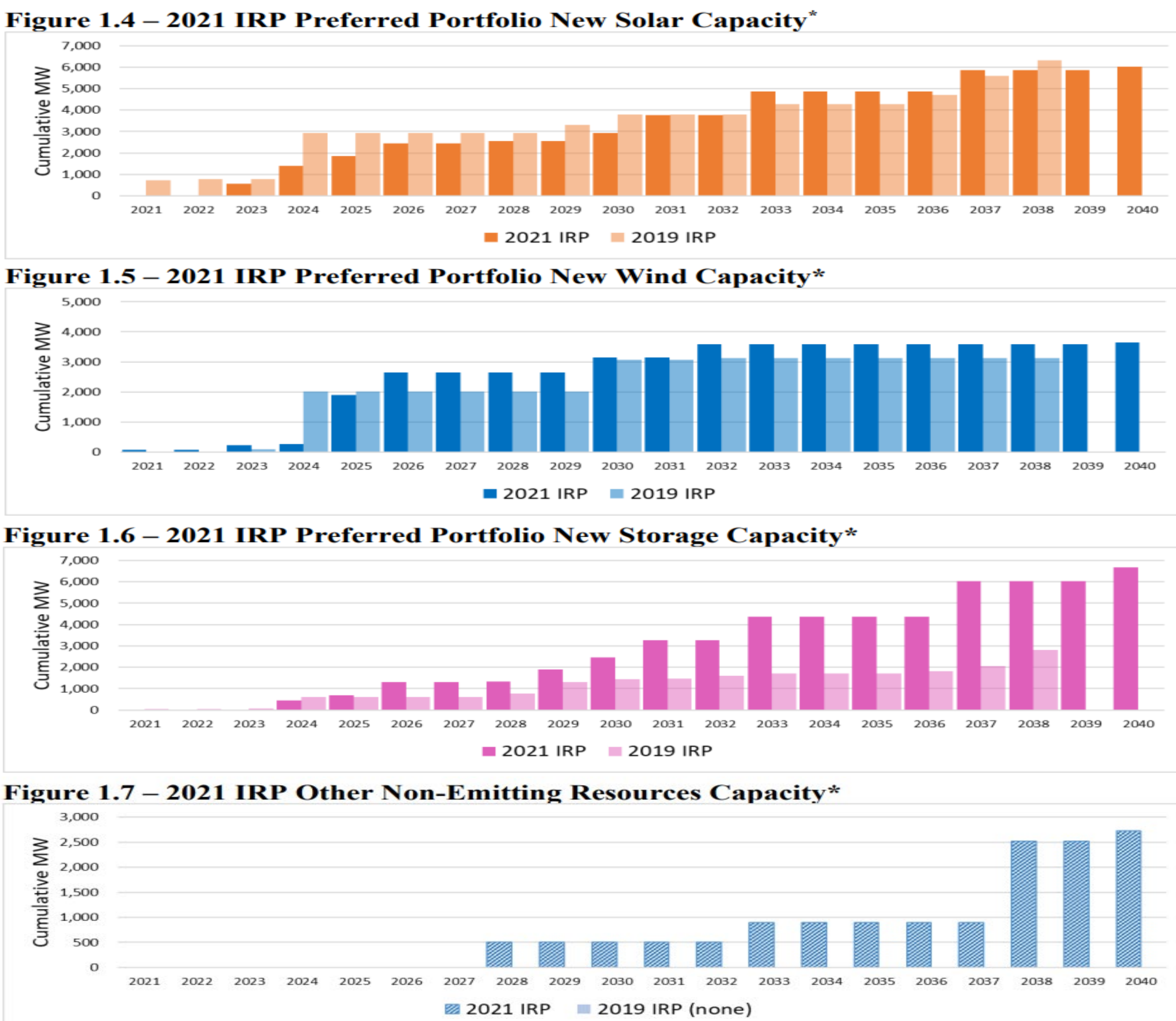

Figure 58: PacifiCorp 2021 IRP Cumulative Resource Additions

166 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

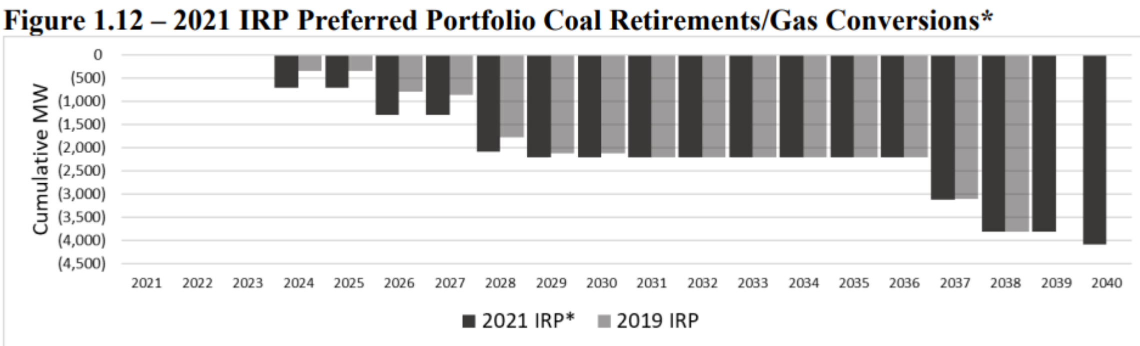

Figure 59: PacifiCorp 2021 IRP Cumulative Coal Retirements/Gas Conversions

Figure 60 compares PacifiCorp's remaining coal capacity (MW) to both the coal share of total energy (% of total MWh) and total capacity (% of total MW) over the 2021 IRP planning window. In 2021, coal-fired units are responsible for 49% of total energy, but only 31% of total capacity. Over time the coal energy share declines at a steeper rate than the coal capacity share as renewables and non-emitting resources enter PacifiCorp's system, with the metrics crossing each other in 2031 at 11%. By the end of the IRP planning window in 2040 when the Hunter

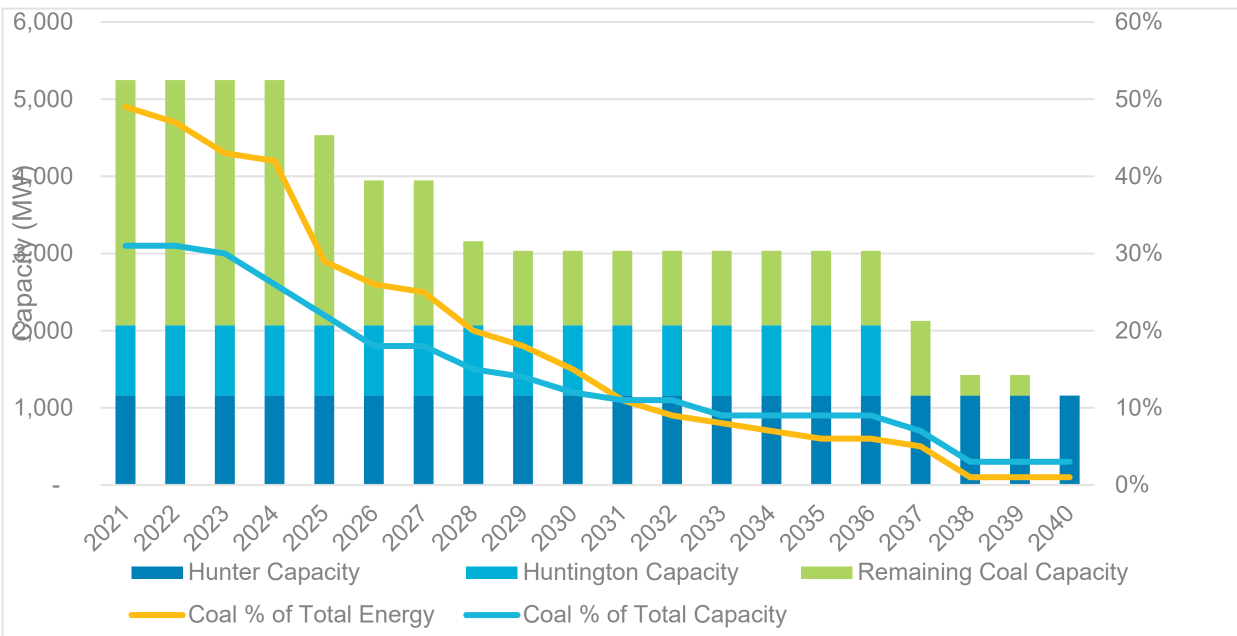

Figure 60: PacifiCorp 2021 IRP Coal Capacity (MW) vs. Coal % of Total Energy and % of Total Capacity

power plant is the only coal-fired unit remaining in PacifiCorp's system, the coal capacity share is only 3% and the coal energy share is only 1% of the total system. Importantly, it is energy generation, not capacity, that correlates with emissions levels for a given emission rate. Of particular interest is the period from 2029 through 2036 during which both in- and out-of-state coal capacity remains flat. Yet over the same period, the coal-fired share of total energy declines from 18% to just 6%. This chart helps illustrate that PacifiCorp's coal-fired units switch from being energy resource to capacity resources over time, as they transition to their new role of supporting zero-emission resources.

While the 2021 IRP projected plant-level and unit-level capacity factors for Hunter and Huntington are confidential and, therefore, not available to include in the SIP, the redacted comments of interveners before the Utah Public Service Commission (PSC) who have been granted access to these projections provide an additional degree of confidence that the utilization of these plants is likely to change. For example, excerpts from the redacted comments by Western Resource Advocates (WRA)[167] shed light on the projected future utilization of PacifiCorp's coal-fired plants:

> *With the planned new resources in PacifiCorp's Preferred Portfolio, the transformation of PacifiCorp's coal fleet is projected to accelerate significantly over the coming decade from the provision of round-the-clock energy to seasonal dispatch with limited annual hours of operation. (page 10)*
>
> *Confidential Exhibit 4 is comprised of six pages, and displays monthly capacity factors for PacifiCorp's long-lived coal plants: Jim Bridger, Wyodak, Hunter, and Huntington. A review of the exhibit makes clear that once take-or-pay contracts expire, the units at Hunter and Huntington operate only seasonally… (pages 15-16)*

Affordability

In addition to concerns that reduced future plant utilization will erode the cost-effectiveness of physical controls at Hunter and Huntington, it is important to note that PacifiCorp believes that these controls are unaffordable under the current constraints the company faces as a regulated public utility and in the face of post-pandemic supply chain issues and rising inflation. As PacifiCorp states[168]:

> *…the dollar-per-ton cost-effectiveness value for SCR does not represent all of the considerations necessary to determine whether SCR is a reasonable control that should be required at the Utah Units. As the Affordability Analysis shows, a demonstration that SCR is the least-cost, least-risk option for PacifiCorp's customers faces likely insurmountable obstacles. In addition, over the past decade, the requirement to install SCR has led to early retirement or refueling of numerous other coal-fueled generating plants in the region and across the country. External factors including increased regulatory scrutiny of investments in coal-fueled resources, state laws limiting the market for coal-fueled power and increasing competition from renewable and storage resources add to the pressures making SCR unaffordable, especially for a regulated utility. The decision to retire a coal-fueled unit rather than install SCR is not merely "a voluntary business decision[ ] that the benefits of continuing to generate electricity at the affected units were outweighed" by other factors. Instead, an early retirement decision is a*

[167] See https://pscdocs.utah.gov/electric/21docs/2103509/322689RdctdWRACmnts3-4-2022.pdf.

[168] PacifiCorp's public comment period submission can be found at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2022-007454.pdf

regulatory necessity as continued plant operation becomes unfeasible because "the costs of [SCR] . . . [are] so onerous that the source[ ] simply could not afford them" making "the sources' decisions to cease operations . . . in essence involuntary."

In the Wyodak Facility SCR Affordability Analysis (August 25, 2020) supplied with their public comments on the proposed SIP, PacifiCorp identifies several coal units across the country that have either been retired or repowered rather than installing SCR to meet regulatory requirements, including:

- Cholla Plant, Arizona
- Craig Unit 1, Colorado
- San Juan Generating Station (retirement of two of four units), New Mexico
- Progress Energy and Duke have shut down 22 units subject to BART instead of installing controls, North Carolina
- Boardman Plant elected to cease burning coal instead of installing SCR, Oregon
- Dave Johnson Plan will retire Unit 3 by 2027 rather than installing SCR, Wyoming

More recently, PacifiCorp has announced that it will convert Jim Bridger 1 and 2 to natural gas rather than installing SCR.

Affordability concerns have led some 2021 IRP commenters to opine that SCR might be considered an imprudent investment relative to unit closures in the economic regulatory arena, including parties who in their round two proposed SIP comments to UDAQ claim SCR to be a cost-effective control. For example, in redacted comments before the Utah PSC, the Sierra Club states, "SCR requirements will at some point be required under the Clean Air Act. At that time, the early retirement case becomes roughly equivalent from an economic standpoint to the current preferred case, depending on the price-policy scenario."[169] Here it is important to note that EPA has historically held that it does not have the authority to force the retirement of a unit under the regional haze rule: "Generally, EPA does not interpret the regional haze rule to provide us with authority to make a BART determination that requires the shutdown of a source."[170]

Additional affordability concerns were raised in public comments from Deseret Power, which owns an undivided 25.108% of Hunter Unit 2. Deseret states[171]:

For over 20 years, Deseret has operated as a financially distressed company under the terms of a troubled debt forbearance (the "Debt Forbearance") with its principal creditor. Under the terms of the Debt Forbearance, Deseret essentially pledged all of its available net cashflow toward partial payment of long-term indebtedness which Deseret has been unable to pay in full. A key provision of the Debt Forbearance is that Deseret cannot

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[169] See https://pscdocs.utah.gov/electric/21docs/2103509/322718RdctdSierraClubCmnts3-4-2022.pdf

[170] 79 FR 5032, 5045 (Jan. 30, 2014).

[171] The public comments submitted by Deseret Power can be found at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2022-007475.pdf

incur any added indebtedness without prior express consent of the existing creditor. The creditor understandably does not allow Deseret to take on new debt without first scrutinizing whether and to what extent the new debt would result in increased net cashflows to help repay the outstanding arrearage on existing debt held by the creditor.

In its present condition, Deseret is not certain it would be able to raise capital necessary to finance its portion of costs to install any additional and costly post-combustion controls at Hunter II. It would be left to the decision of Deseret's creditor to refuse to allow Deseret to solicit or draw on any new source of financing for such controls.

These affordability concerns and the potential for forced unit closures weigh in favor of considering reasonable alternatives to requiring the installation of physical controls.

Balancing the Four Statutory Factors

Given the likely reduction in utilization of Hunter and Huntington in future years and the erosion of the cost-effectiveness of physical controls that would accompany such a reduction, UDAQ is establishing enforceable mass-based limits on future emissions from these facilities to reduce uncertainty and ensure that the plants operate at or below emissions levels at which physical controls are not cost-effective. To identify these limits, UDAQ calculated the utilization and resulting emissions levels that would result in a $5,750/ton level for SNCR and SCR for all units at both plants, as shown in Table 58 and Table 59 below. UDAQ then used the more stringent of the two scenarios (based on SCR) to set limits at which both SNCR and SCR are not cost-effective.

Table 58: 2028 Mass-based NO_x Limit - SNCR Cost-effectiveness

Item (unit)	Hunter 1	Hunter 2	Hunter 3	Huntington 1	Huntington 2	Total
2028 Utilization (% of 2015-2019 Average)	144.6%	134.2%	85.6%	133.0%	138.3%	
2015-2019 Average Heat Input (MMBTU)	28,482,643	30,101,030	31,182,279	28,063,728	27,150,145	
2028 Limit Heat Input (MMBTU)	41,183,800	40,400,840	26,683,091	37,329,312	37,542,964	
Existing Control Rate (lb/MMBTU)	0.200	0.193	0.280	0.212	0.208	
Proposed Control Rate (lb/MMBTU)	0.160	0.154	0.224	0.169	0.166	
Emissions w/ Existing Controls (tons/year)	4,109	3,895	3,730	3,948	3,906	
Emissions w/ Control (tons/year)	3,295	3,111	2,989	3,154	3,116	
Emissions Reduction (tons/year)	814	785	742	793	790	
Annualized Capital Costs	$1,546,424	$1,546,424	$1,546,424	$ 1,560,724	$ 1,560,724	
Total Annual O&M Costs	$ 3,135,346	$ 2,964,595	$ 2,718,259	$ 3,001,112	$ 2,981,296	
Total Annual Cost	$4,681,770	$4,511,019	$4,264,683	$4,561,836	$4,542,020	
$/ton	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	
2028 Emission Limit (tons)		**Hunter Plantwide:**	**11,735**	**Huntington Plantwide:**	**7,854**	**19,588**

Table 59: 2028 Mass-based NO_x Limit – SCR Cost-effectiveness

Item (unit)	Hunter 1	Hunter 2	Hunter 3	Huntington 1	Huntington 2	Total

2028 Utilization (% of 2015-2019 Average)	115.9%	115.0%	73.6%	104.6%	111.0%	
2015-2019 Average Heat Input (MMBTU)	28,482,643	30,101,030	31,182,279	28,063,728	27,150,145	
2028 Limit Heat Input (MMBTU)	33,016,004	34,628,669	22,963,607	29,357,153	30,136,124	
Existing Control Rate (lb/MMBTU)	0.1995	0.1928	0.2796	0.2115	0.2081	
Proposed Control Rate (lb/MMBTU)	0.0500	0.0500	0.0500	0.0500	0.0500	
Emissions w/ Existing Controls (tons/year)	3,294	3,339	3,210	3,105	3,135	
Emissions w/ Control (tons/year)	825	866	574	734	753	
Emissions Reduction (tons/year)	2,469	2,473	2,636	2,371	2,382	
Annualized Capital Costs	$12,141,691	$12,141,691	$13,490,472	$11,787,158	$11,787,158	
Total Annual O&M Costs	$ 2,052,876	$ 2,078,799	$ 1,667,280	$ 1,844,255	$ 1,909,166	
Total Annual Cost	$14,194,567	$14,220,490	$15,157,752	$13,631,413	$13,696,324	
$/ton	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	
2028 Emission Limit (tons)		**Hunter Plantwide:**	**9,843**	**Huntington Plantwide:**	**6,240**	**16,083**

While UDAQ is not establishing a cost-effectiveness threshold per se, the agency believes that a level of $5,750/ton for physical controls, when balanced against the remaining three statutory factors, is not cost-effective. As a result, UDAQ concludes that physical controls are not necessary to demonstrate reasonable progress. What follows is a brief summary of the remaining factors, beyond cost-effectiveness, that help in leading UDAQ to this conclusion:

Time Necessary for Compliance
Due to the delayed nature of the round 2 regional haze SIPs, there is only a short window available for control installation of approximately five years, depending the final approval date. This is likely not enough time for the potential installation of SNCR or SCR at up to five units. In contrast, enforceable annual mass-based limits can begin to be implemented immediately upon approval of the round 2 regional haze SIP.

Energy and non-air quality environmental impacts
According to PacifiCorp's four-factor analysis, the installation of SCR on Hunter and Huntington would result in a large parasitic load of 12.5 MW at Hunter and 8.6 MW at Huntington, which equates to 115,687 and 79,743 more tons of CO_2, respectively. In addition, the installation of SNCR or SCR could potentially lead to increases in water use, coal consumption, coal combustion residuals, and other consumables and waste products associated with coal combustion (e.g., water treatment chemicals, anhydrous ammonia reagent, urea reagent, mercury control system reagent, and diesel fuel), since physical controls would enable the plants to operate more under the existing PALs relative to mass-based limits. In addition, these plants are currently projected to assist in the transition towards intermittent renewable resources. Should the cost of physical controls lead to early plant closures, alternative resources will be required to provide such support.

Remaining Useful Life

The currently anticipated economic life of Huntington is approximately 14 years (16 years fewer than EPA's 30-year control life of SCR). The economic life of Hunter is approximately 20 years (10 years fewer than EPA's 30-year control life of SCR). While the respective closure years of 2036 and 2042 are not currently enforceable, closure of these facilities at or before the end of their economic life would further erode the cost-effectiveness of physical controls by shortening the amortization period for control costs. Ongoing scrutiny of expenditures associated with coal-fired power plants by state public service commissions and the establishment of clean energy requirements in California, Oregon, and Washington increase the risk that these facilities may face early closure.

Mass-based Limits and Flexible Compliance

While Table 59 above shows the emissions levels that would result from constraining cost-effectiveness at $5,750/ton for SCR at the unit level, UDAQ is summing these estimated unit-level emissions at each plant to develop plantwide emission limits to provide compliance flexibility. In particular, UDAQ is establishing a 2028 plantwide NO_x limit of 9,843 tons per year for Hunter and a 2028 plantwide NO_x limit of 6,240 tons per year for Huntington. In addition, UDAQ is establishing an initial plantwide NO_x limit for Hunter of 11,041 tons per year and an initial plantwide NO_x limit for Huntington of 6,604 tons per year, both effective upon SIP approval. These initial levels are based on each plant's highest emission value over the past five years (2017-2021). Finally, UDAQ is establishing an interim 2025 plantwide limit of 10,442 tons per year for Hunter and an interim 2025 plantwide limit of 6,422 tons per year for Huntington, to create a compliance glidepath to aid in the transition from recent actual utilization levels to the final 2028 limits. The interim limits for each plant were calculated as the average of (i.e., the midpoint between) the initial and 2028 plantwide limits for each plant. The limits are compared to recent actual emissions and the outgoing PAL in Table 60 and Table 61 below. UDAQ notes that flexible compliance mechanisms such as plantwide limits and glidepaths are commonly used in environmental regulation (e.g., plantwide applicability limits; Tier 3 fuel averaging, banking, and trading; the Tier 3 vehicle fleet averaging glidepath from 2017-2025; cap and trade programs, etc.) and are appropriate in this application.

Table 60: Hunter Actuals and Limits

Year or Limit	Unit 1	Unit 2	Unit 3	Total
2015	3,274	3,210	5,107	11,591
2016	2,806	2,556	3,506	8,869
2017	2,518	2,789	4,466	9,773
2018	2,422	2,975	4,372	9,770
2019	3,188	2,981	4,344	10,514
2020	2,996	2,955	3,336	9,287
2021	3,032	2,905	5,103	11,041
2022 Initial Limit				**11,041**
2025 Interim Limit				**10,442**
2028 Final Limit				**9,843**
Outgoing PAL				**15,095**

Table 61: Huntington Actuals and Limits

Year or Limit	Unit 1	Unit 2		Total
2015	3,563	2,899		6,462
2016	2,810	3,400		6,210
2017	2,990	2,940		5,931
2018	2,462	2,692		5,153
2019	3,013	2,193		5,206
2020	2,476	2,337		4,814
2021	3,111	3,493		6,604
2022 Initial Limit				**6,604**
2025 Interim Limit				**6,422**
2028 Final Limit				**6,240**
Outgoing PAL				**7,971**

As discussed previously, UDAQ has historically used plantwide limits (i.e., PALs) to limit emissions from Hunter and Huntington power plants while providing PacifiCorp operational flexibility. According to EPA's 2020 "Guidance on Plantwide Applicability Limitation Provisions Under the New Source Review Regulations":[172]

> *A PAL is an optional flexible permitting mechanism available to major stationary sources that involves the establishment of a plantwide emissions limit, in tons per year, for a regulated NSR pollutant. A PAL represents a simplified NSR applicability approach that provides a source with the ability to manage physical and operational changes, and the impacts of those changes on facility-wide emissions, without triggering major NSR or the need to conduct project-by-project major NSR applicability analyses. The added flexibility of a PAL allows a source to respond rapidly to market changes with reduced permitting burden and greater regulatory certainty.*

While sources may favor such regulatory flexibility, the ability for emissions to vary from unit to unit under a plantwide limit raises the question of how such variations might impact visibility at CIAs. On this point, UDAQ notes that the distance between the outermost stacks at Hunter is approximately 596 feet, and the distance between the stacks for units 1 and 2 at Huntington is 265 feet. In contrast, the distance between each plant and the CANYI IMPROVE monitor for Arches and Canyonlands is 431,589 feet (Hunter) and 490,433 feet (Huntington). While distances from these facilities to each IMPROVE site vary, the CANY1 example illustrates that differences in visibility impairment that stem from the proximity effects associated with plantwide limits are likely to be negligible. Visibility impacts related to using plantwide limits are more likely to stem from other factors that might favor or constrain the utilization of one unit relative to other units than from differences in proximity to CIAs among units.

[172] https://www.epa.gov/sites/default/files/2020-08/documents/pal_guidance_final_-_signed.pdf

Cost-effectiveness Thresholds

On the subject of decision thresholds, the 2019 Guidance notes that states “may” use thresholds, but the use of such thresholds must be justified with respect to consideration for other relevant factors:

> *A state may find it useful to develop thresholds for single metrics to organize and guide its decision-making. As the Ninth Circuit explained in NPCA v. EPA, 788 F.3d at 1142, the Regional Haze Rule does not prevent states from implementing “bright line” rules, such as thresholds, when considering costs and visibility benefits. However, the state must explain the basis for any thresholds or other rules (see 40 CFR 51.308(f)(2)). If a state applies a threshold for any particular metric to remove control measures from further consideration before all other relevant factors are considered, it should explain why its selected threshold is appropriate for that purpose, i.e., why its application is consistent with the requirement to make reasonable progress.*

In general, UDAQ believes that such “bright line” thresholds are neither required nor appropriate for determining reasonable progress. As discussed in Section 7.A.1 regarding the selection of sources for controls determination, UDAQ’s Q/d threshold value of 6 is only the starting point for screening sources for further evaluation. UDAQ augments this threshold with both a secondary screening and a WEP analysis to ensure that it has accurately captured sources in need of evaluation. Similarly, a bright line cost-effectiveness threshold (i.e., cost/ton) is not required and may be of limited utility. In fact, the 2019 Guidance states that such cost/ton thresholds must be justified, and comparisons among various cost/ton estimates may or may not be useful for assessing compliance costs:

> *If a state applies a threshold for cost/ton to evaluate control measures, we recommend that the SIP explain why the selected threshold is appropriate for that purpose and consistent with the requirement to make reasonable progress.*
>
> *… a cost/ton metric and comparisons to the cost/ton values for measures that have been previously implemented may or may not be useful in determining the reasonableness of compliance costs.*

Historically, UDAQ has not utilized cost-effectiveness thresholds for compliance cost assessment, whether for RACT, BACT, or other air quality program control measures. Selecting a cost-effectiveness threshold provides a “target” that sources could potentially exploit to adjust their compliance cost analyses to avoid control requirements. In the round 2 regional haze context, the selection of a bright line $/ton threshold would inappropriately limit UDAQ’s ability to consider the remaining three statutory factors and related considerations. That said, a review of cost-effectiveness thresholds and ranges in various states – either incorporated directly into regional haze SIPs, used internally by staff and shared via the interstate coordination process, or shared by commenters on the proposed SIP – reveals that UDAQ’s determination that physical controls are not cost-effective at a $5,750/ton level is in line with the range considered by other states as shown in Figure 61 below.

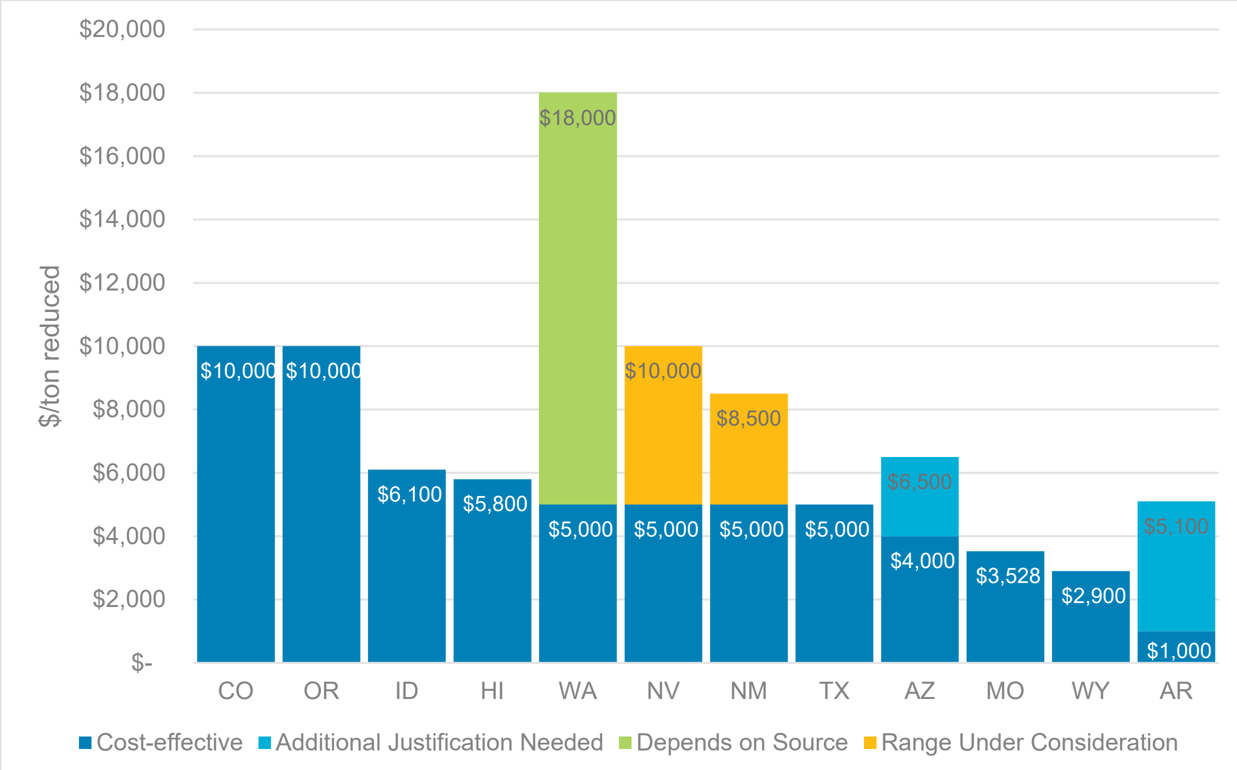

Figure 61: State Control Cost-effectiveness Ranges

Annual Limits vs. Short-term Limits or Emission Rates

Given concerns that the use of an annual limit might not be sufficiently short to limit visibility impairment on Most Impaired Days (MIDs), UDAQ evaluated the seasonality of nitrate impairment on MIDs at Utah's CIAs using the last five available years of visibility data.[173] As shown in Figure 62, nitrate impairment is largely seasonal with the MIDs with the highest light extinction happening during the winter months. This result is consistent with the secondary formation of particulates that UDAQ sees along the Wasatch Front and is not unexpected.

[173] Source: "TSS Ambient Species Composition of Daily Light Extinction by Percentile Days - Product #XATP_ECSB_GDYR." WRAP Technical Support System (TSS); The Western Regional Air Partnership (WRAP) and the Cooperative Institute for Research in the Atmosphere (CIRA), 20 Jun 2022

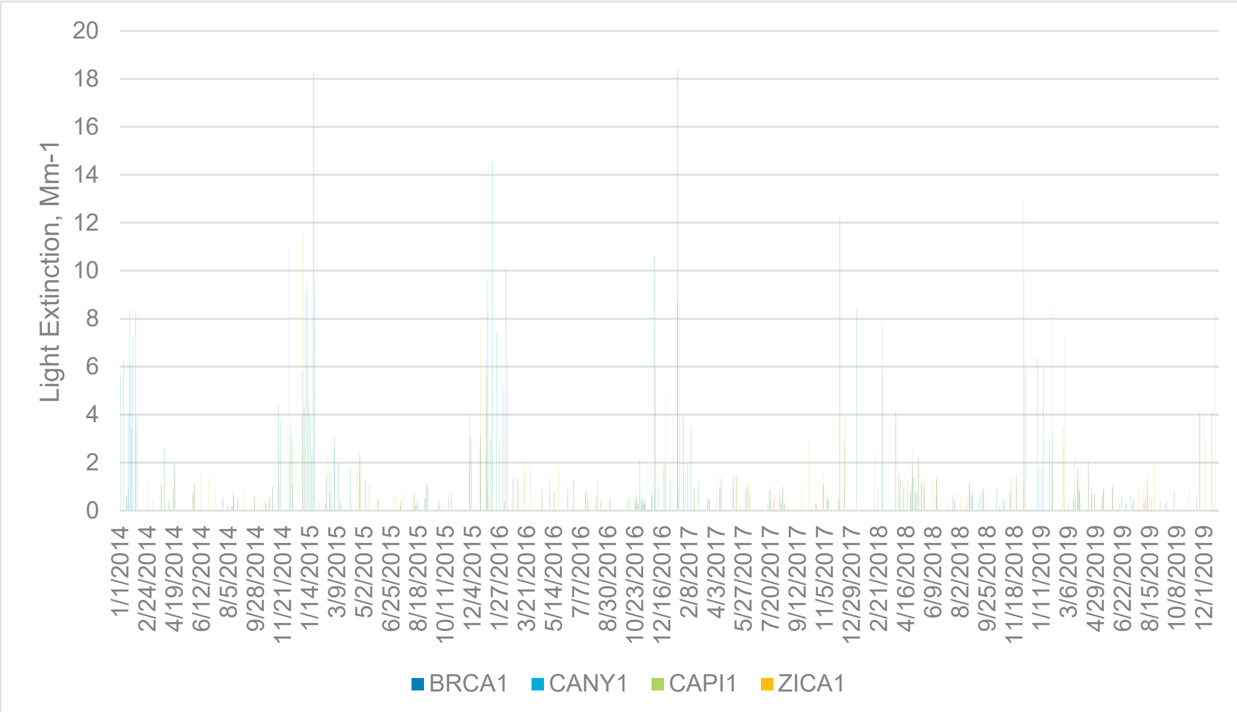

Figure 62: Daily Nitrate Light Extinction MIDs at Utah CIA IMPROVE Sites, 2014-2019

While nitrate light extinction has a single annual peak in the wintertime, the Hunter and Huntington power plants have two gross load (and associated NO_x emissions) peaks each year, one in the summer and one in the winter, as shown in Figure 63 below. As a result, UDAQ believes that the company is unlikely to utilize the majority of its annual mass-based NO_x limit for each plant during the wintertime gross load and MID nitrate impairment peaks, since it must retain enough headroom to accommodate the summer gross load peak. Thus, UDAQ concludes that an annual mass-based limit is a sufficient to reduce the likelihood of excess emissions impact CIAs during periods of high electricity demand.

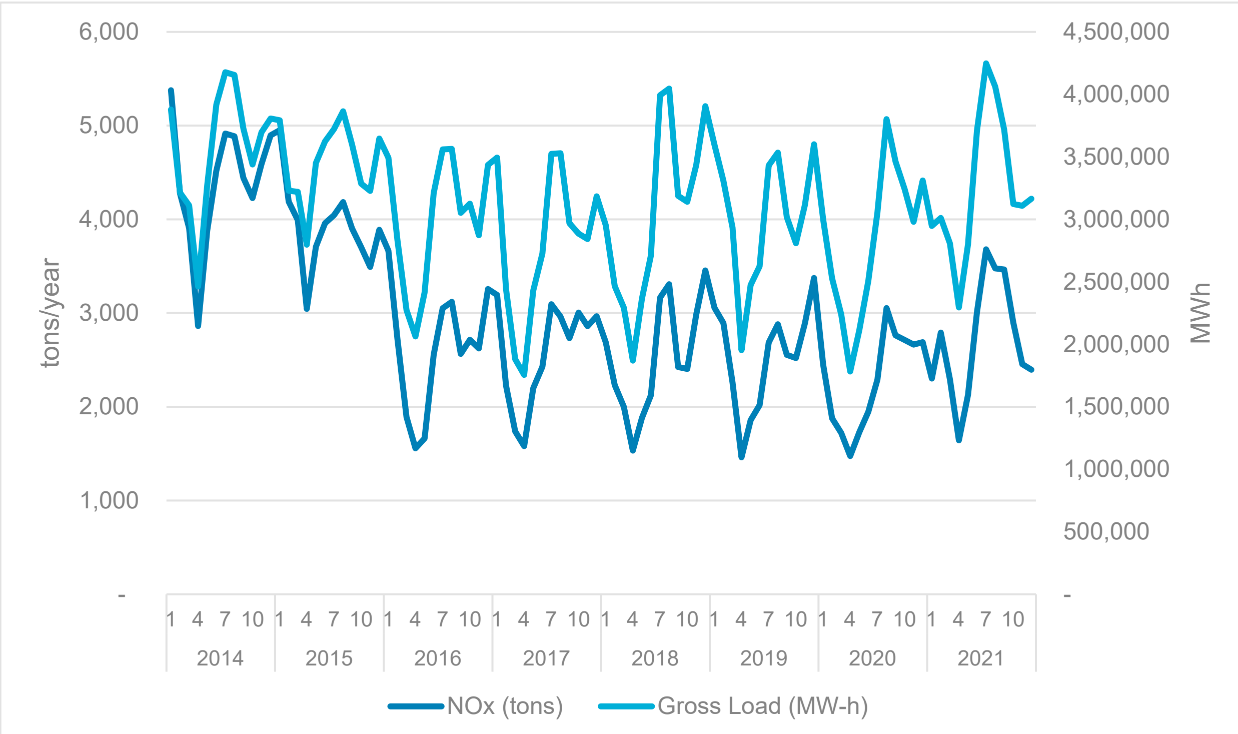

Figure 63: Combined Hunter and Huntington Monthly NOx Emissions vs. Monthly Gross Load, 2014-2021

Other Considerations

UDAQ finds it additionally compelling to incorporate these enforceable mass-based emission limits to ensure that the EGU nitrate contribution to light extinction at Utah (and other states) CIAs does not exceed the emissions levels utilized in WRAP's photochemical modeling.[174] Such mass-based emission limits would help ensure that Utah is making reasonable progress as demonstrated by the WRAP modeling, while eliminating the possibility of backsliding on past emissions reductions. Importantly, the mass-based emissions limits outlined above result in combined emissions that are generally consistent with WRAP's 2028 OTB projections that are explicitly accounted for in Utah's projected 2028 RPGs, such as the example shown for Canyonlands in Figure 64.

[174] See Appendix A for UDAQ's proposed Part H language for emission limits and controls enforcement

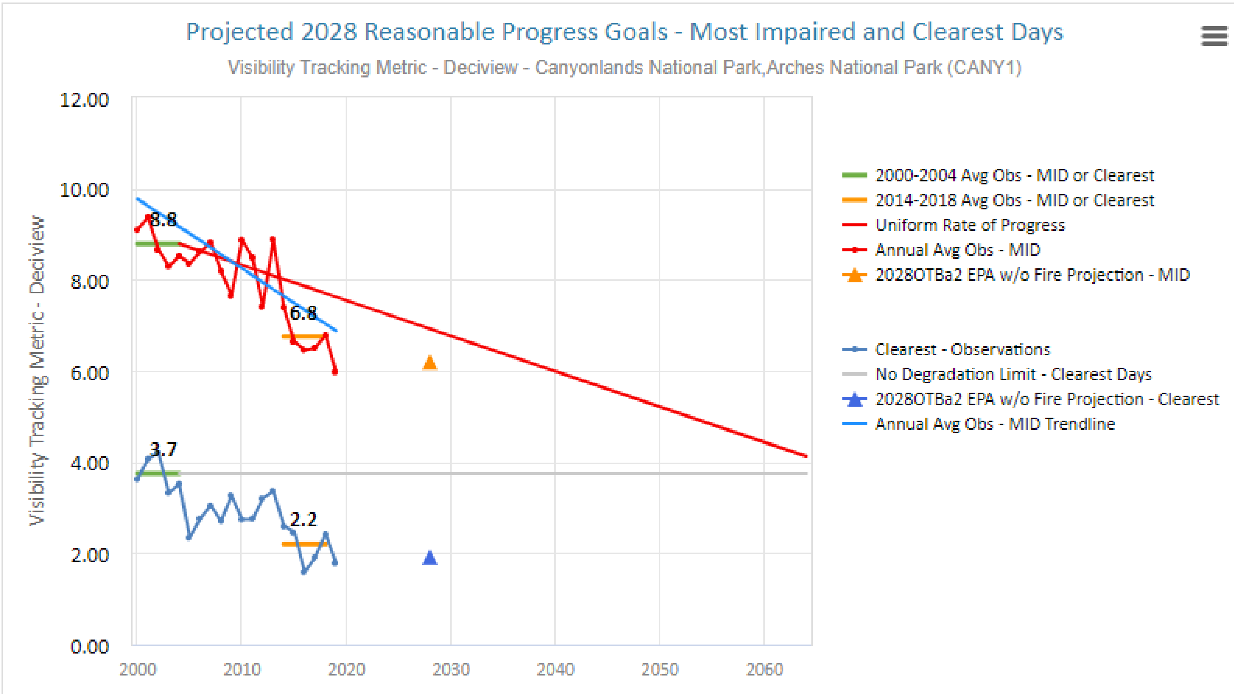

Figure 64: Example of projected RPGs for Canyonlands and Arches CIAs

Finally, this approach provides regulatory flexibility for PacifiCorp, which can meet the mass-based emission limits either by limiting or otherwise modifying operation, installing controls, switching fuels, closing units, or some combination of these options. Refer to section 8.D.3 for UDAQ's reasonable progress determinations for the Hunter and Huntington power plants.

7.C.4 Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility Four-Factor Analysis Summary and Evaluation[175]

Facility Identification

Name: Sunnyside Cogeneration Facility
Address: State Road 123, #1 Power Plant Road, Sunnyside, Utah
Owner/Operator: Sunnyside Cogeneration Associates
UTM coordinates: 552,984 m Easting, 4,377,786 m Northing, UTM Zone 12

Facility Process Summary

The Sunnyside Cogeneration Facility (Sunnyside) is in Sunnyside, Carbon County, Utah (approximately 25 miles southeast of Price). The nearest Class I areas and their respective distance from the facility are Canyonlands National Park, (91 miles), Capitol Reef National Park (95 miles), Bryce Canyon National Park (171 miles) and Zion National Park (217 miles). The Sunnyside power plant began operations in May of 1993. The electricity it produces is sold to PacifiCorp, operating as Utah Power and Light [UPLC). The plant qualifies as a small power production facility and qualifying cogeneration facility ("QF") under the Public Utility Regulatory

[175] Sunnyside's full four-factor analysis can be found in appendix C.4.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008928.pdf

Policy Act of 1997 (‘PURPA”). The facility operates a coal-fired combustion boiler that features circulating fluidized bed (CFB), a baghouse and a limestone injection system. The facility also operates an emergency diesel engine and emergency generator. All process units are currently permitted in its UDAQ Title V air operating permit (Permit # 700030004) which was renewed on April 30, 2018. The CFB boiler is subject to the NESHAPS Part 63, Subpart UUUUU Mercury and Air Toxics Standards [MATSI Rule. As a result, Sunnyside is required to meet a standard of 0.2 lb./MMBtu of SO_2.

This standard requires continuous monitoring with a continuous emission monitor system (CEMS). The plant’s CFB boiler, designed by Tampella Power, produces steam that drives a Dresser Rand turbine generator. The CFB boiler and baghouse uses limestone injection. Historically, CFB boilers have been one of the primary low emission combustion technologies for commercial and small utility installations using low grade fuels. This trend continues with CFB technology being considered for smaller coal fired units as a means to effectively utilize lower quality fuels and meet environmental requirements. The current boiler produces emissions from one stack at Sunnyside’s cogeneration facility. For the purposes of a control technology review, only the emissions from the boiler stack itself are considered as well as the operations from the emergency diesel engine and emergency generator.

Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Circulating Fluidized Bed Combustion Boiler – Rated at 700 MMBtu/hr and fueled by coal, coal refuse or alternative fuels, and fueled by diesel fuel during startup, shutdown, upset condition and flame stabilization. This boiler is equipped with a limestone injection system to the fluidized bed and a baghouse. This boiler is subject to 40 CFR 60, Subpart Da and CAM.
- One diesel engine, approximately 201 HP, used to power the emergency backup fire pump, and various portable I/C engines to power air compressors, generators, welders and pumps.
- A 500-kW emergency standby diesel generator, used in the event of disruption of normal electrical power and testing/maintenance. 1.4 Facility Current Potential to Emit The current PTE values for Sunnyside, as established by the most recent NSR permit issued to the source (DAQE-AN100960029-13) are as follows (in tons/year): SO_2 1,289.26 NO_x 771.2.

Facility Current Potential to Emit

The current PTE values for Sunnyside, as established by the most recent NSR permit issued to the source (DAQE-AN100960029-13) are as follows:

Table 62: Sunnyside: Current Potential to Emit (Tons/Year)

Pollutant	Potential to Emit (tons/yr)
SO_2	1,289.26
NO_x	771.2

Sunnyside Four Factor Analysis Conclusion

The facility currently uses CFB technology to lower NO_x emissions and achieves Title V permitting NO_x limits as currently operated. SCR is a technically feasible control option for this boiler but is not cost effective with a control cost greater than $10,000 per ton of NO_x removed. While SNCR may represent a cost-effective option for NO_x emissions reduction, the introduction of substantial ammonia slip has the potential to cause adverse environmental impacts. The ammonia and $PM_{2.5}$ emissions have the potential to cause direct health impacts for those in the area, and present additional safety concerns for the storage and transportation of ammonia. Despite not having SNCR or SCR installed, the Sunnyside boiler is achieving a NO_x emission rate on a lb./MMBtu basis that is comparable to PSD BACT levels set on CFB boilers. Therefore, additional add-on controls for NO_x emissions reductions are not necessary on the Sunnyside CFB boiler.

UDAQ Evaluation Summary and Conclusion[176]

UDAQ noted several potential errors in Sunnyside's analysis:

1. The Sunnyside four-factor analysis for SO_2 eliminated both wet scrubbers and spray dry scrubbers from consideration as an SO_2 control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber.
2. Sunnyside Cogen did not provide justification for including the cost for a new replacement baghouse with a dry scrubbing option.
3. Sunnyside's analysis was inconsistent regarding the amount of sorbent required and the possible resulting efficiency.
4. The Sunnyside dry sorbent injection analysis assumed too high of a cost for auxiliary power.
5. The Sunnyside dry scrubbing cost analysis improperly included annual costs for taxes and insurance and assumed unreasonably high annual costs for administrative charges.
6. The Sunnyside dry scrubbing cost analysis improperly assumed a 30% increase in cost as a retrofit factor.
7. The Sunnyside dry sorbent injection cost analysis used too high of an interest rate and too short expected life when amortizing costs.
8. Sunnyside assumed too high of an interest rate and too short of a life of controls in determining the annualized capital costs of SNCR and SCR The Sunnyside SCR and SNCR cost effectiveness analyses assumed a 4.75% interest rate and a 20- year life of both SCR and SNCR.
9. Sunnyside assumed a very high cost for aqueous ammonia that was not justified. In its SNCR and SCR cost analyses, Sunnyside Cogen assumed a cost for 29.4% aqueous ammonia of $2.50 per gallon.

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[176] UDAQ's full evaluation of Sunnyside's four-factor analysis submittal can be found in appendix C.4.B or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009630.pdf

10. Sunnyside assumed a higher cost for electricity than it assumed in its dry sorbent injection analysis in its SCR and SNCR cost analysis.

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four Factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR. A. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR. A. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Any other pertinent information Sunnyside feels is warranted should also be provided in order to assist UDAQ in the review process.

Sunnyside's Evaluation Response[177]

1. HAR technology is not feasible as flue gas exiting the CFB boiler at Sunnyside typically contains approximately 10% unreacted calcium oxide in the in the fly ash and even less in the bottom ash.[178] Additionally, there is a significant amount of ash already entrained in the CFB boiler which would make additional ash infeasible. SDA technology requires significant amounts of water that Sunnyside is unable to adequately source, thus they find it infeasible. Given the configuration of existing units, there is not enough space between the CFB boiler and existing baghouse for the addition of a further CDS/CFBS unit without significant reconfiguration of existing equipment. Of all the add on control technologies considered, CDS/CFBS is the only potentially feasible option. Existing controls for SO_2 as defined in Sunnyside's Title V air operation permit (#700030004) Condition II.A.2 currently provide SO_2 controls to the circulating fluidized bed (CFB) boiler, which involves limestone injection.
2. Sunnyside included a cost analysis for a CDS/CFBS as per UDAQ request as it is the only technically feasible add-on unit. However, the average estimated cost for a CDS/CFBS able to achieve 90% SO_2 control ranges from $81 to $400 million plus another $1.7 million for a new baghouse required with this technology. Ash Grove does not consider this device economically feasible.
3. Sunnyside has updated this formula in the revised cost analysis to utilize the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler. This formula now assumes that use of lime could achieve 74% SO_2 reduction resulting in a lime injection rate of 0.0921 tons per hour or 184 lb/hour.
4. Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ comments. Specifically, the busbar cost for electricity has now been calculated based on

[177] Sunnyside's full evaluation response can be found in appendix C.4.C or at: https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2021-017202.pdf
[178] Based on fly ash characterization results conducted at Sunnyside Cogeneration Associates.

2018 operating data. The resulting rate is $49.45 per MW. Additionally, the electrical usage rate has been updated to match the UDAQ comments and as displayed below: 0.028% x 58.33 MW x 8031 hours/yr x $49.45/MW-hr = $6,486 per year.

The analysis provided under Question 2, 3, and 4 along with the attached cost analysis should replace information found in Sections 5.4 and 5.5 of the Four Factor Analysis.

5. The UDAQ suggested that there are tax exemptions in Utah for control equipment. UAC R307-120 exempts the purchase of control equipment from sales/use tax. As a result, sales tax is no longer included in CDS/CFBS cost analysis provided. Sales tax rates and property taxes are not used in either the SCR or SNCR cost analyses due to the equation format provided by EPA. Insurance rate was based on a 1% of the Total capital investment (TCI) which is documented in the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs. The administrative cost calculation has been updated to be consistent with SCR as suggested by the UDAQ.
6. The UDAQ questioned the retrofit factor (RF) of 1.3 used all cost analyses, as a result Sunnyside reevaluated the use of this factor on a technology specific basis. Referencing the EPA Control Cost Manual, Sunnyside believes the 1.3 retrofit factor is justified for use in their cost calculations for CDS/CFBS and SCR. They reconsidered their SNCR calculations and instead used a 1.0 retrofit factor.
7. A 20-year life span and 7% interest rate has been applied to the cost control analyses provided by Sunnyside.
8. The equipment life and interest rate explanations provided in Question 7 are not control technology specific. Thus, the same conclusions are applicable, namely, a 20-year life span and 7% interest rate are appropriate for the cost analyses provided.
9. In response to the UDAQ's request, Sunnyside obtained a cost estimate for 19% aqua ammonia from Thatcher Group, Inc (Thatcher). Thatcher quoted $0.18 per lb. of solution. Based on this value, if we assume a density of 19% ammonia is estimated to be 7.46 lbs/gal to 7.99 lbs/gal. This results in a cost per gallon ranges from 1.34 $/gal to 1.438 $/gal. This cost is significantly higher than the EPA estimate of $0.293, which is acceptable as it states, "User should enter actual value if known". Furthermore, it should be noted that the cost for ammonia based on the most recent U.S. Geological Survey, Minerals Commodity Summaries, which was quoted in the original Four Factor Analysis is also significantly higher and based on a density of 29% ammonia. Since the $1.438 is still less than the originally used $2.5 per gallon, these calculations have been updated to include the vendor quote.
10. As discussed in Question 4, Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ's comments. Please see section 4 for additional information. A revised cost analysis for SCR and SNCR have been provided in Attachment A to replace the cost analysis in the original Four Factor Analysis.

UDAQ Response Conclusion

UDAQ agrees with the amendments included in Sunnyside's evaluation response and finds the answer's provided in the facility's response satisfactory. Refer to section 8.D.5 for UDAQ's reasonable progress determinations for the Sunnyside Cogeneration Facility.

7.C.5 US Magnesium LLC- Rowley Plant[179]

Facility Identification

Name: Rowley Plant Address: 12819 North Skull Valley Road 15 Miles North Exit 77, I-80, Rowley, Utah
Owner/Operator: US Magnesium LLC
UTM coordinates: 4,530,490 m Northing, 354,141 m Easting, Zone 12

Facility Process Summary

US Magnesium LLC (USM) operates a primary magnesium production facility at its Rowley Plant, located in Tooele County, Utah. USM produces magnesium metal from the waters of the Great Salt Lake. Some of the water is evaporated in a system of solar evaporation ponds and the resulting brine solution is purified and dried to a powder in spray dryers. The powder is then melted and further purified in the melt reactor before going through an electrolytic process to separate magnesium metal from chlorine. The metal is then refined and/or alloyed and cast into molds. The chlorine from the melt reactor is combusted with natural gas in the chlorine reduction burner (CRB) and converted into hydrochloric acid (HCl). The HCl is removed from the gas stream through a scrubber train. The chlorine that is generated at the electrolytic cells is collected and piped to the chlorine plant where it is liquefied for reuse or sale. USM Rowley Plant is a PSD source for CO, NO_x, PM_{10}, $PM_{2.5}$, and VOCs.

Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Three (3) gas turbines/generators and duct/process burners (natural gas/fuel oil)
- Chlorine reduction burner (CRB), and associated equipment
- Riley Boiler, 60 MMBtu/hr (natural gas)
- Solar pond diesel engines, 30 engines rated between 90 and 420 hp
- Fire pump engine, one additional diesel engine rated at 292 hp

Facility Current Potential to Emit

The current PTE values for the Rowley Plant, as established by the most recent NSR permit issued to the source (DAQE-AN107160050-20) are as follows:

Table 63: Current Potential to Emit

Pollutant	Potential to Emit
SO_2	24.10
NO_x	1,260.99

[179] US Magnesium's full four-factor analysis submittal for the Rowley Plant can be found in appendix C.5.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2020-014024.pdf

US Magnesium Four-Factor Analysis Conclusion

This outlines USM's evaluation of possible retrofit options for all NO_x emitting units onsite at their Rowley Plant located in Tooele County, Utah, in an attempt at reducing their NO_x emissions facility wide and reducing their impact on visibility impairment issues. The results of this report found that it is potentially technologically and economically feasible to install a flue gas recirculation unit on the Riley boiler, reducing their NO_x emissions by an estimated 22.6 tons annually. Aside from this change, there were currently no other technically or economically feasible options available for USM's Rowley Plant. Pending further technological and cost refinement, the implementation schedule for the installation of the FGR unit may be installed prior to the end of 2028. Therefore, the emissions for the 2028 modeling scenario could be an estimated 22.6 tons less than the 2018 baseline year NO_x emissions.

UDAQ Evaluation[180]

Several errors were made during the analysis of the various control options outlined in this document. While the errors ultimately do not change the outcome or results of the analysis, they should be corrected prior to final acceptance by DAQ. The following lists the errors noticed by DAQ and the resulting effect each error leads to in the final result:

Incorrect interest rate used for control cost calculation – rather than using the current bank prime rate of 3.25%, the source calculated all control costs with either an interest rate of 7% (used as the default in the control cost manual) or 5.5% (used as the default in the SCR control cost spreadsheet). Both calculations result in a higher control cost in $/ton. Second, the source used only a 20-year expected life for application of an SCR, which is lower than the standard 30-year lifespan. Again, this would artificially inflate the control cost by increasing the annualized cost. However, the overall cost of the SCR system as estimated by the source was lower than expected, with an initial cost of just $87,000. The low initial cost serves to lower the resulting control cost. DAQ reanalyzed the use of SCR on the Riley Boiler under two different scenarios. Under PTE, assuming full load, the application of SCR might be expected to remove as much as 188 tons of NO_x at a control cost of $4,073/ton of NO_x removed – assuming the same 90% removal efficiency as did the source. However, the Riley Boiler did not operate at that high an output level – reporting just 45.25 tons of actual emissions in 2018. Adjusting the emission reduction for 90% of the actual emissions gives a removal of 40.7 tons of NO_x (as opposed to the 38 tons suggested by the source), at a control cost of $18,800/ton of NO_x removed. Similar errors were made with respect to the FGR calculations on the Riley Boiler. The incorrect interest rate was used – 7% vs 3.25%. FGR systems typically have a potential lifespan of 15 years rather than the 20 years suggested by the source. DAQ recalculated the control costs correcting for these errors and obtained a modified value of 22.5 tons of NO_x removed at a control cost of $1,880/ton of NO_x removed. None of the other equipment requires additional evaluation, as each is currently well controlled. While the same types of errors were

[180] UDAQ's full evaluation of US Magnesium's four-factor analysis submittal can be found in appendix C.5.B or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009628.pdf

made in the source's analysis, the resulting outcomes and conclusions remain unchanged. DAQ recommends that FGR be considered for retrofit control application on the Riley boiler. Should the source increase utilization of the Riley boiler, then the application of SCR should be considered.

US Magnesium's Evaluation Response[181]

US Magnesium re-evaluated the status of the Riley boiler and the Riley boiler NO_x emission factor utilized in US Magnesium's 2018 air emission inventory (AEI) that was the basis for the 4-factor analysis of that unit. In summary, the US Magnesium 2018 AEI grossly overstated the NO_x emissions associated with the Riley boiler in two ways: 1) the Riley boiler is a 60 MMBTU boiler but the AP42 emission factor in the 2018 AEI is for a >100 MMBTU boiler, and 2) the Riley boiler, from the time of its installation, is outfitted with a low NO_x burner, but the AP42 emission factor in the 2018 AEI is for an "uncontrolled burner." The implications are summarized in the table below:

Table 64: US Magnesium's Reevaluation of Riley Boiler Controls

Riley Boiler 2018	NO_x emission factor	AP 42 Table1.4-1. Emission Factors for NO_x and CO from Natural Gas Combustion		Estimated NO_x emissions (TPY)
AEI as submitted	190 lbs./MMscf	>100MMBTU (Large)	Uncontrolled	45.2499
AEI corrected for actual status of Riley boiler	50 lbs./MMscf	<100MMBTU (Small)	Controlled - Low NO_x burner	11.9074

Corrected 2018 NO_x emissions for the Riley boiler, implications on the 4-factor analysis:

- Using the same reductions assumed for FGR (up to 50% NO_x), the estimated reduction would be about 6 tons/year.
- Using the same reductions assumed for SCR (up to 90% NO_x), the estimated reduction would be about 10.7 tons/year.
- Using DAQ's modified calculation for FGR: $1,880/ton * 22.5 tons = $42,000/yr. Correcting to 6 ton/yr reduction = $7,050/ton.
- Using DAQ's modified calculation for SCR: $18,800/ton * 40.7 tons = $765,160/yr. Correcting to 11.9 ton/yr reduction = $64,300/ton.

UDAQ Response Conclusion

UDAQ does not agree with US Magnesium's evaluation response. We do not possess any records of an LNB control on the Riley boiler. Using the original four-factor analysis submittal,

[181] US Magnesium's full evaluation response can be found in appendix C.5.C or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011902.pdf

FGR on the Riley boiler remains a cost-effective and viable control option. UDAQ would require proof of the existence of the LNB and its NO_x removal efficacy before agreeing it is a satisfactory justification for altering the control cost calculations. Refer to section 8.D.6 to review UDAQ's reasonable progress and controls determination for the Rowley Plant.

Chapter 8: Determination of Reasonable Progress Goals

8.A Reasonable Progress Requirements

The RHR requires Utah to submit a long-term strategy (LTS) that includes measures necessary to achieve the Reasonable Progress Goals (RPGs) in each CIA. This strategy must consider major and minor stationary sources, mobile sources, and area sources. Section 169A (a)(4) and other subsections of the Clean Air Act call for reasonable progress "toward meeting the national goal" of eliminating anthropogenic (manmade) impairment of visibility. Utah is required under the RHR to establish visibility deciview goals for each of its five CIAs that allow them to meet the RPGs towards natural visibility by 2064. RPGs are interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions and are developed in consultation with FLMs and nearby affected states. In determining the criteria for reasonable progress, Utah was required under Section 169A(g) of the CAA to consider four factors: cost of compliance, the time necessary for compliance, energy and non-air environmental impacts of compliance, and the remaining useful life of existing sources that contribute to visibility impairment.[182]

8.B. Regional Modeling of the LTS to set RPGs

The RHR requires states to demonstrate progress every ten years toward the CAA goal of no manmade visibility impairment. WRAP conducted the modeling necessary to track this progress for Utah. EPA guidance for tracking visibility progress[183] defines a visibility impairment tracking metric (measured in deciviews) using observations from the IMPROVE monitoring network sites that represent CIAs. EPA defined in the RHR and guidance a Uniform Rate of Progress (URP) glidepath for the 20% most impaired days as the straight line from the 2000-2004 IMPROVE 5-year average baseline to EPA estimates of future natural visibility conditions, plotted for 2064. In the first regional haze planning period, 2000-2018, EPA guidance[184] defined most impaired days as those days with highest total haze. States were required to demonstrate visibility progress by 2018 compared to the URP glidepath for the haziest days and no degradation of visibility on the clearest days from the 2000-2004 IMPROVE 5-year average baseline. Visibility on the clearest days improved between 2000 and 2018 across the Class I areas in the western U.S. However,

[182] *See* 42 USC § 7492(g)(1).
[183] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf
[184] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

smoke from wildfire and wildland prescribed fire events and dust events on the haziest days made tracking the visibility benefits due to reducing U.S. anthropogenic emissions more difficult.

For the second regional haze implementation period, 2018-2028, states are required to demonstrate visibility progress by 2028 for the most impaired days and no visibility degradation for the clearest days. EPA guidance[185] defined most impaired days as those days with the highest fractional contribution to aerosol light extinction from anthropogenic sources. EPA statistical methods use IMPROVE measurements of carbon and crustal materials to separate contributions from episodic extreme natural events (e.g., wildfire or dust) from routine natural and anthropogenic contributions. Ammonium sulfate and ammonium nitrate are assigned primarily to anthropogenic emissions with smaller contributions from routine natural sources. This statistical approach does not separate contributions due to U.S. anthropogenic emissions from those of international anthropogenic emissions. Since states do not have authority to reduce international emissions, WRAP conducted source apportionment modeling analyses to evaluate U.S. anthropogenic contributions to haze and progress in reducing U.S. anthropogenic contributions to haze over time.

8.C URP Glidepath Checks[186]

These charts illustrate the Uniform Rate of Progress (URP) Glidepath, as defined by EPA guidance,[187] compared to IMPROVE measurements for the period 2000-2018. The URP glidepath is constructed (in deciviews) for the 20% most impaired days (MID) or clearest days using observations from the IMPROVE monitoring site representing a Class I area. The URP glidepath starts with the IMPROVE MID for the 2000-2004 5-year baseline and draws a straight line to estimated natural conditions in 2064. For clearest days, the goal is no degradation of visibility from the 2000-2004 5-year baseline, therefore glidepath for clearest days is a straight line from the 2000-2004 baseline to 2064. In the second regional haze planning period, 2064 natural conditions estimates are the same as the 15-year average of natural conditions on most impaired days or clearest days in each year 2000-2014. IMPROVE annual average values are presented as points. IMPROVE 5-year average values are presented as solid lines covering the periods 2000-2004 and 2014-2018.

The 2028 On the Books (2028OTBa2) visibility projection in deciviews is illustrated as a point that can be compared to the Uniform Rate of Progress glidepath. UDAQ has chosen the "2028OTBa2 w/o fire" projection that excludes wildfire from MID to more accurately represent future emissions from sources UDAQ is better able to control. This projection reduces the impact of elemental carbon and organic carbon from fires from the original 2028 EPA projection to remove additional fire impacts that were not fully eliminated by the move from haziest days metric (used during the first planning period) to most impaired days metric (used during the

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[185] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf
[186] 40 C.F.R. § 51.308(f)(3)(i)
[187] The EPA Guidance for Tracking Progress Under the Regional Haze Rule can be found at https://www.epa.gov/sites/default/files/2021-03/documents/tracking.pdf

second planning period). The 2028OTBa2 visibility projection reflects Utah's LTS, including the results of the reasonable progress determinations found in 8.D, with the exception of the anticipated 22.5 tons of NO_x emissions reductions associated with the installation of FGR controls on the Riley Boiler at U.S. Magnesium's Rowley Plant. However, the resulting reduction in NO_x emissions is a small percentage of Utah's total 2028 NO_x emissions. The 2028OTBa2 visibility projection includes emissions from the now-closed Kennecott Power Plant, which was projected to have 1,152 tons of NO_x, 2,152 tons of SO_2, and 135 tons of $PM_{2.5}$ emissions in 2028. The 2028 projections also include emissions from the Tesoro Refinery not accounting for the refinery's recent PM2.5 SIP BACT analysis which resulted in an annual mass-based SO_2 limit and an estimated 408-ton SO_2 reduction. The omission of these emissions reductions in the 2028OTBa2 projection make our glidepath comparisons conservative, as actual 2028 visibility can be expected to improve due to lower emissions levels. Refer to section 6.A.10 to review Utah's Long-Term Strategy and additional details on the emissions reductions UDAQ is relying on to make reasonable progress in the second implementation period.

8.C.1 Bryce Canyon National Park

The 2000-2004 URP baseline in Bryce Canyon for MID is 8.4 dv. The 2014-2018 average observations for MID is 6.6, meaning visual range on the most impaired days has increased from 104.62 miles to 125.26 miles, an improvement of 20.64 miles. The projected visibility in 2028 without fire impacts is 6 dv, which, represented by the orange triangle on the graph, is below the URP glidepath. For clearest days, the 2000-2004 baseline for Bryce Canyon is 2.8 dv. The 2014-2018 average observations for clearest days are 1.5 dv meaning that visual range on the clearest days has increased from 183.16 miles to 208.59 miles, an increase of 25.43 miles.

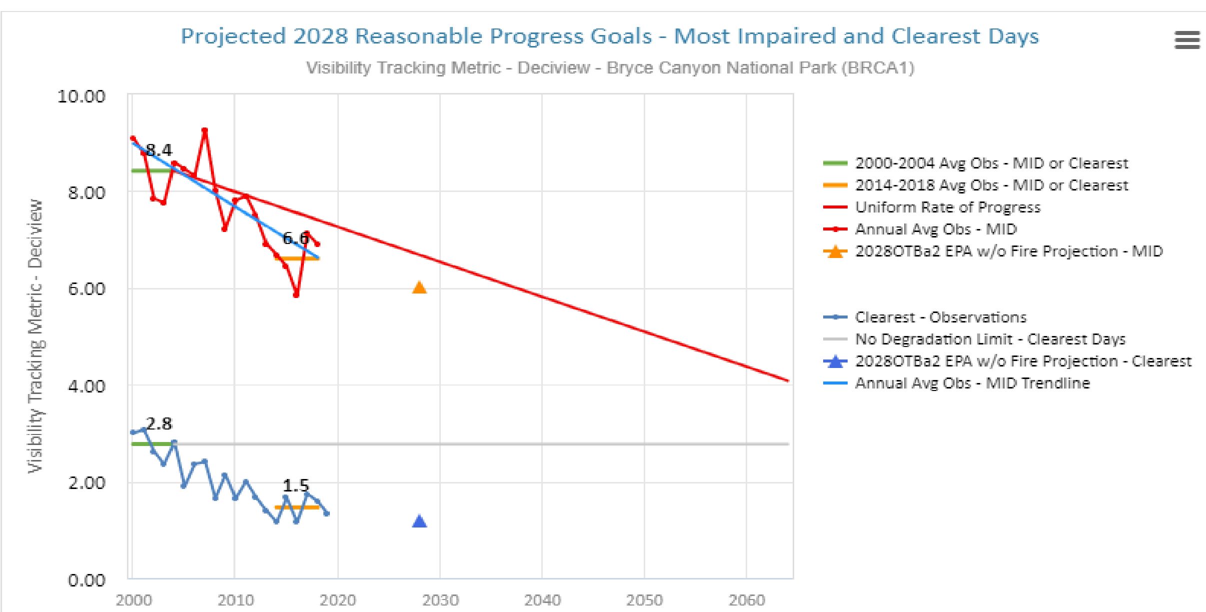

Figure 65: Projected 2028 RPG Bryce Canyon National Park

The projected 2028 visibility on clearest days is 1.2 dv, which, represented by the blue triangle, is below the no degradation limit for clearest days.

8.C.2 Canyonlands and Arches National Park

The 2000-2004 URP baseline in Canyonlands and Arches National Park for MID is 8.8 dv. The 2014-2018 average observations for MID is 6.8, meaning visual range on the most impaired days has increased from 100.52 miles to 122.78 miles, an improvement of 22.26 miles. The projected visibility for MID in 2028 without fire impacts is 6.2 dv, which is below the URP glidepath. For clearest days, the 2000-2004 baseline for Canyonlands and Arches is 3.7 dv. The 2014-2018 average observations for clearest days are 2.2 dv meaning that visual range on the clearest days has increased from 167.40 miles to 194.49 miles, an increase of 27.09 miles. The projected 2028 visibility on clearest days is 1.9 dv, which is also below the no degradation limit for clearest days.

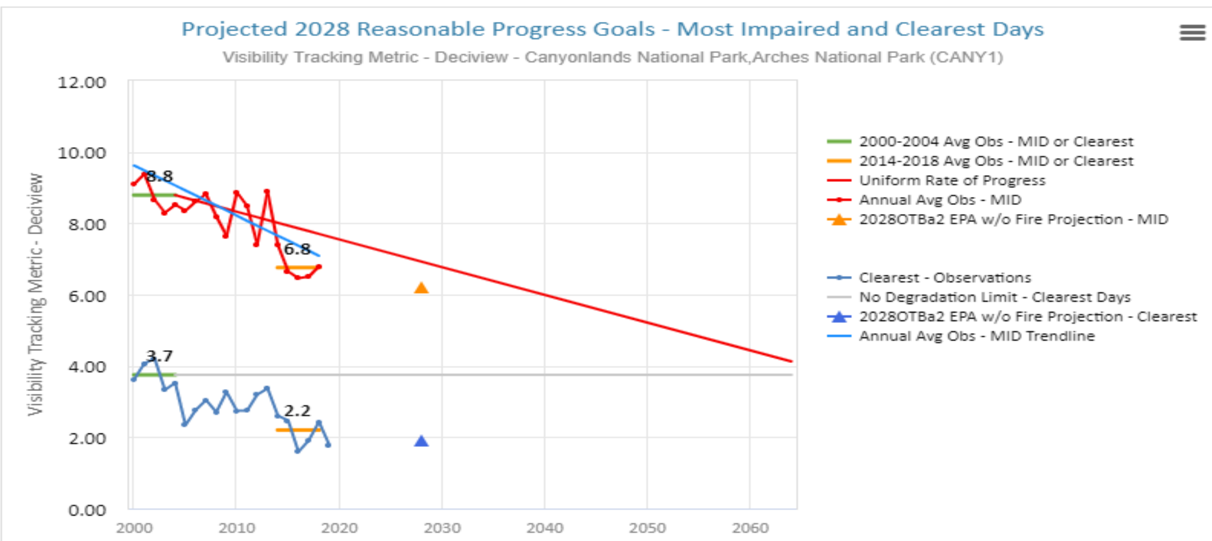

Figure 66: Projected 2028 RPG Canyonlands and Arches National Parks

8.C.3 Capitol Reef National Park

The 2000-2004 URP baseline in Capitol Reef for MID is 8.8 dv. The 2014-2018 average observations for MID is 7.2, meaning visual range on the most impaired days has increased from 100.52 miles to 117.96 miles, an improvement of 17.44 miles. The projected visibility for MID in 2028 without fire impacts is 6.6 dv, which is below the URP glidepath. For clearest days, the 2000-2004 baseline for Capitol Reef is 4.1 dv. The 2014-2018 average observations for clearest days are 2.4 dv meaning that visual range on the clearest days has increased from 160.83 miles to 190.64 miles, an increase of 29.81 miles. The projected 2028 visibility on clearest days is 2.1 dv, which is below Capitol Reef's no degradation limit for clearest days.

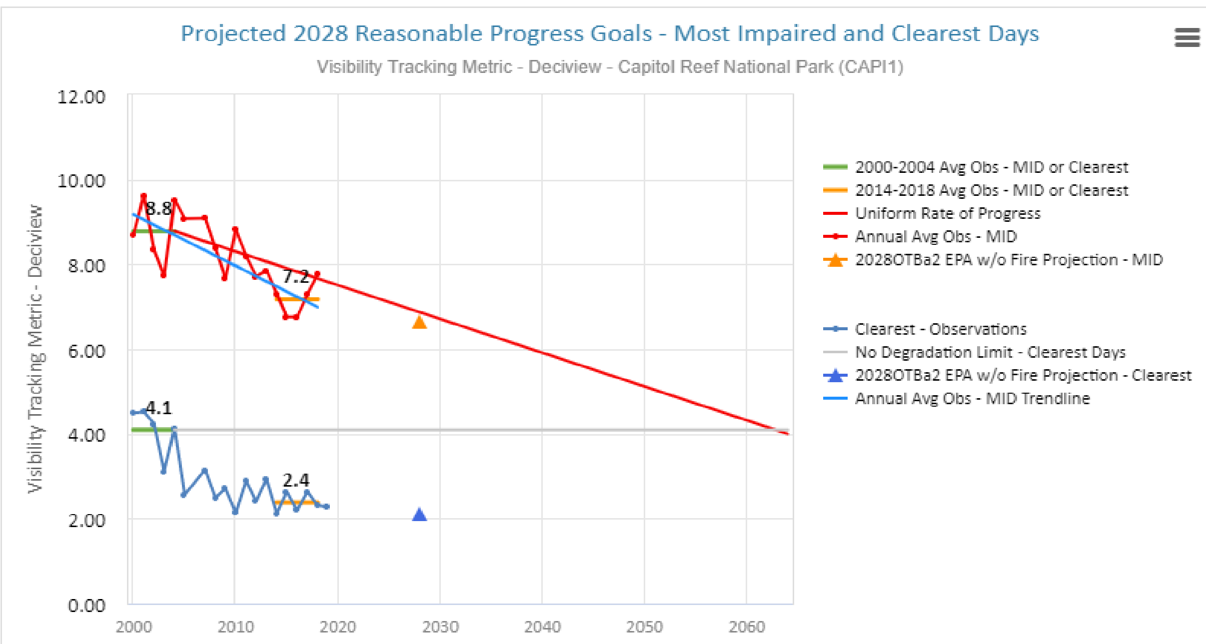

Figure 67: Projected 2028 RPG Capitol Reef National Park

8.C.4 Zion National Park

The 2000-2004 URP baseline in Zion National Park for MID is 10.4 dv. The 2014-2018 average observations for MID is 8.7, meaning visual range on the most impaired days has increased from 85.66 miles to 101.53 miles, an improvement of 15.87 miles. The projected visibility for MID in 2028 without fire impacts is 8.3 dv, which is below the URP glidepath. For Zion's clearest days, the 2000-2004 baseline for is 4.5 dv. The 2014-2018 average observations for clearest days are 3.9 dv meaning that visual range on the clearest days has increased from 154.53 miles to 164.08 miles, an increase of 9.55 miles. The projected 2028 visibility on clearest days is 3.5 dv, which is below the no degradation limit for clearest days in Zion.

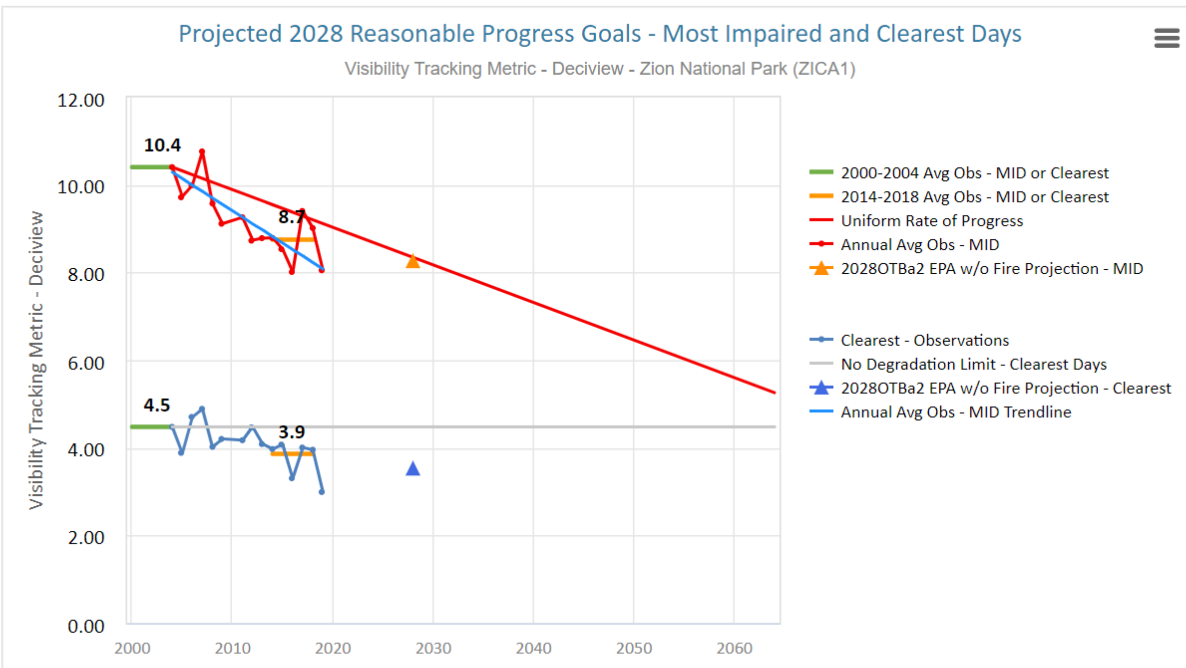

Figure 68: Projected 2028 RPG Zion National Park

8.C.5 Summary of URP Glidepaths

The table below summarizes the information from Figures 65-68 above, comparing visibility on the most impaired and clearest days for the baseline, 2028 URP, and 2028 EPA w/o fire projection values for each of Utah's CIAs in addition to stating whether the CIA is below the URP glidepath and no degradation line.

Table 65: Comparison of baseline, 2028 URP, 2028 EPA w/o fire projection for worst and clearest days

CIA IMPROVE Site	WORST DAYS					CLEAREST DAYS			
	Baseline (dv)	2028 URP (dv)	2028 EPA w/o Fire Projection (dv)	% Progress to 2028 URP	2028 Below URP Glidepath? (Y/N)	Baseline (dv)	2028 EPA Projection (dv)	2028 EPA w/o Fire Projection (dv)	2028 Below No Degradation Line? (Y/N)
BRCA1	8.42	6.68	6.03	137.60%	YES	2.77	1.22	1.20	YES
CANY1	8.79	6.92	6.19	139.10%	YES	3.75	1.94	1.92	YES
CAPI1	8.78	6.87	6.63	112.28%	YES	4.10	2.17	2.10	YES
ZICA1	10.40	8.35	8.27	103.73%	YES	4.48	3.65	3.54	YES

8.D Reasonable Progress Determinations

The following sections contain UDAQ's determinations on what controls are necessary for Utah's CIAs to make reasonable progress in this implementation period. UDAQ believes these determinations will help protect reasonable further progress demonstration and visibility in Utah. All emissions limits, operating procedures, and compliance strategies for the following reasonable progress determinations which limit NO_x, SO_2, and PM are identified in SIP Subsection IX.H.21 and 23, which are made enforceable through EPA approval and incorporation into the Utah Air Quality Rules.

8.D.1 Reasonable Progress Determination for Ash Grove Cement Company – Leamington Cement Plant

Upon reviewing Ash Grove's four-factor analysis for the Leamington Cement Plant and their evaluation response, UDAQ finds that it is adequately controlled for the purposes of the Second Implementation Period. UDAQ has determined that the existing SCNR control and emissions limits for the Leamington Cement Plant are effective measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning. The Leamington Cement Plant's existing controls and emissions limits will be implemented and enforced through SIP Subsection IX.H.23 to ensure the plant will continue to implement existing measures and will not increase its emission rate. Refer to section 7.B.3 to review the four-factor analysis and evaluation response results for the Leamington Cement Plant.

8.D.2 Reasonable Progress Determination for Graymont Western US Incorporated – Cricket Mountain Plant

Upon reviewing the Graymont Western US Inc. four-factor analysis for their Cricket Mountain Plant and their evaluation response, UDAQ finds that additional controls are not required for reasonable progress in this implementation period based on their cost/ton and the potential proprietary costs of SNCR technology for the kilns. UDAQ has determined that the existing controls and emissions limits for the Cricket Mountain Plant are effective measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning. The Cricket Mountain Plant's controls and emissions limits will be implemented and enforced through SIP Subsection IX.H.23 to ensure the plant will continue to implement existing measures and will not increase its emission rate. Refer to section 7.B.4 to review the four-factor analysis and evaluation response results for the Cricket Mountain Plant.

8.D.3 Reasonable Progress Determination for PacifiCorp: Hunter and Huntington Power Plants

Upon reviewing PacifiCorp's four-factor analysis and evaluation response, UDAQ is establishing plantwide annual mass-based NO_x emission limits. At the resulting utilization and emissions levels, UDAQ finds SNCR and SCR not to be cost-effective. UDAQ is also adding PacifiCorp's existing SO_2 emission limits from their Title V permit for all five units to ensure federal enforceability in the regional haze context. These emission limits are to be implemented and enforced through SIP Subsection IX.H.23. Please refer to section 7.C.3 to view PacifiCorp's and UDAQ's complete analysis and conclusions.

8.D.4 Reasonable Progress Determination for Sunnyside Cogeneration Associated – Sunnyside Cogeneration Facility

Upon reviewing the Sunnyside Cogeneration Associated four-factor analysis and evaluation response containing corrections to their analysis of the Sunnyside Cogeneration Facility, UDAQ has found no cost-efficient control options for the facility for the purposes of the Second Implementation Period. UDAQ has determined that the existing controls and emissions limits for the Sunnyside Cogeneration Facility are effective measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning. The Sunnyside Cogeneration Facility's controls and emissions limits will be implemented and enforced through SIP Subsection IX.H.23 to ensure the facility will continue to implement existing measures and will not increase its emission rate. Refer to section 7.B.6 to review the four-factor analysis and evaluation response results for the Sunnyside Power Plant.

8.D.5 Reasonable Progress Determination for US Magnesium LLC – Rowley Plant

Upon reviewing US Magnesium LLC's four factor analysis for their Rowley Plant, UDAQ does not agree with its assessment of an LNB on the Riley Boiler. UDAQ has no record of the existence of an LNB on this unit or it's NO_x reducing efficacy. UDAQ therefore refers to US Magnesium's original four-factor analysis submittal information suggesting that FGR is a cost-effective and viable control option for the Riley Boiler. UDAQ recommends the installation of

FGR on the Riley Boiler to ensure that Utah makes reasonable progress in this implementation period. UDAQ has also determined that the existing controls and emissions limits for the Rowley Plant are measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning to ensure the plant will continue to implement existing measures and will not increase its emission rate. Implementation of these control determinations are to be enforced through SIP Subsection IX.H.23. Refer to section 7.B.7 to review the four-factor analysis and evaluation response results for the Rowley Plant.

8.D.6 Intermountain Power Service Corporation – Intermountain Generation Station

As discussed in section 7.A.2, the planned replacement of the IGS coal-fired units with an EPS-compliant combined-cycle natural gas plant is expected to dramatically decrease regional haze-causing pollutants (PM, SO_2, and NO_x). Though the coal-fire units are expected to cease operation by mid-2025, UDAQ has established a firm closure date of no later than December 31, 2027 to ensure that the coal-fired units at IGS will not continue operation beyond the conclusion of the second implementation period while allowing flexibility for closing the plant in addition to rescinding its permit and approval order. UDAQ has also determined that the existing controls and emissions limits for IGS are measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning to ensure the plant will continue to implement existing measures and will not increase its emission rate. The implementation of the IGS closure and its existing control measures are to be enforced through SIP Subsection IX.H.23.

Chapter 9: Consultation, Public Review, Commitment to further Planning

9.A Federal requirements

In developing each reasonable progress goal, Utah must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in CIAs within Utah.[188] Where the State has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another State, Utah must consult with the other State(s) in order to develop coordinated emission management strategies.[189] Utah must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement and document all substantive interstate consultations.[190] Utah must also provide the FLMs with an opportunity for consultation no less than 60 days prior to the SIP public hearing or public commenting opportunity.[191] This consultation must include the opportunity for FLMs to discuss their assessment of the visibility impairment at CIAs and their recommendations on the development and implementation of strategies to address visibility impairment.[192] Utah must include a description in their implementation period of how it addressed any comment provided by FLMs.[193]

9.B Interstate Consultation

Throughout the second implementation period, Utah has met regularly with its surrounding states. Utah also participates in WESTAR Planning Committee and Four Corners meetings for state RH planning coordination. Table 66 includes a summary of interstate meetings UDAQ took part of. See Appendix B for further documentation of interstate consultation and agreements. UDAQ conducted further consultation and SIP review of the second implementation period status of the non-Utah sources identified in UDAQ's WEP analysis and included this information in Table 67 to Table 68. As shown, all out-of-state sources identified by UDAQ's WEP analysis of Utah's CIAs are either:

- outside state jurisdiction,
- have Q/d values too low to be screened in by the state,
- were screened out due to effective Round 1 BACT controls, or
- are subject to controls or closure in this implementation period.

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[188] *See* 40 CFR § 51.308 (d)(1)(iv)
[189] *See id*., § 51.308 (d)(3)(i)
[190] *See id*., § 51.308 (f)(2)(ii)(C)
[191] *See id*., § 51.308 (i)(ii)(2)
[192] *See id*., § 51.308 (i)(ii)(2)
[193] *See id*., § 51.308 (i)(4)

Table 66: Summary of Interstate Meetings with UDAQ

Date	Time	Entity	Topic	Result
4/28/2021	10-11a	Wyoming	Wyoming and Utah Regional Haze Second Planning Period Update	Debrief after PacifiCorp meeting. Shared draft Montana SIP with Wyoming. They shared their draft SIP with us. We offered ours as soon as it is more complete.
4/30/2021	1-2:30p	Four Corners States	Regional Haze Consultations	Four corners states do not expect to require other states to enforce controls for emissions affecting their Class I Areas. NM discussed in length where they are in their SIP writing process.
5/5/2021	9-9:30a	Wyoming	WY-UT RH Coordination Call	Discussion emissions affecting the other state.
5/5/2021	2-4p	WESTAR	Regional Haze Results Meeting #9	Discussion of different modeling resources available and uses.
5/6/2021	2-3p	WESTAR	WESTAR Planning Committee Call	RH updates and deadline considerations.
5/12/2021	2:30-3:30p	New Mexico	NM-UT DEQ Regional Haze Consultation	NM described their SIP writing process and showed us the modeling tools they plan to use for the out of state emissions section. We offered to exchange draft SIPs.
6/1/2021	1:30-2p	Colorado	CO-UT Regional Haze Consultation	Discussed controls implementation.
9/9/2021	12-12:30p	Arizona	UT-AZ RH Consultation	Neither state is looking for additional controls in the other. Consulted about interest rates and control cost thresholds.
9/9/2021	2-3:30p	WESTAR	State-Only RH Call	
10/15/2021	10-11a	New Mexico (Mark Jones)	Control Cost Consultation	Discussed control cost thresholds and justification.
11/04/2021	2-3p	WESTAR	Planning Committee Meeting	Discussed RH updates and interstate consultation documentation emails.
11/08/2021	1-2p	Wyoming	RH Controls Implementation Consultation	Discussed sources and controls implementation.
11/15-16,2021	10a-4p	4 Corners	Annual AQ Meeting	Participated in giving RH updates with other 4 corners states.
1/7/22	10-11a	New Mexico	WEP Analysis Consultation	Discussed WEP analysis methodologies and CAMx photochemical low-level source apportionment.
1/13/22	1:30-3p	WVPPI	Western Visibility Protection and Planning Initiative	Discussion of the key components of Section 169a of the CAA.
2/10/22	1:30-3p	WVPPI	Western Visibility Protection and Planning Initiative	Discussed, RH history, the relationship between reasonable progress and long-term strategies. Utah volunteered to help plan an in-person meeting between states, FLMs, and EPA.
2/24/22	1-2p	RHPWG	Regional Haze Planning Work Group	Discussed the NGO actions letter submitted to EPA and 60-day notice to file suit.
3/3/22	2-3p	WESTAR	Planning Committee	Discussed RH updates.
3/10/22	1:30-3p	WVPPI	Western Visibility Protection and Planning Initiative	States discussed reasonable progress and long-term strategies.
4/5-4/7/22	8a-5p	WESTAR/WRAP	Spring Meeting	States presented on air quality, visibility, and wildfire modeling and updates.
4/13/22	1:30-3p	WVPPI	Western Visibility Protection and Planning Initiative	States discussed how reasonable progress can be determined and challenges faced by states whose largest sources of impairment are not anthropogenic sources.
4/14/22	2-3p	WESTAR	Planning Committee	States gave RH updates.
5/5/22	2-3p	WESTAR	Planning Committee	States discussed visibility modeling strategies

5/12/22	1:30-3p	WVPPI	Western Visibility Protection and Planning Initiative	States discussed how to incorporate EJ into RH planning.
6/9/22	2-3p	WESTAR	Planning Committee	States were updated by the WRAP work groups.
6/16/22	2-3:30p	WVPPI	Western Visibility Protection and Planning Initiative	States discussed challenges with incorporating EJ into RH planning due to a lack of guidance on how to address or make decisions considering EJ in visibility standards for CIAs.
6/21/22	Various	CA, CO, NM, and NV	RH SIP Controls	UDAQ corresponded with neighbor states inquiring the controls status of non-UT sources ranking in WEP analysis for UT CIAs.

Table 67: Second Implementation Period Status of Non-Utah Sources Identified in NO_3 WEP Analysis

Facility Name	Source State	Utah CIA	WEP NOx Rank	NOx Q/d	WEP_NO3 (% of total)	Four-Factor Analysis? (Y/N)	Proposed Controls	Notes
Bonanza	TR	**CANY1**	3	30.8	59,301.8 (6.4%)	N		Likely closure in 2030 due to settlement
McCarran Intl	NV	**ZICA1**	3	11.1	9,235.4 (3.7%)	N		Majority of NOX emissions from non-road sources (aircraft take-offs and landings)
PNM - San Juan Generating Station	NM	**CANY1**	4	33.7	47,113.4 (5.1%)	Y	TBD, NM has not finalized their second implementation period draft	Subject to four-factor analysis in NM's draft SIP. PNM has announced plant closure in 2022
Four Corners Power Plant	TR	**CANY1**	6	17.8	24,859.3 (2.7%)	N		APS has announced plant closure in 2031
Pg&E Topock Compressor Station	CA	**ZICA1**	6	3.2	7,620.0 (3.1%)	N		Not subject to four-factor analysis in CA's proposed SIP due to low NOx Q/d
Chaco Gas Plant	NM	**CANY1**	8	7.8	14,056.2 (1.5%)	N		Not subject to four-factor analysis in NM's proposed SIP
Bonanza	TR	**CAPI1**	8	21.9	9,450.1 (1.1%)	N		Likely closure in 2030 due to settlement
Lhoist North America and Granite Const. (Apex)	NV	**ZICA1**	9	7.5	7,041.9 (2.8%)	Y	NV proposed SIP requires SNCR on Kilns 1, 3, & 4 as well as LNB on Kiln 1. Kilns 3 & 4 have existing LNBs.	NV's proposed SIP requires SNCR on Kilns 1, 3, & 4 as well as LNB on Kiln 1. Kilns 3 & 4 have existing LNBs.
RED ROCK GATHERING-PREMIER BAR X C.S.	CO	**CANY1**	10	0.6	11,567.0 (1.3%)	N		Not subject to four-factor analysis in CO's proposed SIP due to low NOX Q/d

Table 68: Second Implementation Period Status of Non-Utah Sources Identified in SO_4 WEP Analysis

Facility Name	Source State	Utah CIA	Rank	SO2 Q/d	WEP_SO4 (% of Total)	Four-Factor Analysis Y/N	Proposed New Controls	Notes
CHEMICAL LIME NELSON PLANT	AZ	**BRCA1**	1	8	43,684.7 (21.8%)	N		Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
CHEMICAL LIME NELSON PLANT	AZ	**ZICA1**	1	10.9	38,687.4 (24.8%)	N		Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
ASARCO LLC - HAYDEN SMELTER	AZ	**ZICA1**	3	6	6,672.2 (4.3%)	N		Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
Four Corners Power Plant	TR	**CANY1**	4	11.1	32,557.0 (8.0%)	N		APS has announced plant closure in 2031
CHEMICAL LIME NELSON PLANT	AZ	**CAPI1**	4	5.7	25,448.1 (6.4%)	N		Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
McCarran Intl	NV	**ZICA1**	4	1.2	4,713.6 (3.0%)	N		Majority of NOX emissions from non-road sources

								(aircraft take-offs and landings)
ASARCO LLC - HAYDEN SMELTER	AZ	**BRCA1**	5	5.8	14,391.7 (7.2%)	N		Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
ASARCO LLC - HAYDEN SMELTER	AZ	**CAPI1**	6	5.2	10,351.8 (2.6%)	N		Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
Phoenix Sky Harbor Intl	AZ	**ZICA1**	6	0.6	4,554.6 (2.9%)	N		Majority of NOX emissions from non-road sources (aircraft take-offs and landings)
Four Corners Power Plant	TR	**BRCA1**	7	7.4	5,413.2 (2.7%)	N		APS has announced plant closure in 2031
TUCSON ELECTRIC POWER CO - SPRINGERVILLE	AZ	**CANY1**	7	15.1	13,923.7 (3.4%)	Y	SO2 Limits for Units 1 & 2: a) 16.1 tons SO2/day based on a daily rolling 20-calendar day average. b) 3,729 tons SO2/12-month rolling total	New SO2 limits for units 1 & 2 included in AZ's proposed SIP
California Portland Cement Co.	CA	**ZICA1**	7	2.8	4,038.8 (2.6%)	N		Not subject to four-factor analysis in CA's proposed SIP not required because it is subject to AB 617 which requires local air districts to evaluate large stationary sources to ensure reasonable controls are installed.
CHEMICAL LIME NELSON PLANT	AZ	**CANY1**	8	4.6	13,409.0 (3.3%)	N		Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls
Republic Services Sunrise	NV	**ZICA1**	8	1	4,025.8 (2.6%)	N		Not subject to four-factor analysis in NV's proposed SIP due to low Q/d
TUCSON ELECTRIC POWER CO - SPRINGERVILLE	AZ	**BRCA1**	9	15.4	3,654.7 (1.8%)	Y	SO2 Limits for Units 1 & 2: a) 16.1 tons SO2/day based on a daily rolling 20-calendar day average. b) 3,729 tons SO2/12-month rolling total	New SO2 limits for units 1 & 2 included in AZ's proposed SIP
Bonanza	TR	**CANY1**	9	6.9	11,908.4 (2.9%)	N		Likely closure in 2030 due to settlement
NORTH VALMY GENERATING STATION	NV	**CAPI1**	9	4	5,620.2 (1.4%)	Y	Permanent closure of units 1 and 2 by 12/31/28	NV's proposed SIP includes a federally enforceable closure date of 12/31/28
TUCSON ELECTRIC POWER CO - SPRINGERVILLE	AZ	**ZICA1**	9	14.5	3,447.7 (2.2%)	Y	SO2 Limits for Units 1 & 2: a) 16.1 tons SO2/day based on a daily rolling 20-calendar day average. b) 3,729 tons SO2/12-month rolling total	New SO2 limits for units 1 & 2 included in AZ's proposed SIP

Phoenix Sky Harbor Intl	AZ	**BRCA1**	10	0.6	3,615.9 (1.8%)			Majority of NOX emissions from non-road sources (aircraft take-offs and landings)
PNM - San Juan Generating Station	NM	**CANY1**	10	3.7	10,995.1 (2.7%)	Y		Subject to four-factor analysis in NM's draft SIP. PNM has announced plant closure in 2022
Bonanza	TR	**CAPI1**	10	4.9	4,809.0 (1.2%)			Likely closure in 2030 due to settlement

9.C Documentation of Federal Land Manager consultation and commitment to continuing consultation

UDAQ continuously met with the FLMs throughout the second implementation period planning process. A summary of the meetings UDAQ held with the FLMs is outlined in the table below. UDAQ will continue to consult and collaborate with the FLMs in its future regional haze planning efforts.

Table 69: Summary of FLM Meetings with UDAQ

Date	Time	Entity	Topic	Result
5/5/21	8-9a	Utah DEQ/US Forest Service	Prescribed Fire and Regional Haze	Brief history of Utah's smoke management program and policy regarding it.
5/6/21	1-1:30p	FLM	FLM/UT – Regional Haze Check-In	Updated FLMs on timeline and current RH SIP progress. They informed us on their view that visibility should not be main focus of 2nd planning period and to follow the rule more than the guidance document. They are primarily concerned about 4-factor analyses.
6/22/21	12-12:30p	US Forestry Service - Ples Mcneel	RH update, introductions	Introduction to Ples Mcneel. Wants to be included in updates to FLMs and Paul Corrigan.
10/12/21	12-11a	NPS	Regional Haze Update/Timeline change	Discussed RH SIP draft submittal.
2/9/22	11:30a-1p	NPS	NPS UT Regional Haze Consultation	NPS presented UDAQ with the results of their 60-day review period
2/23/22	11a-12p	USFS – Ples Mcneel and Paul Corrigan	Rx Fire Endpoint Adjustments	Discussed the Rx fire endpoint adjustments available to Utah.
3/13/22	1:04p	NPS	RH Public Comment Schedule	Corresponded via email on the public comment process for UT's RH SIP.
5/2/22	9:56a	NPS	Appendix D.2.C	Provided PDF version of appendix D.2.C via email.
5/3/22	4:20p	NPS	Additional Source Information	Corresponded via email about additional information submittal by Sunnyside and Paradox.
4/21-5/18/22	Various	NPS	Additional Source Information	UDAQ provided additional information provided by Sunnyside, PacifiCorp, and USM via email.
5/16-5/17/22	Various	NPS	Public Comment Hearing	Corresponded via email on the logistics of the RH SIP public hearing.
5/31/22	3:20p	NPS	Public Comment Submittal	NPS provided UDAQ with their comments on the RH SIP.
6/7/22	7:13p	NPS	Additional Source Information	UDAQ provided NPS with comment submittals from Sunnyside and PacifiCorp as well as the link to all public comments.
6/26/22	1:25p	NPS	Additional Source Information	UDAQ provided NPS with an additional information submittals by Sunnyside.

9.C.1 FLM SIP Review[194]

UDAQ submitted its draft RH SIP for the second implementation period to the NPS on December 7th, 2021 and the USFS on December 15th, 2021. On February 14th, NPS and USFS provided UDAQ with their respective SIP reviews which can be found in Appendix D. Documentation of the public notice published by UDAQ on its website from April 25th to June 2nd, 2022 can be found in Appendix F.

9.C.2 NPS Feedback Summary and UDAQ Responses[195]

1. In general, NPS agrees that Utah's source selection process resulted in a reasonable subset of sources to evaluate in the draft SIP. Utah's recommendation to use a lower emission over distance threshold of six versus ten—as recommended by the WRAP—is more rigorous and resulted in a reasonable selection of facilities for evaluation.

2. UDAQ has not identified a cost threshold under which the evaluated controls would be considered reasonable. Many of the controls identified in the four-factor analyses for Utah sources are cost-effective based on cost criteria/thresholds identified by other states. NPS also feels that PacifiCorp should be subject to a higher cost threshold due to their plant's proximity to Utah's CIAs. The SIP should document the full rationale upon which the reasonable progress decisions are based.

   UDAQ Response: UDAQ will not be establishing a control cost threshold at this time. Please refer to chapter 8 for Utah's reasonable progress determinations for the second implementation period and the accompanying justifications, which UDAQ believes are sufficient.

3. NPS recommends that UDAQ require all technically feasible, cost-effective controls identified through four-factor analysis in this planning period.

   UDAQ Response: UDAQ has required all controls it has deemed technically feasible and cost effective. Please refer to the updated part H language in Appendix A to view the enforceable actions resulting from UDAQ's reasonable progress determinations for the purposes of the second implementation period.

4. In the draft SIP UDAQ writes that "Utah has analyzed the WRAP photochemical modeling for OTB 2028 and found that emissions from Utah do not significantly impact visibility at CIAs in other states." While it does not appear that this conclusion impacted the source selection process, it is not clear how Utah used this conclusion or whether it influenced their control technology determinations. NPS believes UDAQ's conclusion is

[194] See Appendix D for all FLM RH SIP review documents
[195] See Appendix D.1 and D.2 to view the full NPS review of Utah's RH SIP and supporting cost analyses

not compatible with their findings regarding the impact of Utah sources in Class I areas of neighboring states, and NPS recommends that UDAQ revise this section of the draft SIP by using a 1% threshold for determining significant impacts.

UDAQ Response: Section 6.A.2 has been revised in response to this comment.

5. Utah requested more information regarding where Utah stands in terms of RAVI for Class I areas. RAVI is a separate process from periodic SIP revisions. This avenue is rarely used by the FLMs to address specific sources causing visibility impairment at Class I areas. The NPS will not likely pursue RAVI certification unless the approaches identified in the periodic SIP revisions do not adequately address documented impairment.

6. UDAQ asked for feedback on using prescribed fire data from USFS to adjust projections. NPS does not take a position on the adjustment of glidepath end points for prescribed fire. We support UDAQ's determination to not use glidepath adjustments for estimated contributions from international emissions.

7. In Table 27: Sources initially selected to perform a Four-Factor analysis in draft SIP, section 7.A.1, NPS recommends identifying the nearest Class I area referenced in the "distance to nearest Class I area" column.

   UDAQ Response: A column identifying the nearest CIA has been added to Table 27 in section 7.A.1.

8. In section 8.D.6 there appears to be a typographical error listing Intermountain Generation Station closing in 2017.

   UDAQ Response: The typographical error in section 8.D.6 has been fixed and the closing year for IGS now reads as 2027.

9. NPS recommends UDAQ revise the permit limits for the Paradox Resources Lisbon Natural Gas Processing Plant to reflect the assumptions used to exclude this facility from four-factor analysis. NPS also recommends including the plant's recent actual emissions data in the SIP.

   UDAQ Response: UDAQ has received 2021 inventory data for the Lisbon Plant and created an emissions summary with resulting Q/d values in section 7.A.2.

10. NPS recommends that UDAQ conducts or requires a four-factor analysis for the Intermountain Power Intermountain Generation Station exploring opportunities to

improve the efficiency of the existing SO_2 scrubbers considering NO_x emissions for the remaining useful life of the facility.

UDAQ Response: UDAQ has been in contact with IGS concerning this matter. UDAQ believes the station's existing SO_2 scrubbers are sufficient and that the plant is well controlled. UDAQ has also included IGS's 2028 closure in the proposed part H language for this SIP located in Appendix A, which would make the closure federally enforceable.

11. NPS requests that UDAQ provide a breakdown of emissions from the Kennecott units the state can regulate versus those it cannot regulate. UDAQ should explain how its $PM_{2.5}$ SIP includes in-use requirements for this equipment.

    UDAQ Response: Section 7.A.2 was revised and a breakdown of Kennecott's emissions was included in response to this comment.

12. NPS recommends that UDAQ reduce haze causing SO_2 emissions from Hunter and Huntington facilities by requiring an evaluation of SO_2 scrubber optimization and potential efficiency improvements and implement any technically feasible and cost-effective options identified.

    UDAQ Response: PacifiCorp has provided additional information concerning their existing SO_2 scrubbing[196]. The existing FGD SO_2 controls at the Hunter and Huntington power plants all have control efficiencies of at least 90% and each unit at these plants are subject to an SO_2 emissions limit of 0.12 lb/mmBtu through their respective Title V permits. It is PacifiCorp's stance that these controls are running as efficiently as possible and there are no cost-efficient upgrades available. The "RPELs" proposed in PacifiCorp's original four-factor analysis "combined operational adjustments (such as reduced until utilization) with incremental capital and O&M costs". Additionally, PacifiCorp cited EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" ("2019 Guidance") which recognizes that it "may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement."[197] UDAQ is adding the existing SO_2 emission limits for all five units to SIP Section IX.H23, Source Specific Emission Limitations: Regional Haze Requirements, Reasonable Progress Controls, to ensure federal enforceability of PacifiCorp's SO_2 limits in the regional haze context. Section 7.C.3 has been revised to include this information and additional discussion in response to this NPS comment.

[196] Please refer to Appendix D.2.C to view PacifiCorp's document on Regional Haze Second Planning Period Issues Regarding SO_2 Controls for PacifiCorp's Power Plants
[197] See page 22 of https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf?VersionId=QC2nPZHuAH1VYmm3EuhV9ABIGm5rQynb.

13. NPS generally agrees with UDAQ's revisions to PacifiCorp's NO_x control technology cost analyses and used similar adjustments in their cost assessments. NPS also agrees with UDAQ that PacifiCorp's demonstration that the interest rate of 7.303% is their site-specific value and appropriate for use in their four-factor analyses.

14. NPS shares UDAQ's concerns with PacifiCorp's RPEL recommendation and support UDAQ's rejection of this proposal. RPEL would essentially be a "paper" reduction in emissions that would not reduce haze-causing emissions affecting visibility in Utah's CIAs.

15. NPS suggest that UDAQ could consider environmental co-benefits of NO_x emission reduction as part of this factor. NO_x is an ozone pre-cursor emission and ozone is known to affect both human and ecosystem health.

    UDAQ Response: UDAQ recognizes the co-benefits associated with pollutant emissions reductions and may highlight these benefits in the final draft of this SIP. However, UDAQ also recognizes the four-factor analysis[198] being the primary decision-making tool in this second implementation period and other benefits do not necessarily impact UDAQ's reasonable progress determinations.

16. NPS believes the cost of controls for the Sunnyside Cogeneration Facility are more economical than the company's estimates based on their calculations derived from the EPA Control Cost Manual. NPS disagrees with Sunnyside's use of a 7% interest rate and recommends UDAQ consider their control costs using the bank prime interest rate of 3.25%.

    UDAQ Response: Sunnyside Cogeneration provided additional justification found in Appendix D.2.A for the 7% interest rate they used in their control cost analysis. This rate was supported by a variety of institutions and most closely matched the financial indicators known by Sunnyside. UDAQ agrees with the final iterations of Sunnyside's estimated control costs.

17. NPS does not believe that Sunnyside has provided sufficient justification to exclude dry sorbent injection technology as technically feasible.

    UDAQ Response: UDAQ has received additional information regarding the feasibility and cost-effectiveness of dry sorbent injection technology from Sunnyside which has been included in Appendix D.2.G.

[198] Please refer to section 7.B to view the four factors used to determine control feasibility in this implementation period.

18. NPS's review of the Ash Grove Leamington Cement Plant suggests potential improvements may be available for their existing SNCR system. NPS recommends UDAQ request further evaluation of this opportunity to reduce NO_x emissions from the facility.

    UDAQ's Response: In response to UDAQ's four-factor analysis evaluation, Ash Grove provided additional information on the efficiency of their SNCR system[199]. Based on this information, UDAQ believes this facility is well controlled for the purposes of this implementation period.

19. NPS's review of the Graymont Cricket Mountain Plant finds that their permitted emissions levels are significantly higher than their recent emissions levels. NPS believes the costs of controls would be more cost effective if emissions increased to permitted levels. NPS recommends UDAQ consider tightening permitted emissions limits for NO_x and SO_2 to reflect future potential emissions and prevent backsliding.

    UDAQ Response: UDAQ contacted Graymont concerning their permitted emissions levels. The Cricket Mountain facility has seen a decrease in production over the past few years with special emphasis on the impacts of the COVID-19 pandemic. Graymont views this as a temporary decrease as the market is currently in the midst of recovery while they anticipate growth in their market. As this decrease is temporary, Graymont does not foresee the need to reduce its limits at this facility as it could reduce their flexibility to meet the market recovery and growth.

20. NPS recommends that numerical NO_x and SO_2 emissions limits be incorporated into US Magnesium's current permit for the turbines/duct burners, chlorine reduction burner, melt/reactor, riley boiler, and the diesel engines would ensure that reasonable progress assumptions and determinations for the facility are adhered to.

    UDAQ Response: UDAQ issued an order to US Magnesium to obtain the information required to respond to these comments. USM provided responses on April 26th and May 11th, 2022 which can be found in Appendix D.2.E and F.

21. NPS recommends UDAQ re-evaluate the feasibility and costs of US Magnesium installing SCR on their turbines.

    UDAQ Response: See response to comment 20.

22. NPS recommends UDAQ reconsider requiring implementation of SCR on US Magnesium's riley boiler as part of this implementation period. Additionally, actual emission assumptions relied on to eliminate SCR from consideration be reflected in permit limitations for this unit.

[199] Located in section 7.C.1 in Ash Grove's Evaluation Response

UDAQ Response: See response to comment 20.

23. NPS requests additional information and emissions verification on US Magnesium's diesel engines and engine replacement and/or electrification be included as additional emission control options in their four-factor analysis.

    UDAQ Response: See response to comment 20.

24. NPS recognizes the jurisdictional complexity of the Uintah and Paradox basins with 80% of the land being under tribal and EPA control. However, NPS recommends that air quality improvement will require cooperative and commensurate efforts from all agencies involved in air quality management in the basin and suggests UDAQ implement statewide rules to address oil and gas emission sources throughout Utah.

    UDAQ Response: Over the past several years, UDAQ has proposed and adopted a series of statewide rules specific to oil and gas operations found in Utah's state administrative rules R307-500 to 511. Though these rules have been focused on controlling VOC emissions, there is also a state-specific rule for natural gas-powered engines associated with oil and gas production. Since the rule was put in place in 2018, several sources have provided engine stack test data that have led UDAQ, EPA, and the Tribes to initiate further research and compliance studies on engines in the Basin, with a focus on two-stroke smaller horsepower engines that power pump jacks associated with oil-producing wells. The data collected have indicated lower values for NO_x emissions than what was reported in the 2017 oil and gas emission inventory for these engines, yet much higher emissions of VOCs. UDAQ will be evaluating this data and will be evaluating future rulemaking for engines associated with oil and gas operations that would be statewide. UDAQ will coordinate with EPA and the Tribe to encourage that rules are consistent across all regulatory jurisdictions, but ultimately any controls under EPA jurisdiction on sources in Indian Country will be determined by EPA and the Tribe.

    The main pollutant of concern in the Uinta Basin is ozone, with VOCs and NO_x being the actual precursor emissions that create ozone. Photochemical modeling has been a challenge in this area due to the complexity of the chemical reactions and unique geography and wintertime conditions. Therefore, it has not yet been determined what emission reductions will be the most effective to lower ozone values. However, initial thoughts are that the area is NO_x limited. If this is shown to be the case, then NO_x reductions will have a greater impact and as about 80% of NO_x emissions in the Basin are associated with engines, UDAQ will definitely evaluate the reduction in NO_x limits. As part of this evaluation, UDAQ will also keep in mind the NPS comments regarding the potential positive impacts on regional haze management. In summary, the evaluation of potentially lower VOC and NO_x limits for engines associated with oil and gas production is actively in progress and Utah is working on further controlling NO_x from engines for separate health standards.

9.C.3 USFS Feedback Summary and UDAQ Responses[200]

The USFS recognizes the emission reductions made in Utah over the past decade that have resulted in improvements in visibility at the Forest Service Class I Wilderness Areas and appreciates the working relationship among our respective staff. Overall, the USDA Forest Service found that the draft RH SIP is well organized and comprehensive. The Long-Term Strategies for this planning period appear to indicate that Forest Service Class I Wilderness Areas will continue to show visibility improvements better than the Uniform Rate of Progress (URP) through 2028, and USFS appreciates the commitment by UDEQ to evaluate progress in meeting the visibility goals during the 5-year progress reports.

40 CFR 51.308(f)(1)(vi)(B) allows states to adjust the glidepath to account for prescribed fire. The draft SIP states that no glidepath adjustment was made to account for prescribed fire emissions. The USFS encourages Utah DEQ to use the adjustment of glidepaths for the increased prescribed fire projections reflected in the “Future Fire Scenario 2” available in Product 18 of Modeling Express Tools of the WRAP TSS.

When considering the R_x fire end-point adjustment, the USFS is concerned that industry or other groups could improperly argue that additional controls are not necessary to make further progress if modeling demonstrates that the Class I Area in Utah is below adjusted glidepaths, essentially arguing that the glidepath provides safe harbor from additional control requirements. The USFS believes this “safe harbor” argument is erroneous and is not supported by the Regional Haze Rule.

UDAQ Response: UDAQ appreciates the feedback from USFS as well as their work on the wildland prescribed fire adjustment. UDAQ acknowledges the visibility impacts expected future increases in wildland prescribed fire may have on Utah as well as the importance of prescribed fire for conservation. However, the impact of USFS’s glidepath adjustment is less significant for Utah’s CIAs than for those in other states. While the international and wildland prescribed fire adjustments are available for Utah’s CIA glidepaths, UDAQ is choosing to remain conservative for the purposes of this implementation period by not using them. However, this choice does not preclude the use of glidepath adjustments in future planning periods, since international and wildland prescribed fire emissions do impact Utah CIAs and are largely beyond the control of individual states and since prescribed fires are seen to be an increasingly important tool for land managers in the future.

[200] See Appendix D.3 to view the full USFS RH SIP review document

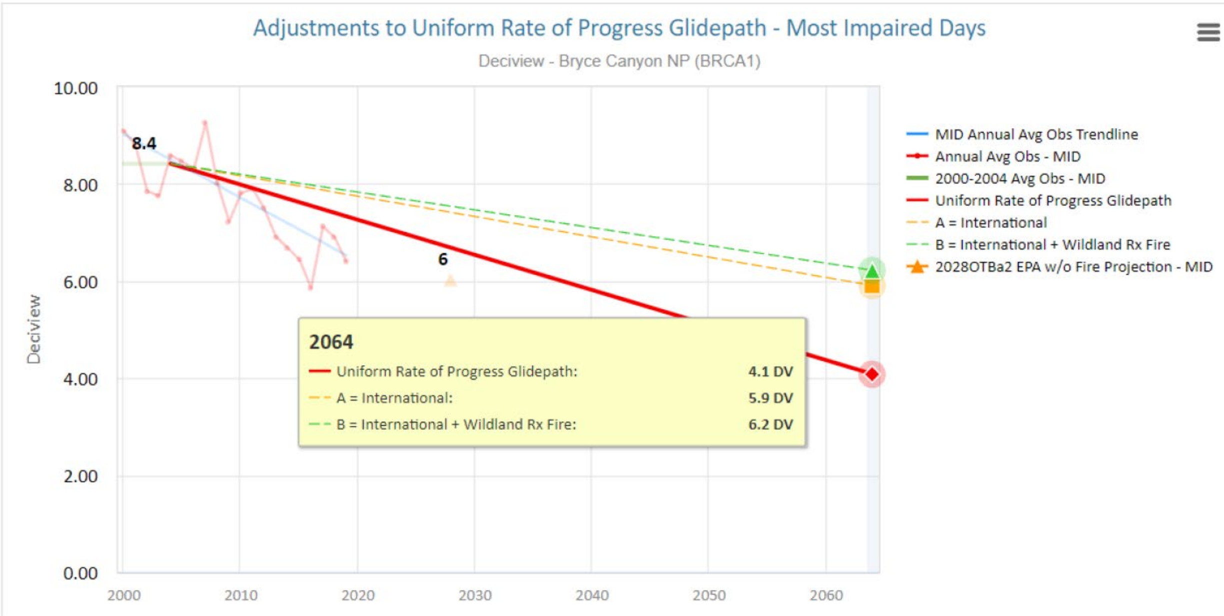

Figure 69: USFS Fire Glidepath Adjustment for Bryce Canyon

9.D Coordination with Indian tribes

Utah has five major tribes: the Ute, Dine' (Navajo), Paiute, Goshute, and Shoshone. There is one source in Northeast Utah where the Bonanza Power Plant is situated, but it resides in EPA jurisdiction. UDAQ sent the regional haze SIP draft to the tribes in Utah on December 9th, 2021, concurrently with submission to EPA and FLMs for a 60-day review. UDAQ has received no feedback from the tribes as of the submittal of this SIP. Documentation of this outreach can be found in Appendix E.

9.E Stakeholder Outreach and Communication

In the process of developing this SIP, Utah has been in contact with the five major sources subject to a four-factor analysis for controls feasibility. Upon evaluation of the five source's original four-factor analysis submittals, Utah evaluated and requested responses from each of the sources. This correspondence is summarized in Chapter 7. Utah has had several meetings with PacifiCorp concerning the implementation of controls in its Hunter and Huntington facilities. Utah also holds regular industry stakeholder meetings and environmental advocate meetings to update these groups on Utah's regional haze planning progress and address any questions or concerns they have regarding regional haze. Throughout the second implementation period, Utah also met with other state departments for coordination including the Department of Public Utilities and the Office of Energy Development.

Table 70: Summary of Stakeholder Meetings with UDAQ

Date	Time	Entity	Topic	Result

4/27/21	4-5p	PacifiCorp and Wyoming	Regional Haze Pre-Meeting	Discussed possible controls and power plant planning.
5/19/21	2-3p	Air Quality Advocates	DAQ-Utah Advocates Regional Haze Catch Up	Introduction to members of HEAL Utah, Sierra Club, and NPCA. They expect requirements for additional controls at power plants, especially Hunter and Huntington.
6/23/21	12-1:05p	PacifiCorp	Presentation on legal risks and 4-factor evaluation	Discussed possible controls and issues with 4-factor analysis.
7/7/21	10:30a-12p	RH Advocates Meeting	RH Update	Gave RH updates and discussed guidance vs rule issue.
7/15/21	3:30-4:30p	DAQ, OED, DPU	RH and Power Plant Planning	Gave RH overview/update, informed them of PacifiCorp 4-factor eval, control options, and rule vs. guidance.
7/19/21	9a	PacifiCorp	RH primer scheduling	Kirsten Merrit called about times for RH backgrounder.
7/20/21	9:15a	PacifiCorp	RH primer scheduling	Kirsten Merrit called about invitees for RH backgrounder.
10/27/21	8-9a	PacifiCorp	RH Follow-Up/Update	We discussed implementing new PALs for Hunter based on the emissions reductions installing SCR on Hunter 3 would have and Huntington based on their recent actuals in the 2028OTB modeling.
11/3/21	10:30-11:30a	Air Quality Advocates	RH Update	Gave presentation with RH overview, Utah's RH history, current planning, and updated timeline for Utah's round two SIP.
11/10/21	11a-12p	NPCA, Western Resources, & Sierra Club	RH Presentation Follow-Up	UDAQ addressed additional question resulting from the presentation given at the Air Quality Advocates Meeting.
12/3/21	11a-12p	PacifiCorp	RH Update	Discussed control options for Hunter and Huntington.
1/5/22	10:30-11:30a	Air Quality Advocates	RH Update	Offered to send the draft UT RH SIP to those who requested it via email.
1/26/22	11:49a	Sunnyside	Information Submittal	Sunnyside provided control cost spreadsheets via email by NPS request
3/2/22	10-11:30a	Air Quality Advocates	RH Update	Offered to send the FLM comment documents to those who requested it via email.
3/4/22	10-10:15a	PacifiCorp – Kirsten Merrit	RH Information	Offered technical responses to FLM comments concerning the Hunter and Huntington power plants
3/14/22	2-3p	Paradox Resources	RH Planning	Met with Paradox Resources to discuss FLM comments regarding their source, updating their permit for the Lisbon Plant, and obtaining 2021 inventory data.
3/17/22	3-4p	PacifiCorp	RH Planning	Discussed PacifiCorp's SO2 scrubbing equipment and efficiency as well as the possibility of optimization.
3/14/22	2-3p	Paradox	Information Request	Discussed emissions inventory data.
3/14/22	1:12p	Sunnyside	Interest Rates	Sunnyside provided interest rate justification via email.
3/17/22	4:12p	PacifiCorp	SO2 Scrubbing	PacifiCorp provided additional justification for SO2 scrubbing
3/21/22	1-2p	Sunnyside	Information Request	Discussed DSI feasibility.
4/18/22	1-2p	PacifiCorp	RH Discussion	Discussed future utilization.
4/20/22	4:42p	PacifiCorp	EPA Comments	UDAQ provided EPA public comments.
5/4/22	10-11:30a	Air Quality Advocates	RH Update	UDAQ provided the advocates with a RH update.
5/24/22	1:30-2:30p	Sunnyside	NPS Comment Questions	Sunnyside requested clarification on NPS comments.
5/24/22	2p	PacifiCorp	Public Hearing	Discussed public hearing logistics.
5/27/22	11:58a	Sunnyside	Public Comment Submittal	Sunnyside submitted public comments.
5/31/22	4:25p	PacifiCorp	Public Comment Submittal	PacifiCorp provided public comments on the RH SIP.

6/10/22	1-2p	PacifiCorp	RH Information	Discussed SO2 scrubbing.
6/22/22	10-11a	Sunnyside	Water Rights/CDS	Discussed water rights and CDS feasibility. Sunnyside provided additional documentation via email.
6/22/22	10:05a	PacifiCorp	Air Preheaters	PacifiCorp provided information on air preheater costs.

9.F Public Comment Period

Utah's RH SIP for the second implementation period was presented to the Air Quality Board at their April 6th, 2022 meeting. The Board approved a 30-day public comment period beginning on May 1st, 2022 and ending on May 31st, 2022. Notices regarding the public comment period and availability of the SIP draft were published in the State Bulletin, posted on the UDAQ webpage, published in the Salt Lake Tribune (04/26/2022), Deseret News (04/27/2022) and the Spectrum (05/01/2022), and the AQ board actions update. UDAQ held a public hearing on May 26th, 2022 for the submission of verbal comments. UDAQ's public notice was published on UDAQ's webpage from April 30th to June 2nd, 2022. Documentation of this notice can be found in Appendix F.

9.G Comment Conclusions

During the public comment period, UDAQ received written and verbal comments from the following:

- EPA
- NPS
- The Conservation Organizations[201]
- Utah Petroleum Association
- Utah Mining Association
- PacifiCorp
- US Magnesium
- Sunnyside Cogeneration
- Intermountain Power Service Corporation
- Utah Associated Municipal Power Systems
- City of Moab
- Grand County Commission
- 657 individuals

[201] Comments submitted jointly by the National Parks Conservation Association, Sierra Club, Utah Physicians for a Healthy Environment, The Coalition to Protect America's National Parks, the Healthy Environmental Alliance of Utah, and O2 Utah

UDAQ reviewed all comments[202] which are summarized by topic and responded to in Appendix H. Some comments resulted in SIP revisions which include:

- Updated inventory graphs in Section 3.A.4 upon request from the Air Quality Board.
- Section 6.A.10 was updated with a table detailing emission reduction quantification for the long-term strategy. Strategies were not changed; the table was added for clarification.
- A new table in Section 7.A.2 to show existing controls in Utah's SIP for screened sources that have resulted from other SIP revisions, including $PM_{2.5}$.
- Part of section 7.A.3 was struck out and rewritten for clarity and improved justification for emission limits at Hunter and Huntington power plants.
- An environmental justice analysis and writeup was added to section 7.A.5.
- Additions to appendices to include additional information that sources have submitted.
- Multiple minor additions or deletions due to oversights, or for clarifications.
- SIP Subsection IX.H.23 changes include:
  - emission limits for screened-in sources' existing limits that were not already in IX.H,
  - annual stack testing at US Magnesium,
  - SO_2 limit exemptions were removed for startup, shutdown, and malfunction for Huntington, and
  - minor adjustments to Hunter and Huntington limits based on the improved justification.

9.H Commitment to Further Planning

Utah will continue its regional haze planning efforts through consultation efforts, participation in regional haze work groups, and SIP development.

9.H.1 Process for conducting future emissions inventories and future monitoring strategy

Utah will continue to triennially update its statewide emissions inventory as dictated by the Air Emissions Reporting Requirements (AERR)[203] and Utah's Continuous Emissions Monitoring Program[204] to track regional haze progress, participate in regional haze modeling efforts, and track emissions trends.

[202] All public comments received by UDAQ on this SIP revision can be found on UDAQ's Current Regional Haze Planning web page here: https://deq.utah.gov/air-quality/regional-haze-in-utah#planning

[203] 73 Fed. Reg. 76539, 76552 (Dec. 17 2008). The AERR rule can be found at https://www.epa.gov/air-emissions-inventories/air-emissions-reporting-requirements-aerr

[204] Utah Admin. Code r. R307-170.

9.H.2 Commitment to provide other elements necessary to report on visibility, including reporting, recordkeeping, and other measures

Utah will provide any additional reporting, recordkeeping, and other measures necessary to continue its regional haze progress deemed necessary by the EPA or the regional haze work groups Utah participates in. At this time, no such additional efforts have been identified.

9.H.3 Commitment to submit January 31, 2025 progress report

Under the RHR, states must submit periodic progress reports to EPA evaluating their progress towards their RPGs. The 2017 RHR amendments adjusted the next progress report due date to be submitted by January 31, 2025. Utah commits to submitting this progress report and confirms that it will contain the following elements pursuant to the RHR:[205]

- Status of implementation of SIP measures for RPGs in Utah's CIAs and those outside the State identified as being impacted by emissions from within the state.
- Summary of emissions reductions in Utah adopted or identified as part of the RPG strategy.
- A five-year annual average assessment of the most and least impaired days for each CIA in Utah including the current visibility conditions, difference between current conditions and baseline, and change in visibility impairment over the five-year period.

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[205] See page 6 of https://gardner.utah.edu/wp-content/uploads/ERG2022-Full.pdf?x71849.