State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-033-22

UTAH AIR QUALITY BOARD MEETING
FINAL AGENDA

Wednesday, April 6, 2022 - 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116

Board members may be participating electronically. Interested persons can participate telephonically by dialing 1 669-238-0145 using access code: 370-578-582#, or via the Internet at meeting link: https://meet.google.com/tgb-ffhq-rvg

I. Call-to-Order

II. Date of the Next Air Quality Board Meeting: May 4, 2022

III. Approval of the Minutes for the February 2, 2022, Board Meeting.

IV. Propose for Public Comment: Amend R307-506. Oil and Gas Industry: Storage Vessel; R307-508. Oil and Gas Industry: VOC Control Devices; R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements; and R307-511. Oil and Gas Industry: Associated Gas Flaring. Presented by Sheila Vance.

V. Propose for Public Comment: Utah State Implementation Plan. Section XX.A: Regional Haze Second Implementation Period; Utah State Implementation Plan. Emission Limits and Operating Practices: Section IX, Part H.21 and Part H.23: R307-110-17. Section IX, Control Measures for Area and point Sources, Part H, Emission Limits; and R307-110-28. Regional Haze. Presented by Chelsea Cancino.

VI. Informational Items.
   A. Air Toxics. Presented by Leonard Wright.
   B. Compliance. Presented by Harold Burge and Rik Ombach.
   C. Monitoring. Presented by Braden Cluster.
   D. Other Items to be Brought Before the Board.
   E. Board Meeting Follow-up Items.

In compliance with the Americans with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Larene Wyss, Office of Human Resources at (801) 536-4281, TDD (801) 536-4284 or by email at lwyss@utah.gov.

ITEM 3

State of Utah

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UTAH AIR QUALITY BOARD MEETING
February 2, 2022 – 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116
DRAFT MINUTES

I. Call-to-Order

Randal Martin called the meeting to order at 1:30 p.m.

Board members present: Randal Martin, Erin Mendenhall, Michelle Bujdoso (attended electronically), Kevin Cromar (attended electronically), Cassady Kristensen (attended electronically), John Rasband (attended electronically), Arnold Reitze (attended electronically), Kimberly Shelley (attended electronically)

Executive Secretary: Bryce Bird

II. Date of the Next Air Quality Board Meeting: March 2, 2022

III. Approval of the Minutes for December 1, 2021, Board Meeting.

- Arnold Reitze motioned to approve the December 1, 2021, minutes. Erin Mendenhall seconded. The Board approved unanimously.

IV. Propose for Final Adoption: Repeal of R307-301. Utah and Weber Counties: Oxygenated Gasoline Program as a Contingency Measure. Presented by Bo Wood.

Bo Wood, Rules Coordinator at DAQ, stated that R307-301 established a contingency measure in the carbon monoxide state implementation plan. If triggered, it would have required gasoline sold in Utah and Weber counties during the winter months to be oxygenated with ethanol to a blend with 2.7%. In December 2021, division staff proposed the repeal of R307-301 and the Board approved a 30-day public comment period. The public comment period was held from December 15, 2021, to January 15, 2022. No comments were received and no public hearing was requested. Staff recommends that the Board approve the repeal of R307-301.

Ms. Mendenhall asked if the current 10% oxygenation blend is regulated, or is that simply a cap of the formula that the industry has taken. Staff responded that the current 10% ethanol in fuel is a Congressional mandate.

- Erin Mendenhall motioned that the Board approved the repeal of R307-301. Michelle Bujdoso seconded. The Board approved unanimously.

V. Informational Items.

A. Linkages between Air Quality and the Shrinking Great Salt Lake. Presented by Dr. Kevin Perry, University of Utah.

Dr. Kevin Perry, Associate Professor at the University of Utah, made a presentation about the linkages between the air quality and the shrinking Great Salt Lake (GSL), focusing mainly on potential air quality issues. Dr. Perry's presentation covered three items of potential air quality impacts which included: exposed playa is a known source of PM_{10} and $PM_{2.5}$, exposed playa is also a potential source of hazardous air pollutants (HAPs), and exposed playa is hypothesized to increase ozone production due to increased actinic flux.

Part of the presentation described results from the GSL study which was conducted from 2016 to 2018 and jointly funded by the Utah Division of Natural Resources and the Utah Division of Facilities, Construction, and Management as part of the construction for the new prison. For the first impact regarding PM_{10} and $PM_{2.5}$, Dr. Perry described the field work used to identify GSL dust source regions such as hot spots in several quadrants. It is important to protect the fragile surface crust on the GSL lake bed because once you destroy that crust then you have a much larger area of the surface that can act as a dust source. Another goal of the study was to estimate how fluctuating lake levels might impact future dust production from the GSL. And finally, to determine if PM_{10} dust from the GSL contains heavy metals which might pose a threat to human health.

Exposed playa can be a potential source of HAPs. Dr. Perry's focus was on heavy metal which was part of the GSL project where they did measurements to determine if the GSL sediment contained significant quantities of heavy metals. They used regional screening levels to determine potential risk for the adjacent populations. He noted that arsenic in essentially every measurement exceeded the regional screening levels for both residential and industrial exposures, but added that arsenic is fairly uniformly distributed over the entire lake bed. This indicates to Dr. Perry that it has a natural origin and that the rocks of Utah are just higher in arsenic and that the sediments that end up in the GSL are a result of that natural phenomenon. Other elements had potential concern as well. The GSL dust poses both acute and chronic health risks from the PM_{10}, the $PM_{2.5}$, and the heavy metals, and all residents of northern Utah are likely to be exposed from these various dust source regions on the GSL.

Dr. Perry concluded with a brief explanation of the hypothesis of how the exposed playa can also increase ozone production due to an increased actinic flux where ultraviolet radiation passes through the precursor gases of NO_x and VOCs to produce ozone in the atmosphere using the different underlying surfaces between a water covered lake and a playa covered lake. Finally, failure to address the future of the GSL could threaten the hard-earned air quality improvements from PM_{10}, $PM_{2.5}$, and ozone resulting in costly federally-mandated mitigation.

Mr. Martin asked about the size distribution to particle, what fraction of the $PM_{2.5}$ compared to PM_{10}? Dr. Perry responded that the PM_{10} to $PM_{2.5}$ fraction is one of the unknowns. He attempted to look at the size distribution but because of the soluble nature of the evaporite minerals, as soon as you do a traditional particle size distribution in any kind of aqueous environment it changes the particle size distribution.

Mr. Martin asked if he prepared any data from the field or from the DAQ sites, when a dust event occurred? Dr. Perry responded that no, he has not done that systematically yet, but that is something they will be following up on.

When asked if GSL study has been published, Dr. Perry responded that all of the work is available in a final report that was submitted to the Utah Division of Natural Resources. The data itself has not been published yet and it is currently going through the peer review process.

Ms. Mendenhall asked if we should be looking into the possible impacts of these dust events on our local monitors, and therefore our residents? For example, with the presence of arsenic. Dr. Perry explained that part of the issue is that with the monitoring schedule, when there is a dust event, there is a 2/3 likelihood that we will miss it in terms of the chemical composition data. They have the data available going backwards in time. Also, it's not just the GSL, there are several other playa surfaces in the Intermountain West that contribute. Part of the problem is teasing out the contribution from the West Desert versus the GSL. All of these are potential dust sources that are typically mixed by the time they end up at the receptor site.

B. University of Utah Energy Assessments. Presented by Dr. Kerry Kelly, University of Utah.

Dr. Kerry Kelly, Associate Professor at the University of Utah, introduced that the StepWise Program has a goal to adopt cost-effective strategies that also have an air quality benefit. They are also focusing on area sources that are not on the radar screen of the DAQ. The program aligns with state priorities as part of the Utah Road Map by identifying energy efficiency strategies as a way to reduce air quality emissions and as a way to be cost-effective and promote competitiveness.

Moriah Henning, StepWise Program Engineer, explained that the team members of the program will go out and do assessments to identify high impact natural gas efficiency projects. They use a team of professionals to perform these evaluations while also providing opportunities for students in the program to get involved and develop their engineering skills. Through the program they serve manufacturers, municipalities, commercial building owners, and they are starting work with some school districts as well. The overall goal is to find and serve customers who may have prior natural gas usage but don't have the resources or in-house expertise to find energy projects themselves.

Alexis Jenson, employee of the StepWise Program and the Intermountain Industrial Assessment Center (IIAC), explained that the StepWise and the IIAC programs employ undergraduate PhD students where they receive real engineering experience, on-the-job training, and in-class instruction on steam, electricity, energy, management, etc. Ms. Jenson then gave a brief explanation of the assessment process which included the prework, a plant visit, the analysis and reporting, and follow-up.

Dr. Kelly explained how they estimated the potential emission savings by developing a range of emission estimates for electricity and using AP-42 emission factors for natural gas. Since the start of the program in March 2021, they have complete 16 assessments in the modeled nonattainment regions. The energy savings for all 16 assessments identified potential savings of $2.9 million in utility bill savings. On average the savings identified will reduce about 15% of each facilities natural gas usage. And 80 projects identified in the 16 assessments have an average 6-year simple payback period for each project.

Ms. Mendenhall commented that some of the capital costs associated with any of the suggested improvements can be prohibitive, and asks if there are any grants or low interest loan programs such as CPACE that could help with those costs? Ms. Henning replied that the program is hoping to expand in the future and to use additional funding through Dominion and Step legislation to provide financial assistance to customers.

Mr. Martin asked what mechanism did the program propose to get the big NO_x reduction from all of clients? Ms. Henning responded that she is not sure specifically what contributed to the NO_x reductions but that the reductions came from a variety of processes that were assessed over the various client projects.

Mr. Martin asked if they have a sense from the potential clients and customers about their buy-in to go to these different strategies? Ms. Henning answered that historically the IIAC programs have a 50% implementation rate. Since the StepWise program is in its first year they do not have the numbers yet for the specific assessments at this time.

C. Air Toxics. Presented by Leonard Wright.

D. Compliance. Presented by Harold Burge and Rik Ombach.

E. Monitoring. Presented by Bo Call.

Bo Call, Air Monitoring Section Manager at DAQ, gave a brief update on the monitoring charts and noted that the preliminary data show that we are not meeting the ozone standard in most places that are monitored in 2021.

Ms. Bujdoso asked if Mr. Call could explain again the potential impacts of going back into nonattainment. Mr. Call listed some preliminary ozone numbers at various monitoring sites and stated that he is not sure how those will impact current activities with regard to what course EPA may take. For particulate, even though the past year had a lot of higher numbers throughout the network, our 3-year running average on the 98th percentile number pretty much shows us in attainment in most every place. Mr. Call then explained how staff analyzes data sets at the multiple samplers to determine which data set is going to be the primary data set and which is going to be the co-located data. There is also some concern about the annual standard which is at about 12. Our highest location right now is 11 on an annual number and the lowest is down in the 6's. This becomes important because EPA is considering lowering that standard.

Ms. Bujdoso asked if DAQ has three years of data for the near-road monitor? Mr. Call responded that DAQ does. This three year average is not completed because an additional monitor was added during the year and a few more filters still need to be added into the system.

Ms. Bujduso asked if Mr. Call knew what is contributing to high ozone in the areas without a lot of population or mobile sources? Mr. Call explained that the guidance that the DAQ goes by is that ozone monitors are to be sited downwind of the sources by a fair distance. This is so that any pollution that is emitted has time to get up into the atmosphere and be acted upon photochemically by the sun and cause ozone formation. So it's not uncommon to see the high ozone in remote places because they could be miles downwind of some source. Along the Wasatch Front where we have the most monitors the prevailing winds can push the ozone cloud to different places. In addition, some studies have shown there can be ozone transport coming from other places. And also, in the mountainous West we generally tend to have a much higher background than a lot of other places around the country.

F. Other Items to be Brought Before the Board.

Mr. Bird announced that Governor Cox recommended Commissioner Greg Todd from Duchesne County to fill the vacancy on the Board. After a 30-day public comment period, Commissioner Todd's recommendation has been forwarded to the State Senate for final approval.

G. Board Meeting Follow-up Items.

Meeting adjourned at 2:37 p.m.

ITEM 4

State of Utah

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DIVISION OF AIR QUALITY
Bryce C. Bird
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DAQ-029-22

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Director

FROM: Sheila Vance, Environmental Scientist

DATE: March 22, 2022

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend R307-506. Oil and Gas Industry: Storage Vessel; R307-508. Oil and Gas Industry: VOC Control Devices; R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements; and R307-511. Oil and Gas Industry: Associated Gas Flaring.

In January 2018, the Air Quality Board promulgated new rules for oil and gas well sites that established a streamlined process for minor oil and gas source permitting by replacing the source-by-source permitting process with what is referred to as permit-by-rule (PBR). The PBR system benefits producers, UDAQ, and the public because it reduces permitting costs, eliminates several administrative steps in the permitting process, reduces permit engineering time, and ensures consistency of operational requirements.

Since the implementation of the PBR system, UDAQ has conducted several research projects and performed hundreds of site visits and inspections. This has led to new information that prompted the need to update several of the oil and gas rules. The impacted rules are associated with oil and gas storage vessels, VOC control devices, leak detection and repair (LDAR), and associated gas flaring.

The most impactful study conducted was the Uinta Basin Composition Study (UBCS) where separator gas discharge and pressurized liquids samples were collected and analyzed to estimate flash gas emissions from tanks. Samples were collected from 50 oil wells and 17 gas wells in the Uinta Basin from November 2018 to February 2019. This study provided a much more robust data set than what UDAQ previously relied on. The UBCS had a larger sample size, uniform sampling and analytical methods, one sampling facility and analyst, and the samples were collected in a narrow time window compared with the previous data set.

Storage Vessel Control Requirements

Per R307-506, a storage vessel is required to be controlled if it emits 4 tons per year (tpy) of VOCs. The current throughput value for oil storage vessels is 8,000 barrels over a 12-month rolling average, which was a conservative estimate based upon a national emission factor. With the UBCS data set, UDAQ recalculated estimated emissions from storage vessels and re-evaluated the product throughput that equates to the 4 tpy. The UDAQ determined a more area-specific emission factor that lowered the throughput value for oil storage vessels from 8,000 barrels to 3,200 barrels.

The reduction in throughput values for oil storage vessels is the most impactful change to the current Utah oil and gas rules as it will require owners and operators to potentially install new emission control equipment that will require more operational maintenance as well as semi-annual leak detection and repair inspections. The most current production data from 2021 indicates that lowering the throughput value may impact 160 oil well sites and reduce VOC emissions by approximately 1,100 tpy. The cost of retrofitting tanks and installing a combustor is approximately $4,470 per ton of VOC reduced.

Removing Exemption for Permitted Facilities

Prior to the PBR system, the majority of oil and gas sources in the Basin were not permitted. Some sources did have Air Orders (permits) and these facilities were exempted from the rules even though their emission were above 4 tpy. The exemptions included tank emission controls, LDAR, and flaring of associated gas. These proposed amendments remove the approval order exemption for approximately 94 facilities, and reduce annual VOC emissions by about 313 tpy. This change will promote equitable requirements and ease of compliance for oil and gas wells in the state.

Emergency Tanks

There are times that for safety reasons, a facility needs to utilize a tank for unexpected overfills or other unexpected downstream operational upsets. These “emergency tanks” are not always controlled, and can lead to significant VOC emissions in a short period of time when uncontrolled. R307-506 currently states that emergency tanks need to be emptied within 15 days and UDAQ is proposing to amend the timeframe to 48 hours. Since the tanks are used in an emergency situation it should be an operational priority to remove the material as quickly as possible.

Leak Detection and Repair

The 2017 oil and gas emission inventory attributes approximately 30% of VOC emissions to tank control failures and fugitive emissions. LDAR inspections aid in the discovery of large control failures and leaks. To encourage focused LDAR inspections prior to the January - March winter ozone season in the Uinta Basin, UDAQ is proposing to require one of the semiannual inspections to occur between September and December. This has some impact on the current inspection schedules; however, having four months to complete the one semiannual inspection should provide ample time to complete an already required inspection.

The other proposed LDAR amendment is to perform an inspection after a well has been temporarily shut in. When production is turned “off” at a well site the conditions change such that when the production is turned back on, well pressures and equipment status may have changed. It’s important to evaluate the well sites for potential leaks and fugitive emissions upon restart of the well. Since the well site is required to have semi-annual LDAR inspections while in operation, this would count as one of the required inspections.

Stakeholder Outreach and Comments

Other changes in the proposed rules are slight clarifications on definitions and conditions. The UDAQ staff provided advanced notice of the proposed changes to the oil and gas rules in December 17, 2021, to a variety of stakeholders. UDAQ received helpful comments and made changes to the draft proposed rules. One of the well operator concerns is the timing of compliance with the rules, which is January 1, 2023, for the storage vessel controls. Commenter's mentioned that supply chain issues and labor shortages may make this date hard, if not impossible to meet. The proposed date is important to reduce VOC emissions as a precursor pollutant to ozone in the winter months. The Uinta Basin nonattainment area has had three winters without exceeding the 2015 ozone standard, but there are still incidents of high ozone levels and continuing to maintain the standard is important. Creating consistency in rules and reasonable technological requirements to maintain the current ozone standard will allow future economic growth and good air quality for the Uinta Basin.

Recommendation: Staff recommends that the Board propose for public comment R307-506. Oil and Gas Industry: Storage Vessel; R307-508. Oil and Gas Industry: VOC Control Devices; R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements; and R307-511, Oil and Gas Industry: Associated Gas Flaring as amended.

State of Utah
Administrative Rule Analysis
Revised November 2021

NOTICE OF PROPOSED RULE		
TYPE OF RULE: New ___; Amendment _X__; Repeal ___; Repeal and Reenact ___		
	Title No. - Rule No. - Section No.	
Utah Admin. Code Ref (R no.):	**R307-506**	**Filing ID (Office Use Only)**
Changed to Admin. Code Ref. (R no.):	**R**	

Agency Information

1. Department:	Department of Environmental Quality	
Agency:	Division of Air Quality	
Room no.:		
Building:	MASOB	
Street address:	195 North 1950 West	
City, state and zip:	Salt Lake City, Utah 84116	
Mailing address:	P.O. Box 144820	
City, state and zip:	Salt Lake City, Utah 84114-4820	
Contact person(s):		
Name:	**Phone:**	**Email:**
Bo Wood	385-499-3416	rwood@utah.gov
Sheila Vance	801-518-3132	svance@utah.gov
Please address questions regarding information on this notice to the agency.		

General Information

2. Rule or section catchline:

R307-506. Oil and Gas Industry: Storage Vessel

3. Purpose of the new rule or reason for the change (Why is the agency submitting this filing?)**:**

These amendments are necessary to align current oil and gas rules with new data from studies and compliance inspections. These changes reflect more accurate emission calculations that indicate a previous underestimation of VOC emissions from tanks and other components. The proposed changes will ensure the protection of air quality standards and improve compliance with required emission controls.

4. Summary of the new rule or change (What does this filing do? If this is a repeal and reenact, explain the substantive differences between the repealed rule and the reenacted rule)**:**

This rule modifies the definition of “emergency storage relief vessel”, removes an applicability exemption previously granted to producing wells with an approval order issued under R307-401, modifies storage vessel requirements for emission controls and adds a requirement to submit site specific data to UDAQ when it is used.

Fiscal Information

5. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:

A) State budget:

The fiscal impact from these amendments on the state budget for FY22, FY23, and FY24 is estimated to be between a benefit of $9,400 and a cost of $21,620. There are 94 facilities that have an exemption through their approval order and it’s their choice to either keep the approval order or switch to permit-by-rule. Cancelling an existing approval order requires producers to enroll in the permit-by-rule system. The one-time fee to cancel an approval order ranges from $220 to $550. This could increase state revenue by between $20,680 and $51,700, but is offset by the elimination of the $150 approval order annual fee per facility - $14,400 total. The number of facilities that will choose to move to the permit-by-rule system is unknown, but the incentive structure makes switching cost effective in less than 4 years. The exact cost for each facility to switch is also unknown, but DAQ anticipates that the fiscal impact on the state budget will fall within the range outlined above.

B) Local governments:

This rule change is not expected to have any fiscal impact on local governments.

C) Small businesses ("small business" means a business employing 1-49 persons)**:**

This rule change may impact up to 8 small businesses that own and operate oil and gas wells in Utah. The one-time cost to implement the control measures required by this rule is approximately $106,000 per well. Emission inventory data indicate that as many as 160 wells may be impacted by this action. The proportion of these wells operated by small businesses is unknown, but believed to be small. The fiscal impact of this change is unknown because the number of operating wells and production levels varies greatly in response to global market fluctuation. Existing wells producing more than 8,000 barrels per year are currently required to implement these controls and will experience no fiscal impact from this change. Wells producing less than 3,200 barrels of crude oil or 2,000 barrels of condensate per year are exempt and will see no fiscal impact from this change.

D) Non-small businesses ("non-small business" means a business employing 50 or more persons)**:**

This rule change may impact up to 12 non-small businesses that own and operate oil and gas wells in Utah. Emission inventory data indicate that as many as 160 wells may be impacted by this action. The proportion of these wells operated by non-small businesses is unknown. The fiscal impact of this change is unknown because the number of operating wells and production levels varies greatly in response to global market fluctuation. Existing wells producing more than 8,000 barrels per year are currently required to implement these controls and will experience no fiscal impact from this change. Wells producing less than 3,200 barrels of crude oil or 2,000 barrels of condensate per year are exempt and will see no fiscal impact from this change.

E) Persons other than small businesses, non-small businesses, state, or local government entities ("person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an ***agency***)**:**

This rule change is not expected to have any fiscal impact on persons other than small businesses, non-small businesses, state, or local government entities.

F) Compliance costs for affected persons (How much will it cost an impacted entity to adhere to this rule or its changes?)**:**

The compliance costs for affected persons is expected to be approximately $106,000 per well.

G) Comments by the department head on the fiscal impact this rule may have on businesses (Include the name and title of the department head):

6. A) Regulatory Impact Summary Table (This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they will not be included in this table. Inestimable impacts will be included in narratives above.)

Regulatory Impact Table

Fiscal Cost	**FY2022**	**FY2023**	**FY2024**
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Cost	**$0**	**$0**	**$0**
Fiscal Benefits			
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Benefits	**$0**	**$0**	**$0**
Net Fiscal Benefits	**$0**	**$0**	**$0**

B) Department head approval of regulatory impact analysis:

The Executive Director of the Department of Environmental Quality, Kim Shelley, has reviewed and approved this fiscal analysis.

Citation Information

7. Provide citations to the statutory authority for the rule. If there is also a federal requirement for the rule, provide a citation to that requirement:

19-2-104		

Incorporations by Reference Information

(If this rule incorporates more than two items by reference, please include additional tables.)

8. A) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**	
	First Incorporation
Official Title of Materials Incorporated (from title page)	
Publisher	
Date Issued	
Issue, or version	

B) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**	
	Second Incorporation
Official Title of Materials Incorporated (from title page)	
Publisher	
Date Issued	
Issue, or version	

Public Notice Information

9. The public may submit written or oral comments to the agency identified in box 1. (The public may also request a hearing by submitting a written request to the agency. See Section 63G-3-302 and Rule R15-1 for more information.)		
A) Comments will be accepted until (mm/dd/yyyy)**:**		5/31/2022
B) A public hearing (optional) will be held:		
On (mm/dd/yyyy)**:**	**At** (hh:mm AM/PM)**:**	**At** (place)**:**
May 24, 2022	1:00PM	https://meet.google.com/ozt-syme-rum?hs=122&authuser=0

10. This rule change MAY become effective on (mm/dd/yyyy)**:**	07/07/2022
NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date. To make this rule effective, the agency must submit a Notice of Effective Date to the Office of Administrative Rules on or before the date designated in Box 10.	

Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 302, 303, and 402. Incomplete forms will be returned to the agency for completion, possibly delaying publication in the *Utah State Bulletin* and delaying the first possible effective date.			
Agency head or designee, and title:	Bryce C. Bird, Director	**Date** (mm/dd/yyyy)**:**	

R307. Environmental Quality, Air Quality.
R307-506. Oil and Gas Industry: Storage Vessel.
R307-506-1. Purpose.

R307-506 establishes requirements to control emissions of volatile organic compounds (VOCs) from storage vessels associated with a well site.

R307-506-2. Definitions.

"Centralized Tank Battery" means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site.

"Emergency Relief Storage Vessel" means a storage vessel receiving oil, condensate, or produced water as a result of emergency situations, process upsets, or other equipment malfunctions.

"Emergency Situations" means temporary, infrequent and unavoidable situation in which is uncontrollable or necessary to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment and is an unanticipated event or failure that is out of the operator's control and is not due to operator negligence.

"Modification to a well site" means;

(1) a new well is drilled at an existing well site,

(2) a well at an existing well site is hydraulically fractured, or

(3) a well at an existing well site is hydraulically refractured.

"Storage Vessel" means storage vessel as defined in 40 CFR 60.5430a, Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, which is incorporated by reference in R307-210.

"Uncontrolled emissions" means actual emissions or the potential to emit without consideration of controls.

R307-506-3. Applicability.

(1) R307-506 applies to each storage vessel located at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) R307-506 ~~shall apply to~~ applies to each storage vessel located at centralized tank batteries.

~~(3) R307-506 does not apply to storage vessels that are subject to an approval order issued under R307-401-8.~~

R307-506-4. Storage Vessel Requirements.

(1) Thief hatches on storage vessels shall be kept closed and latched except during vessel unloading or other maintenance activities.

(2) All storage vessels ~~located at a well site that are in operation as of January 1, 2018,~~ subject to R307-506 with a site-wide throughput of 8,000 barrels or greater of crude oil or 2,000 barrels or greater of condensate per year on a rolling 12-month basis shall comply with R307-506-4(2)(a) ~~unless the exemption in R307-506-4(2)(b) applies~~. Effective January 1, 2023, all storage vessels subject to R307-506 with a site-wide throughput of 3,200 barrels or greater of crude oil or 2,000 barrels or greater of condensate per year on a rolling 12-month basis shall comply with R307-506-4(2)(a).

(a) VOC emissions from storage vessels in service shall either be

routed to a process unit where the emissions are recycled, incorporated into a product and/or recovered, or be routed to a VOC control device that is in compliance with R307-508.

(b) All storage vessels located at a well site shall be exempt from R307-506-4(2)(a) if combined VOC emissions from the storage vessels are demonstrated to be less than four tons per year of uncontrolled emissions on a rolling 12-month basis.

(i) VOC working and breathing losses, and flash emissions from storage vessels shall be calculated using direct site-specific sampling data and any software program or calculation methodology in use by industry that is based on AP-42 Chapter 7.

(3) Upon startup of operation of a well site or centralized tank battery ~~All storage vessels that begin operations on or after January 1, 2018, are required to control~~ VOC emissions from all storage vessels shall be controlled in accordance with R307-506-4(2)(a) ~~upon startup of operation~~ for a minimum of one year.

(4) An emergency relief storage vessel located at a well site shall be exempt from R307-506-4(2)(a), if it meets the following requirements:

(i) The emergency relief storage vessel shall not be used as an active storage ~~tank~~ vessel.

(ii) The owner or operator shall empty the emergency storage relief vessel no later than ~~15 days~~ 48 hours after receiving fluids.

(iii) The emergency relief storage vessel shall be equipped with a liquid level gauge or equivalent device.

(5) An owner or operator that is required to control emissions in accordance with R307-506-4(2) and R307-506-4(3) shall inspect at least once a month each closed vent system, including vessel openings, thief hatches, pressure relief devices and bypass devices, for defects that can result in air emissions according to 40 CFR 60.5416a(c).

(a) If defects are discovered, the defects shall be corrected or repaired within 15 days of identification.

(6) Modification to a well site shall require a re-evaluation of site-wide throughput and/or emissions in accordance with R307-506-4(2).

(7) After a minimum of one year of startup of a well site or centralized tank battery, storage vessel controls may be removed if site-wide throughput is less than ~~8,000~~ 3,200 barrels of crude oil or 2,000 barrels of condensate on a rolling 12-month basis or uncontrolled actual emissions are demonstrated to be less than four tons per year.

R307-506-5. Recordkeeping and Reporting.

(1) Records of each closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass device shall be kept for three years.

(a) Records of each closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass device shall include the date of the inspection, the status of each closed vent system, including vessel openings, thief hatches, pressure relief devices and bypass device, and the date of corrective action taken if required.

(2) Records of crude oil throughput shall be kept for three years and shall be determined on a monthly basis using the production data reported to the Utah Division of Oil, Gas, and Mining.

(3) Records of emission calculations, actual emissions, and site-

specific sampling data used to determine compliance with R307-506-4(2)(b) shall be provided to the Utah Division of Air Quality prior to removal of control equipment and kept for a period of three years, post registration.

(4) Records of emergency relief storage vessel usage shall be kept for a period of three years.

(a) Records of emergency relief storage vessel usage shall include the date the vessel received fluids or was discovered to have received fluids, the date the overflow tank was emptied, and the volume of fluids emptied in barrels.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

State of Utah
Administrative Rule Analysis
Revised November 2021

NOTICE OF PROPOSED RULE		
TYPE OF RULE: New ___; Amendment _X__; Repeal ___; Repeal and Reenact ___		
	Title No. - Rule No. - Section No.	
Utah Admin. Code Ref (R no.):	**R307-508**	**Filing ID (Office Use Only)**
Changed to Admin. Code Ref. (R no.):	**R**	

Agency Information

1. Department:	Department of Environmental Quality	
Agency:	Division of Air Quality	
Room no.:		
Building:	MASOB	
Street address:	195 North 1950 West	
City, state and zip:	Salt Lake City, Utah 84116	
Mailing address:	P.O. Box 144820	
City, state and zip:	Salt Lake City, Utah 84114-4820	
Contact person(s):		
Name:	**Phone:**	**Email:**
Bo Wood	385-499-3416	rwood@utah.gov
Sheila Vance	801-518-3132	svance@utah.gov
Please address questions regarding information on this notice to the agency.		

General Information

2. Rule or section catchline:

R307-508. Oil and Gas Industry: Dehydrators

3. Purpose of the new rule or reason for the change (Why is the agency submitting this filing?)**:**

These amendments are necessary to align current oil and gas rules with new data from studies and compliance inspections. These changes reflect more accurate emission calculations that indicate a previous underestimation of VOC emissions from tanks and other components. The proposed changes will ensure the protection of air quality standards and improve compliance with required emission controls.

4. Summary of the new rule or change (What does this filing do? If this is a repeal and reenact, explain the substantive differences between the repealed rule and the reenacted rule)**:**

This rule removes an applicability exemption previously granted to producing wells with an approval order issued under R307-401.

Fiscal Information

5. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:

A) State budget:

The fiscal impact from these amendments on the state budget for FY22, FY23, and FY24 is estimated to be between a benefit of $9,400 and a cost of $21,620. There are 94 facilities that have an exemption through their approval order and it's their choice to either keep the approval order or switch to permit-by-rule. Cancelling an existing approval order requires producers to enroll in the permit-by-rule system. The one-time fee to cancel an approval order ranges from $220 to $550. This could increase state revenue by between $20,680 and $51,700, but is offset by the elimination of the $150 approval order annual fee per facility - $14,400 total. The number of facilities that will choose to move to the permit-by-rule system is unknown, but the incentive structure makes switching cost effective in less than 4 years. The exact cost for each facility to switch is also unknown, but DAQ anticipates that the fiscal impact on the state budget will fall within the range outlined above.

B) Local governments:

This rule change is not expected to have any fiscal impact on local governments.

C) Small businesses ("small business" means a business employing 1-49 persons)**:**

This rule change is not expected to have any fiscal impact on small businesses.

D) Non-small businesses ("non-small business" means a business employing 50 or more persons)**:**

This rule change is not expected to have any fiscal impact on non-small businesses.

E) Persons other than small businesses, non-small businesses, state, or local government entities ("person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an ***agency***)**:**

This rule change is not expected to have any fiscal impact on persons other than small businesses, non-small businesses, state, or local government entities.

F) Compliance costs for affected persons (How much will it cost an impacted entity to adhere to this rule or its changes?)**:**

This rule change will not have a compliance cost for affected persons.

G) Comments by the department head on the fiscal impact this rule may have on businesses (Include the name and title of the department head):

6. A) Regulatory Impact Summary Table (This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they will not be included in this table. Inestimable impacts will be included in narratives above.)

Regulatory Impact Table

Fiscal Cost	**FY2022**	**FY2023**	**FY2024**
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Cost	**$0**	**$0**	**$0**
Fiscal Benefits			
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Benefits	**$0**	**$0**	**$0**
Net Fiscal Benefits	**$0**	**$0**	**$0**

B) Department head approval of regulatory impact analysis:

The Executive Director of the Department of Environmental Quality, Kim Shelley, has reviewed and approved this fiscal analysis.

Citation Information

7. Provide citations to the statutory authority for the rule. If there is also a federal requirement for the rule, provide a citation to that requirement:

19-2-104		

Incorporations by Reference Information

(If this rule incorporates more than two items by reference, please include additional tables.)

8. A) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**

	First Incorporation
Official Title of Materials Incorporated (from title page)	
Publisher	
Date Issued	
Issue, or version	

B) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**

	Second Incorporation
Official Title of Materials Incorporated (from title page)	
Publisher	
Date Issued	
Issue, or version	

Public Notice Information

9. The public may submit written or oral comments to the agency identified in box 1. (The public may also request a hearing by submitting a written request to the agency. See Section 63G-3-302 and Rule R15-1 for more information.)		
A) Comments will be accepted until (mm/dd/yyyy)**:**		5/31/2022
B) A public hearing (optional) will be held:		
On (mm/dd/yyyy)**:**	**At** (hh:mm AM/PM)**:**	**At** (place)**:**
May 24, 2022	1:00PM	https://meet.google.com/ozt-syme-rum?hs=122&authuser=0

10. This rule change MAY become effective on (mm/dd/yyyy)**:**	07/07/2022
NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date. To make this rule effective, the agency must submit a Notice of Effective Date to the Office of Administrative Rules on or before the date designated in Box 10.	

Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 302, 303, and 402. Incomplete forms will be returned to the agency for completion, possibly delaying publication in the *Utah State Bulletin* and delaying the first possible effective date.			
Agency head or designee, and title:	Bryce C. Bird, Director	**Date** (mm/dd/yyyy)**:**	

R307. Environmental Quality, Air Quality.
R307-508. Oil and Gas Industry: VOC Control Devices.
R307-508-1. Purpose.

R307-508 establishes requirements for VOC control devices associated with well sites used to control emissions of VOCs.

R307-508-2. Applicability.

(1) R307-508 applies to each VOC control device located at a well site as defined in 40 CFR 60.5430a Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) R307-508 shall apply to centralized tank batteries, as defined in R307-506-2.

~~(3) R307-508 does not apply to VOC control devices that are subject to an approval order issued under R307-401-8.~~

R307-508-3. VOC Control Device Requirements.

(1) A VOC control device required by R307-506 or R307-507 must have a control efficiency of 95% or greater.

(a) The VOC control device shall operate with no visible emissions.

(b) The VOC control device must comply with R307-503.

(2) A well site shall demonstrate compliance by meeting the performance test methods and procedures specified in 40 CFR 60.5413a.

(3) VOC control devices and all associated equipment shall be inspected monthly by audio, visual, or olfactory (AVO) means to ensure the integrity of the equipment is maintained and is operational. If equipment is not operational, corrective action shall be taken within 15 days of discovery.

R307-508-4. Recordkeeping.

(1) The owner or operator shall keep and maintain records of the VOC control device's control efficiency guaranteed by the manufacturer. These records shall be retained for the life of the control equipment on site.

(2) The owner or operator shall keep and maintain records of the manufacturer's written operating and maintenance instructions. These records shall be retained for the life of the control equipment.

(3) The owner or operator shall keep and maintain records of the VOC control device AVO inspections. These shall be retained for a minimum of three years. These records shall include:

(a) the date of the inspection;

(b) the status of the control device and associated equipment; and

(c) date of corrective action taken, if applicable.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

State of Utah
Administrative Rule Analysis
Revised November 2021

NOTICE OF PROPOSED RULE		
TYPE OF RULE: New ___; Amendment _X__; Repeal ___; Repeal and Reenact ___		
	Title No. - Rule No. - Section No.	
Utah Admin. Code Ref (R no.):	**R307-509**	**Filing ID (Office Use Only)**
Changed to Admin. Code Ref. (R no.):	**R**	

Agency Information

1. Department:	Department of Environmental Quality	
Agency:	Division of Air Quality	
Room no.:		
Building:	MASOB	
Street address:	195 North 1950 West	
City, state and zip:	Salt Lake City, Utah 84116	
Mailing address:	P.O. Box 144820	
City, state and zip:	Salt Lake City, Utah 84114-4820	
Contact person(s):		
Name:	**Phone:**	**Email:**
Bo Wood	385-499-3416	rwood@utah.gov
Sheila Vance	801-518-3132	svance@utah.gov
Please address questions regarding information on this notice to the agency.		

General Information

2. Rule or section catchline:

R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements

3. Purpose of the new rule or reason for the change (Why is the agency submitting this filing?)**:**

These amendments are necessary to align current oil and gas rules with new data from studies and compliance inspections. These changes reflect more accurate emission calculations that indicate a previous underestimation of VOC emissions from tanks and other components. The proposed changes will ensure the protection of air quality standards and improve compliance with required emission controls.

4. Summary of the new rule or change (What does this filing do? If this is a repeal and reenact, explain the substantive differences between the repealed rule and the reenacted rule)**:**

The amended rule defines “shut-in or temporarily abandoned” wells, eliminates a previously granted exemption for those with an approval order issued under R307-401, modifies requirements for leak testing to require one test during the months of September, October, November, or December, that tests occur no more than seven months apart, and that testing occurs within seven days of a previously “shut-in” well becoming operational.

Fiscal Information

5. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:

A) State budget:

The fiscal impact from these amendments on the state budget for FY22, FY23, and FY24 is estimated to be between a benefit of $9,400 and a cost of $21,620. There are 94 facilities that have an exemption through their approval order and it’s their choice to either keep the approval order or switch to permit-by-rule. Cancelling an existing approval order requires producers to enroll in the permit-by-rule system. The one-time fee to cancel an approval order ranges from $220 to $550. This could increase state revenue by between $20,680 and $51,700, but is offset by the elimination of the $150 approval order annual fee per facility - $14,400 total. The number of facilities that will choose to move to the permit-by-rule system is unknown, but the incentive structure makes switching cost effective in less than 4 years. The exact cost for each facility to switch is also unknown, but DAQ anticipates that the fiscal impact on the state budget will fall within the range outlined above.

B) Local governments:

This rule change is not expected to have any fiscal impact on local governments.

C) Small businesses ("small business" means a business employing 1-49 persons)**:**

This rule change is not expected to have any fiscal impact on small businesses.

D) Non-small businesses ("non-small business" means a business employing 50 or more persons)**:**

This rule change is not expected to have any fiscal impact on non-small businesses.

E) Persons other than small businesses, non-small businesses, state, or local government entities ("person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an ***agency***)**:**

This rule change is not expected to have any fiscal impact on persons other than small businesses, non-small businesses, state, or local government entities.

F) Compliance costs for affected persons (How much will it cost an impacted entity to adhere to this rule or its changes?)**:**

This rule change will not have a compliance cost for affected persons.

G) Comments by the department head on the fiscal impact this rule may have on businesses (Include the name and title of the department head):

6. A) Regulatory Impact Summary Table (This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they will not be included in this table. Inestimable impacts will be included in narratives above.)

Regulatory Impact Table

Fiscal Cost	**FY2022**	**FY2023**	**FY2024**
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Cost	**$0**	**$0**	**$0**
Fiscal Benefits			
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Benefits	**$0**	**$0**	**$0**
Net Fiscal Benefits	**$0**	**$0**	**$0**

B) Department head approval of regulatory impact analysis:

The Executive Director of the Department of Environmental Quality, Kim Shelley, has reviewed and approved this fiscal analysis.

Citation Information

7. Provide citations to the statutory authority for the rule. If there is also a federal requirement for the rule, provide a citation to that requirement:

19-2-104		

Incorporations by Reference Information

(If this rule incorporates more than two items by reference, please include additional tables.)

8. A) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**

	First Incorporation
Official Title of Materials Incorporated (from title page)	
Publisher	
Date Issued	
Issue, or version	

B) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**	
	Second Incorporation
Official Title of Materials Incorporated (from title page)	
Publisher	
Date Issued	
Issue, or version	

Public Notice Information

9. The public may submit written or oral comments to the agency identified in box 1. (The public may also request a hearing by submitting a written request to the agency. See Section 63G-3-302 and Rule R15-1 for more information.)		
A) Comments will be accepted until (mm/dd/yyyy)**:**		5/31/2022
B) A public hearing (optional) will be held:		
On (mm/dd/yyyy)**:**	**At** (hh:mm AM/PM)**:**	**At** (place)**:**
May 24, 2022	1:00PM	https://meet.google.com/ozt-syme-rum?hs=122&authuser=0

10. This rule change MAY become effective on (mm/dd/yyyy)**:**	07/07/2022
NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date. To make this rule effective, the agency must submit a Notice of Effective Date to the Office of Administrative Rules on or before the date designated in Box 10.	

Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 302, 303, and 402. Incomplete forms will be returned to the agency for completion, possibly delaying publication in the *Utah State Bulletin* and delaying the first possible effective date.			
Agency head or designee, and title:	Bryce C. Bird, Director	**Date** (mm/dd/yyyy)**:**	

R307. Environmental Quality, Air Quality.
R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements.
R307-509-1. Purpose.

R307-509 establishes requirements for conducting leak detection and repairs at well sites to control emissions of volatile organic compounds.

R307-509-2. Definitions.

"Difficult-to-Monitor" means difficult-to-monitor as defined 40 CFR 60.5397a, which is incorporated by reference in R307-210.

"Fugitive emissions" are considered any visible emissions observed using optical gas imaging or a Method 21 instrument reading of 500 ppm or greater.

"Fugitive emissions component" means any component that has the potential to emit fugitive emissions of VOC, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems, thief hatches or other openings, compressors, instruments, and meters.

“shut-in or temporarily abandoned” means a well that is closed off such that it stops producing for longer than seven calendar days.

"Unsafe-to-Monitor" means unsafe-to-monitor as defined 40 CFR 60.5397a, which is incorporated by reference in R307-210.

R307-509-3. Applicability.

(1) R307-509 applies to each fugitive emissions component at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution and is required to control emissions in accordance with R307-506 and R307-507.

(a) A source meeting the requirements of 40 CFR 60.5397a is meeting the requirements of this rule.

(~~b~~2) R307-509 does not apply to a fugitive emissions component at a well that is shut in or temporarily abandoned. ~~Sources subject to R307-509, are subject until the well is shut in.~~

~~(c) R307-509 does not apply to a fugitive emissions component that is subject to an approval order issued under R307-401-8.~~

R307-509-4. Leak Detection and Repair Requirements.

(1) Applicable sources shall comply with the following:

(a) The owner or operator shall develop an emissions monitoring plan that shall be available upon request to review for each individual well site. At a minimum, the plan shall include:

(i) monitoring frequency;

(ii) monitoring technique and equipment;

(iii) procedures and timeframes for identifying and repairing leaks;

(iv) recordkeeping practices; and

(v) calibration and maintenance procedures for monitoring equipment.

(b) The plan shall address monitoring for difficult-to-monitor and unsafe-to-monitor components.

(c) The owner or operator shall conduct monitoring surveys on site to observe each fugitive emissions component for fugitive emissions.

(d) Monitoring surveys shall be conducted according to the following schedule:

(i) ~~No later than 365 days after January 1, 2018, or~~ ~~n~~ No later than 60 days after startup of production, as defined in 40 CFR 60 Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution~~, whichever is later~~.

(ii) Semiannually after the initial monitoring survey. Consecutive semiannual monitoring surveys shall be conducted at least four months apart and no more than seven months apart. A fugitive emission component subject to R307-509 in Duchesne and Uintah counties must perform one monitoring survey during the months of September, October, November or December.

(iii) Annually after the initial monitoring survey for "difficult-to-monitor" components.

(iv) As required by the owner or operator's monitoring plan for "unsafe-to-monitor" components.

(v) Within seven days of a well site becoming operational after being shut in or temporarily abandoned.

(e) Monitoring surveys shall be conducted using one or both of the following to detect fugitive emissions:

(i) Optical gas imaging (OGI) equipment. OGI equipment shall be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions source.

(ii) Monitoring equipment that meets U.S. EPA Method 21, 40 CFR Part 60, Appendix A.

(f) If fugitive emissions are detected at any time, the owner or operator shall repair the fugitive emissions component as soon as possible but no later than 15 calendar days after detection. If the repair or replacement is technically infeasible, would require a vent blowdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement shall be completed during the next well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 24 months, whichever is earlier.

(g) The owner or operator shall resurvey the repaired or replaced fugitive emission component no later than 30 calendar days after the fugitive emission component was repaired.

R307-509-5. Recordkeeping.

(1) The owner or operator shall maintain records of the emissions monitoring plan. These records shall be retained for the life of the well site.

(2) The owner or operator shall maintain records of the monitoring surveys, repairs, and resurveys. These records shall be retained for a minimum of three years.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

State of Utah
Administrative Rule Analysis
Revised November 2021

NOTICE OF PROPOSED RULE		
TYPE OF RULE: New ___; Amendment _X__; Repeal ___; Repeal and Reenact ___		
	Title No. - Rule No. - Section No.	
Utah Admin. Code Ref (R no.):	**R307-511**	**Filing ID (Office Use Only)**
Changed to Admin. Code Ref. (R no.):	**R**	

Agency Information

1. Department:	Department of Environmental Quality	
Agency:	Division of Air Quality	
Room no.:		
Building:	MASOB	
Street address:	195 North 1950 West	
City, state and zip:	Salt Lake City, Utah 84116	
Mailing address:	P.O. Box 144820	
City, state and zip:	Salt Lake City, Utah 84114-4820	
Contact person(s):		
Name:	**Phone:**	**Email:**
Bo Wood	385-499-3416	rwood@utah.gov
Sheila Vance	801-518-3132	svance@utah.gov
Please address questions regarding information on this notice to the agency.		

General Information

2. Rule or section catchline:

R307-511. Oil and Gas Industry: Associated Gas Flaring

3. Purpose of the new rule or reason for the change (Why is the agency submitting this filing?)**:**

These amendments are necessary to align current oil and gas rules with new data from studies and compliance inspections. These changes reflect more accurate emission calculations that indicate a previous underestimation of VOC emissions from tanks and other components. The proposed changes will ensure the protection of air quality standards and improve compliance with required emission controls.

4. Summary of the new rule or change (What does this filing do? If this is a repeal and reenact, explain the substantive differences between the repealed rule and the reenacted rule)**:**

This rule removes an applicability exemption previously granted to producing wells with an approval order issued under R307-401.

Fiscal Information

5. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:

A) State budget:

The fiscal impact from these amendments on the state budget for FY22, FY23, and FY24 is estimated to be between a benefit of $9,400 and a cost of $21,620. There are 94 facilities that have an exemption through their approval order and it's their choice to either keep the approval order or switch to permit-by-rule. Cancelling an existing approval order requires producers to enroll in the permit-by-rule system. The one-time fee to cancel an approval order ranges from $220 to $550. This could increase state revenue by between $20,680 and $51,700, but is offset by the elimination of the $150 approval order annual fee per facility - $14,400 total. The number of facilities that will choose to move to the permit-by-rule system is unknown, but the incentive structure makes switching cost effective in less than 4 years. The exact cost for each facility to switch is also unknown, but DAQ anticipates that the fiscal impact on the state budget will fall within the range outlined above.

B) Local governments:

This rule change is not expected to have any fiscal impact on local governments.

C) Small businesses ("small business" means a business employing 1-49 persons)**:**

This rule change is not expected to have any fiscal impact on small businesses.

D) Non-small businesses ("non-small business" means a business employing 50 or more persons)**:**

This rule change is not expected to have any fiscal impact on non-small businesses.

E) Persons other than small businesses, non-small businesses, state, or local government entities ("person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an ***agency***)**:**

This rule change is not expected to have any fiscal impact on persons other than small businesses, non-small businesses, state, or local government entities.

F) Compliance costs for affected persons (How much will it cost an impacted entity to adhere to this rule or its changes?)**:**

This rule change will not have a compliance cost for affected persons.

G) Comments by the department head on the fiscal impact this rule may have on businesses (Include the name and title of the department head):

6. A) Regulatory Impact Summary Table (This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they will not be included in this table. Inestimable impacts will be included in narratives above.)

Regulatory Impact Table

Fiscal Cost	**FY2022**	**FY2023**	**FY2024**
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Cost	**$0**	**$0**	**$0**
Fiscal Benefits			
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Benefits	**$0**	**$0**	**$0**
Net Fiscal Benefits	**$0**	**$0**	**$0**

B) Department head approval of regulatory impact analysis:

The Executive Director of the Department of Environmental Quality, Kim Shelley, has reviewed and approved this fiscal analysis.

Citation Information

7. Provide citations to the statutory authority for the rule. If there is also a federal requirement for the rule, provide a citation to that requirement:

19-2-104		

Incorporations by Reference Information

(If this rule incorporates more than two items by reference, please include additional tables.)

8. A) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**

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Official Title of Materials Incorporated (from title page)	
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Date Issued	
Issue, or version	

B) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**

	Second Incorporation
Official Title of Materials Incorporated (from title page)	
Publisher	
Date Issued	
Issue, or version	

Public Notice Information

9. The public may submit written or oral comments to the agency identified in box 1. (The public may also request a hearing by submitting a written request to the agency. See Section 63G-3-302 and Rule R15-1 for more information.)		
A) Comments will be accepted until (mm/dd/yyyy)**:**		5/31/2022
B) A public hearing (optional) will be held:		
On (mm/dd/yyyy)**:**	**At** (hh:mm AM/PM)**:**	**At** (place)**:**
May 24, 2022	1:00PM	https://meet.google.com/ozt-syme-rum?hs=122&authuser=0

10. This rule change MAY become effective on (mm/dd/yyyy)**:**	07/07/2022
NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date. To make this rule effective, the agency must submit a Notice of Effective Date to the Office of Administrative Rules on or before the date designated in Box 10.	

Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 302, 303, and 402. Incomplete forms will be returned to the agency for completion, possibly delaying publication in the *Utah State Bulletin* and delaying the first possible effective date.			
Agency head or designee, and title:	Bryce C. Bird, Director	**Date** (mm/dd/yyyy)**:**	

R307. Environmental Quality, Air Quality.
R307-511. Oil and Gas Industry: Associated Gas Flaring.
R307-511-1. Purpose.

R307-511 establishes control requirements for the flaring of produced gas associated with well sites.

R307-511-2. Definitions.

"Emergency release" means a temporary, infrequent and unavoidable situation in which the loss of gas is uncontrollable or necessary to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment. An "emergency" is limited to a short-term situation of 24 hours or less caused by an unanticipated event or failure that is out of the operator's control and is not due to operator negligence.

"Flaring" means use of a thermal oxidation system designed to combust hydrocarbons in the presence of a flame.

"Associated Gas" means the natural gas that is produced from an oil well during production operations and is either sold, re-injected, used for production purposes, vented (rarely) or flared. Low pressure gas associated with the working, breathing, and flashing of oil is not considered associated gas under this definition and shall be controlled in accordance with R307-506 and R307-507.

R307-511-3. Applicability.

(1) R307-511 applies to each producing well located at a well site as defined in 40 CFR 60.5430a Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) VOC control devices used for controlling associated gas are subject to R307-508.

~~(3) R307-511 does not apply to producing wells that are subject to an approval order issued under R307-401-8.~~

R307-511-4. Associated Gas Flaring Requirements.

(1) Associated gas from a completed well shall either be routed to a process unit for combustion, routed to a sales pipeline, or routed to an operating VOC control device except for emergency release situations as defined in R307-511-2.

R307-511-5. Recordkeeping.

(1) The owner or operator shall maintain records for emergency releases under R307-511-4(1)~~(a)~~.

(a) The time and date of event, volume of emissions and any corrective action taken shall be recorded.

(b) These records shall be kept for a minimum of three years.

KEY: air quality, nonattainment, offset
Date of Enactment or Last Substantive Amendment: March 5, 2019
Authorizing, and Implemented or Interpreted Law: 19-2-104; 19-2-108

6905 S. 1300 E. #288, Cottonwood Heights, UT 84047-1817

FUELING UTAH'S GROWTH & PROSPERITY

April 1, 2022

Members of the Utah Air Quality Board (by email):
Randy Martin, Chair - randy.martin@usu.edu
Cassady Kristensen, Vice-Chair - Cassady.Kristensen@riotinto.com
Michelle Bujdoso - mdbujdoso@marathonpetroleum.com
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Utah Division of Air Quality
P. O. Box 144820
Salt Lake City, UT 84114-4820

Subject: Comments from the Utah Petroleum Association on Agenda Item 4 for April 6 meeting of the Air Quality Board, Propose Oil and Gas Rulemaking for Public Comment

Dear Members of the Air Quality Board:

The agenda for the Air Quality Board meeting scheduled for April 6, 2022, includes Agenda Item 4, PROPOSE FOR PUBLIC COMMENT: Amend R-307-506, Oil and Gas Industry: Storage Vessel; R-307-508, Oil and Gas Industry: VOC Control Devices; R-307-509, Oil and Gas Industry: Leak Detection and Repair Requirements; and R-307-511, Oil and Gas Industry: Associated Gas Flaring.

In December 2021, the Utah Division of Air Quality (UDAQ) provided stakeholders with an advanced notice of the proposed rulemaking and, in response, the Utah Petroleum Association (UPA) submitted comments on the rulemaking in January 2022. UDAQ addressed some of our comments and provided feedback on why they did not address others. We appreciate having the opportunity to provide comments at that early stage in the rulemaking, the changes that UDAQ made based on our comments, and UDAQ's transparency of sharing their response to comment with us.

UPA is a statewide oil and gas trade association established in 1958 representing companies involved in all aspects of Utah's oil and gas industry. UPA members range from independent producers to midstream and service providers, to major oil and natural gas companies widely recognized as industry leaders responsible for driving technology advancement resulting in environmental and efficiency gains. UPA member companies will be affected by the rulemaking.

After submitting our January 2022 comments letter, we obtained additional information about the basis for the proposed changes to R307-506 regarding storage vessels. This letter discusses our evaluation of the additional information obtained. Our analysis shows the proposal attempts to set the threshold throughput level for storage vessels at an unjustifiably low level. We appreciate the opportunity to share this information with the Air Quality Board members. We have additional concerns with the implementation timing for all of the proposed rule changes and with the overly restrictive schedule proposed for leak monitoring as well as with other detailed aspects of the proposed rulemaking package. While we plan to submit additional comments to UDAQ during the formal comment period, we provide this letter to convey to the members of the Air Quality Board some of our most critical feedback.

UDAQ proposes to significantly lower the threshold storage vessel throughput level where air emission controls will be required on oil & gas storage vessels from the current level of 8,000 barrels per year (bpy) of throughput to the very low level of 3,200 bpy. The attached "Comment from the Utah Petroleum Association to the Air Quality Board Regarding Emission Factor for Determining the Control Threshold for Storage Vessels," explains our concerns in detail and shows that UDAQ based the new lower threshold on a faulty analysis to arrive at a conclusion that is not congruent with similar analyses by the Environmental Protection Agency. Instead of the proposed threshold of 3,200 bpy, UPA's analysis suggests that a more technically correct threshold would be 5,000 bpy.

In addition to our technical comments attached regarding the basis for the throughput threshold change, UPA is especially concerned about the timing to implement this change and other changes in the rule. UDAQ wants the changes to be implemented no later than January 1, 2023, a date that will be difficult and potentially impossible to meet in any situation and made even more so by the current labor and supply chain shortages. Oil and gas operators report that field projects previously requiring six months to design and construct now require a year or more. Utah's labor shortage is more acute than any other state nationwide because the unemployment rate in Utah is the lowest of all 50 states, tied with Nebraska at 2.1%.[1] The labor shortage will hamper operators' ability to comply in a timely manner.

The only option if operators cannot install the controls on time will be to shut in wells and drain the associated storage vessels of crude oil until they can install the newly required air emission controls. Utah's petroleum refineries process a significant amount of crude oil from the Uinta Basin. Shutting in wells in this way will increase the strain on the present shortage of crude oil and will tend to drive gasoline and diesel prices even higher. This will further exaggerate the "pain at the pump" felt by Utah residents and cause potentially damaging effects especially to those with lower incomes.

The current crude oil shortage and fuels pricing has attracted the attention of Governor Cox. On March 25, the Governor met with energy executives from across Utah to evaluate the recent increases in crude oil price and any potential ways to mitigate the situation through encouraging additional production. This rulemaking unnecessarily flies in the face of the Governor's objectives. Set at an appropriate throughput level, this rule could both allow continued growth of Utah crude to help address the state's high fuel prices whiles also effectively protecting air quality.

[1] See U.S. Bureau of Labor Statistics webpage at https://www.bls.gov/web/laus/laumstrk.htm. Data quoted are the most recent available as of this writing (accessed on March 29, 2022), updated on March 25, 2022, and based on seasonally adjusted unemployment rates for February 2022.

While the threshold throughput level for air emission controls on storage tanks and the very short implementation timing pose our two greatest concerns with the rulemaking package, we have other concerns as well. Another critical concern lies with the restrictive requirements for scheduling Leak Detection and Repair (LDAR) monitoring. In response to our January 2022 comments, UDAQ provided a bit of added flexibility but overall complying with the proposed rule will result in an overly restrictive set of requirements that will increase costs for operators but for which UDAQ has not quantified the benefit. Costs will increase because operators will incur months where they will not be able to do any monitoring, thus resulting in down time for monitoring staff and a higher monitoring workload requiring increased staffing levels in other months. Yet, the fiscal information provided indicates the rule change is not expected to have any fiscal impact on small or non-small businesses. We do not agree with this fiscal analysis. Managing to an overly restrictive and non-uniform schedule will drive costs up with only a marginal air quality benefit at best. Furthermore, the restrictive requirements will discourage operators from voluntarily increasing their monitoring schedule from semi-annual to quarterly, as some Uintah Basin operators have done, because the added voluntary monitoring could make the schedule even more difficult to manage.

We plan to provide these and additional comments on the proposed rule to UDAQ during the formal comment period. We thank you for your consideration of our concerns.

Sincerely,

Rikki Hrenko-Browning
President, Utah Petroleum Association

cc: Bryce Bird, bbird@utah.gov
Becky Close, bclose@utah.gov
Sheila Vance, svance@utah.gov
Melissa Yazhe, myazhe@utah.gov

Attachment: “Comment from the Utah Petroleum Association to the Air Quality Board Regarding Emission Factor for Determining the Control Threshold for Storage Vessels”

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FUELING UTAH'S GROWTH & PROSPERITY

Comment from the Utah Petroleum Association to the Air Quality Board Regarding Emission Factor for Determining the Control Threshold for Storage Vessels

In 2018, the Environmental Protection Agency (EPA) designated the Uinta Basin (UB) as an ozone nonattainment area for the 2015 ozone National Ambient Air Quality Standard (NAAQS). Although ozone formation most commonly occurs in the summertime, the UB has rare wintertime ozone formation which occurs when wintertime atmospheric inversions trap nitrogen oxide (NOx) and volatile organic compound (VOC) emissions within the basin topography and, in the presence of snow cover, can have enough sunlight reflected off the snow for the emissions to react and form ozone. The oil and gas industry provides most of the NOx and VOC emissions within the UB and storage vessels for oil are a source of VOC emissions.

Under a current State of Utah rule adopted in 2018, R-307-506, storage vessels with 8,000 barrels per year (bpy) of throughput or more must have air emission controls to reduce the amount of VOC emissions from the storage vessel to the air. UDAQ determined the throughput threshold for controls by estimating the throughput that would equate to 4.0 tons per year (tpy) of VOC emissions, a level that UDAQ considers Best Available Control Technology (BACT) and cost-effective. Now, UDAQ has more data available, data that came from the recent "VOC Composition Study" and proposes to significantly reduce the threshold for controls in the rule from the current level of 8,000 bpy to a much lower value, 3,200 bpy, again estimated to correspond to 4.0 tons per year of VOC emissions but based on the more recent extensive dataset from the Study. UDAQ based their proposed lower threshold on their own recently created VOC emission factor of 2.5 pounds per barrel (lb/bbl) which they developed in a faulty manner as explained in this document.

EPA, on the other hand, established their own federal tank emission control rules, New Source Performance Standards OOOO and OOOOa, based on their finding that controlling tanks with 6.0 tpy of emissions would be cost-effective. EPA developed their rules based on a crude oil VOC emission factor of 1.6 lb/bbl[2] established from a study that measured actual VOC emissions from crude oil storage tanks in Texas,[3] where oil tends to have higher emissions and therefore higher emission factors than the waxy, viscous crude oil from the Uintah Basin. EPA's control requirements equate to an effective control threshold of 7,500 bpy of crude oil throughput.[4]

In other words, at least three aspects of UDAQ's analysis are incongruent with EPA's analysis, namely:

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[2] Environmental Protection Agency, July 2011. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards. EPA-453/R-11-002.

[3] Texas Environmental Research Consortium, October 31, 2006, revised April 2, 2009. VOC Emissions from Oil and Condensate Storage Tanks, Final Report.

[4] (6 tons VOC/year x 2000 lbs/ton ÷ 1.6 lb VOC/bbl = 7,500 bpy.

1. The lower emissions level for cost-effectiveness of 4.0 tpy compared to 6.0 tpy
2. The higher emission factor of 2.5 lb/bbl for waxy, viscous crude oil (and higher estimated emissions) compared to 1.6 lb/bbl measured for lighter Texas oil
3. The very low threshold throughput level for air emission controls of 3,200 bpy compared to 7,500 bpy

UDAQ has not explained why they continue to use a cost-effectiveness level of 4.0 tpy compared to EPA's 6.0 tpy.

Moreover, the proposed control threshold of 3,200 bpy would require many "stripper wells" to have controls installed. The Utah Code allows certain economic benefits to stripper wells, defined as wells producing 20 barrels or less of crude oil per day on average during any consecutive 12-month period,[5] in other words, 7,300 bpy, because these wells would otherwise be marginally economic or uneconomic to operate. Imposing additional air emission controls on these wells reduces the economics of operating them.

UDAQ used a faulty analysis to arrive at 3,200 barrels per year (bpy) for the proposed throughput threshold to require controls on oil storage vessels. Typically, a poorly correlated dataset such as this one should not be used to produce a single emission factor. The low correlation of this dataset could be due to procedural sampling variations, legitimate difference to the reservoir or formation being extracted from, differences in equipment and facilities design, and operating condition differences. We have little information to inform why this dataset has such a poor correlation and therefore whether some or all the data should or should not be relied upon. However, we understand, accept, and appreciate UDAQ's desire to use a single emission factor to determine a threshold for controls for simplicity in compliance determinations. Nonetheless, in addition to a lack of confidence in whether the sample data is representative, the methodology used to calculate the throughput threshold proposed is flawed. We recommend a threshold of 5,000 bpy as explained below.

UDAQ plotted all the data that passed their acceptance criterion (accepted data) and applied a linear fit correlation equation to calculate the storage vessel threshold throughput level for controls, arriving at 3,200 bpy and an emission factor of 2.5 pounds per barrel. The statistical value R^2 (pronounced "R squared") provides evidence of the degree of correlation of a dataset. Statistically, R^2 is a value between 0 and 1.0 and in general the closer that R^2 is to 1.0, the better correlated the data. For example, an R^2 of 0.6 shows that 60% of the data fit the correlation. For this set of data in the manner that UDAQ used it for the rulemaking, R^2 equals 0.51, indicating a relatively poor correlation between the points in the dataset, essentially a 51% likelihood that the data fit the linear relationship applied or alternatively a 49% likelihood that the data do not fit the applied linear relationship. The red highlighted row on **Table 1** summarizes UDAQ's correlation and results.

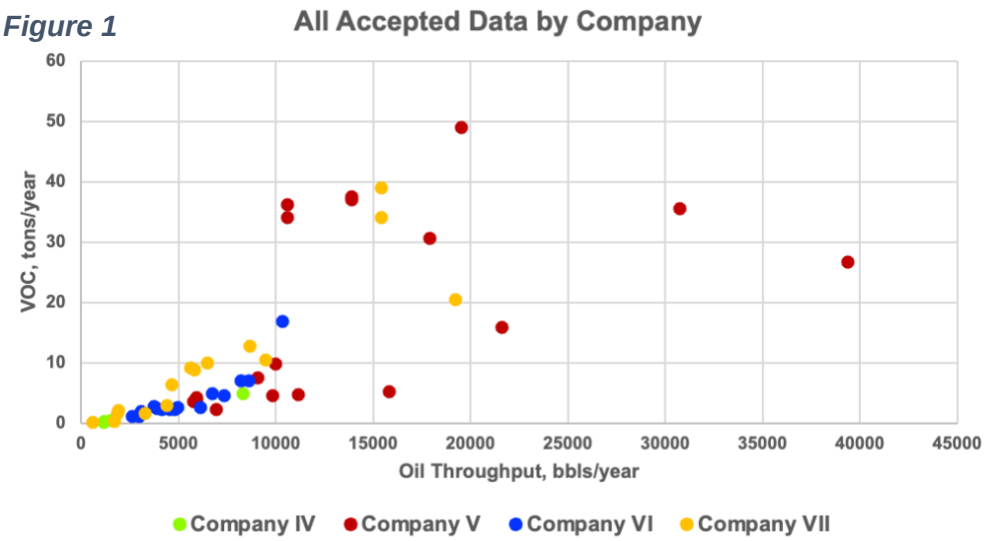
[5] Utah Code Title 59, Chapter 5, Part 1, Section 102(2)(b)(ii)(A).

Table 1

Throughput Calculation for 4 tpy, bbls			
Sample description for Accepted Data	**R^2**	**Emission Factor**	**Control Threshold, bbls/yr**
Oil throughput ≤8,000 bbl/year			
Intercept ≠ zero	0.47	1.5	5279
Intercept = zero	0.77	1.6	5000
Oil throughput ≤10,000 bbl/year			
Intercept ≠ zero	0.61	1.6	4912
Intercept = zero	0.84	1.6	5000
All oil			
Intercept ≠ zero	0.51	2.5	3138
Intercept = zero	0.71	2.6	3077

Most importantly, the data for storage vessels with high throughputs is flawed because it is widely scattered, as shown in **Figure 1**. The scatter in the data shows a systematic shift between the data less than and greater than 10,000 bpy but UDAQ has not identified the reasons for this shift to our knowledge. The reasons could be very important to understanding the potential relevance of the higher throughput data.

Figure 1



As illustrated in **Figure 1**, eleven of the fifteen scattered data points with throughputs greater than 10,000 bpy are notably from a single company, Company V, suggesting a systematic difference in some of the operations of this company (e.g., formation, reservoir, design, operation, or something else unexplained). In the absence of an adequate explanation, including these highly scattered data points in the analysis to define the threshold throughput for requiring controls is not appropriate and does not comply with statistical best practices.

We also examined the flash gas emission factor as a function of separator pressure. The flash gas emissions factor represents the emissions associated with dropping the pressure of the liquid from the upstream gas/liquid separator to local atmospheric pressure in the storage vessel. Higher separator pressures leave more lighter compounds in the liquid flowing to the storage

vessel, resulting in greater emissions from the storage vessel at atmospheric pressure. **Figure 2** shows that the emission factor increases exponentially with separator pressures greater than 80 psia and samples from Company V comprise most samples in this range, five of seven. A close examination of the data shows that all seven samples with pressures greater than 80 psia including the five from Company V coincidentally have throughput greater than 10,000 bpy, as shown in **Table 2**. Thus, separator pressure may be one factor in the greater emissions from Company V and reinforces that these samples are outliers and should not be included in any generalized emission factor correlations for regulatory purposes, especially for storage vessels with lower throughputs.

Figure 2 **Variation of Storage Vessel Flash Gas Emission Factor with Sample Pressure**

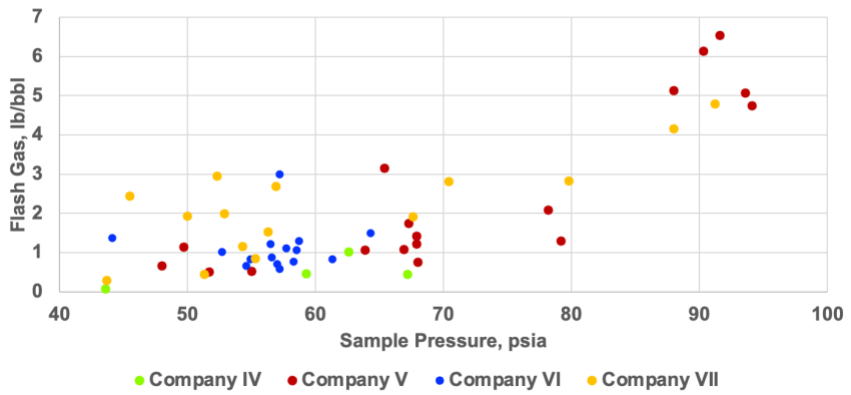


Table 2

Samples > 80 psia			
Company	**Emission Factor, lb/bbl**	**Sample Pressure, psia**	**Storage Vessel Throughput, bpy**
V	4.74	94.1	19540
V	5.13	88.0	13879
V	5.07	93.6	13879
V	6.13	90.3	10591
V	6.54	91.6	10591
VII	4.79	91.2	15402
VII	4.16	88.0	15402

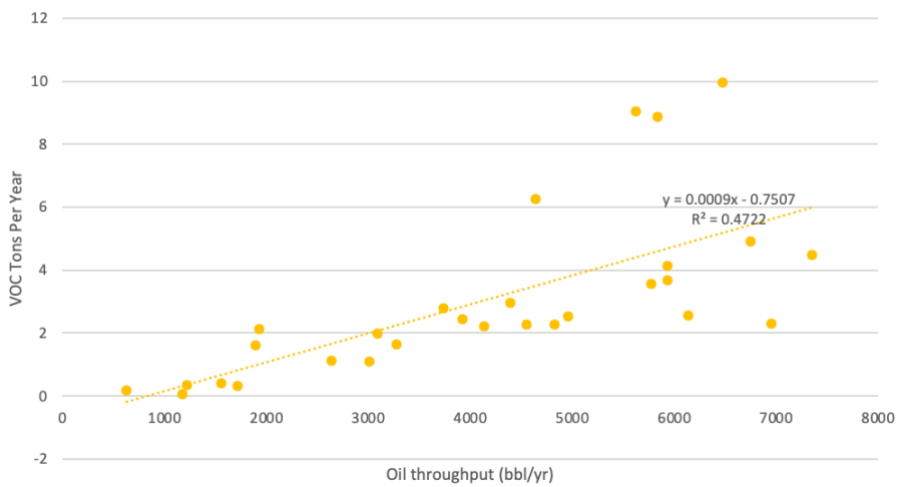
Moreover, the highly scattered data at higher throughputs is irrelevant for this determination because storage vessels above 8,000 bpy already require controls and will remain controlled in any scenario. The allowed emissions from these storage vessels over 8,000 bpy are already limited in the associated Approval Order (AO) or by the Permit by Rule (PBR).

As shown in **Table 1**, using only the data for storage vessels less than 10,000 bpy throughput, the R^2 value increases to 0.61, indicating a better correlated set of data.

Another error in UDAQ's analysis is that UDAQ's correlation equations show storage vessels with very low throughputs as having negative emissions, an impossibility. This occurs because UDAQ did not set the intercept of the correlation equations to zero. In other words, storage vessels with no throughput should have zero emissions and a zero intercept in these graphs. Instead of

setting the intercept to zero, UDAQ's correlation equations have negative intercepts, thus indicating negative emissions at low throughput, and a steeper slope to the line for the correlation equation, suggesting lower emissions at lower throughputs and higher emissions at higher throughputs. The "negative emissions" are most pronounced in UDAQ's plot of storage vessels with less than 8,000 bpy throughput as shown in **Figure 3**. This phenomenon also occurs in the dataset used to set UDAQ's proposed threshold of 3,200 bpy albeit to a lesser degree.

Figure 3 Oil tank TPY (flash, wb) - acceptance criteria applied - only less than 8000 bbls



Alternatively, UPA recommends setting the intercept to zero for the correlation equations. Making this change improves the R^2 for the full accepted dataset used in setting the proposed regulatory threshold (including the data above 10,000 bpy) from an R^2 of 0.51 to 0.71, as shown in **Table 1** in the row just below the row highlighted red. **Table 1** also shows that if the dataset instead focuses on only those tanks that are not controlled, those under 8,000 bpy, and the intercept correctly set at zero, the R^2 of the data set improves even more to 0.77.

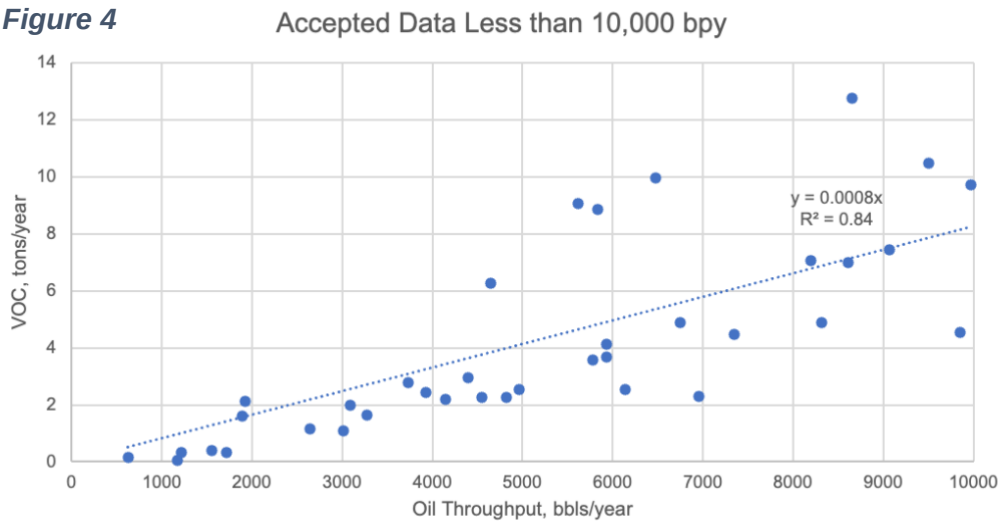
UPA recommends the following changes to the methodology of determining the correlation equation and setting the storage vessel throughput threshold for requiring controls:

1. Use only the accepted data points for storage vessels with less than 10,000 bpy throughput and do not use any of the data points above 10,000 bpy because they are widely scattered due to an unknown reason and irrelevant to the threshold determination as they are already controlled.

2. Set the intercept at zero to prevent the impossible situation of having an equation that predicts negative emissions at low throughput levels.

We recommend using the data less than 10,000 bpy because it comprises the best correlated and un-scattered dataset. As shown below in **Figure 4** and above in the green highlighted row of **Table 1**, this methodology and dataset results in the best R^2 value, 0.84, and a throughput threshold for controls of 5,000 bpy.

Figure 4



Furthermore, we understand that the proposed rule allows site-specific sampling to set a site-specific throughput threshold for controls. However, we have been working with UDAQ and EPA to arrive at mutually acceptable sampling guidance since last July and have not yet arrived at an agreement. UDAQ recently indicated it may not accept samples previously obtained, even though the methodology used to obtain those samples has in fact been accepted in the past and is accepted in other states. Moreover, we have no guarantee UDAQ will accept future samples obtained through proven quality-controlled and quality-checked methods used widely throughout the oil industry as there is no agreement on the sampling guidance and previously accepted samples are now being rejected. Especially considering the very short time fuse for compliance with the proposed rule change, UPA finds little or no comfort in the site-specific sampling provision for existing storage vessels.[6]

Table 1 summarizes the calculations with UDAQ's results highlighted in red and our recommended results highlighted in green.[7] The high R^2 and exclusion of irrelevant scattered high-throughput data justifies the use of the green highlighted result. The throughput threshold for required controls on storage vessels should be no less than 5,000 bpy.

[6] UPA supports retaining the site-specific sampling provision in the rule because it will eventually be helpful for new sites in the future when we have mutually acceptable sampling guidance.
[7] We included results for throughput less than or equal to 8,000 bpy for completeness since UDAQ's analysis considered this cut point for data used in their evaluation.

ITEM 5

State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-032-22

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Chelsea Cancino, Environmental Scientist

DATE: March 24, 2022

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Utah State Implementation Plan. Section XX.A: Regional Haze Second Implementation Period; Utah State Implementation Plan. Emission Limits and Operating Practices: Section IX, Part H.21 and Part H.23; R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits; and R307-110-28. Regional Haze.

The Regional Haze State Implementation Plan (SIP) for the second planning period addresses requirements for periodic comprehensive revisions of implementation plans for regional haze (RH). The Regional Haze Rule (RHR) requires Utah to address RH in each mandatory Class I Area (CIA) located in Utah and in each mandatory CIA located outside of Utah that may be affected by pollutants emitted from sources within Utah. Utah is required to submit a SIP revision to the EPA addressing the specific elements required by the rule.

The objectives of the RHR are: 1) to improve existing visibility in 156 national parks, wilderness areas, and monuments 2) to prevent future visibility impairment by manmade sources, and 3) to meet the national goal of natural visibility conditions in all mandatory CIAs by 2064. Utah's CIAs are Arches National Park, Bryce Canyon National Park, Canyonlands National Park, Capitol Reef National Park, and Zion National Park.

The RHR establishes several planning periods extending from 2005 to 2064. The State of Utah is required to develop an 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 to the EPA on July 31, 2018. However, the deadline was extended to July 31, 2021. In this revision, UDAQ demonstrates the visibility progress to date in each of Utah's CIAs and analyzes Utah's

emissions trends and sources of visibility impairment. Utah is required to set reasonable progress goals which:

1) must provide for an improvement in visibility for the most impaired days throughout the implementation plan, and

2) ensure no degradation in visibility for the least impaired days over the same period.

For this purpose, Utah has outlined its Long-Term Strategy (LTS) in this document as well as the 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-state CIAs. 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.

Throughout this second implementation period, UDAQ has participated in the WRAP, which has conducted modeling and technical analysis to support 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.

This SIP revision also examines the need to implement additional emission reduction measures on sources that are reasonably anticipated to contribute to visibility impairment. The examination required to determine actions for this period is known as a four-factor analysis and consists of four criteria each selected source must consider when analyzing the possible installation of controls: 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts, and 4) remaining useful life.

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, PacifiCorp, 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 this second implementation period. UDAQ has received each facility's four-factor analysis, provided each with an evaluation of their analysis, and received evaluation responses from each. After consideration of the information provided, as well as the modeling results provided by the WRAP, UDAQ has made reasonable progress determinations for each facility.

The actions deemed necessary for reasonable progress to be made in Utah's CIAs for this implementation period consist of establishing a firm closure date for units 1 and 2 of the Intermountain Generation Station, setting mass-based emissions limits for PacifiCorp's Hunter and Huntington Power Plants, and requiring the installation of a Flue Gas Recirculation (FGR) unit on the Riley Boiler at US Magnesium's Rowley Plant. The emissions limits proposed for PacifiCorp ensure their emissions do not exceed their modeled or recent actual emissions levels to maintain Utah's 2028 "on-the-books" projections as modeled by WRAP to ensure reasonable visibility progress at Utah's CIAs by the end of this implementation period.

Recommendation: Staff recommends that the Board propose the Utah SIP, Section XX.A: Regional Haze Second Implementation Period; Utah SIP, Emission Limits and Operating Practices: Section IX, Part H.21 and Part H.23; R307-110-17, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits; and R307-110-28, Regional Haze, for a 30-day public comment period.

Utah State Implementation Plan

Regional Haze Second Implementation Period

Section XX.A

[Date]

List of tables

List of figures

List of acronyms

BACT	Best Available Control Technology
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
SOx	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 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-

[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 progress to date
[6] See chapter 5 for 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 examines the need to implement additional emission reduction measures on sources which are reasonably anticipated to contribute to visibility impairment. The examination required to determine actions 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, PacifiCorp, 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, and received evaluation responses from each. After consideration of the information provided, as well as the modeling results provided by the WRAP, UDAQ has made reasonable progress determinations[13] for each facility. The actions deemed necessary for reasonable progress to be made in Utah's CIAs for the purposes of this implementation period consist of establishing a firm closure date for units 1 and 2 of the Intermountain Generation Station, setting mass-based emissions limits for PacifiCorp's Hunter and Huntington Power Plants, and requiring the installation of a Flue Gas Recirculation (FGR) unit on the Riley Boiler at US Magnesium's Rowley Plant. The emissions limits proposed for PacifiCorp ensure their emissions do not exceed their modeled or recent actual emissions levels for the purposes of maintaining Utah's 2028 "on-the-books" projections as modeled by WRAP in order to ensure reasonable visibility progress at Utah's CIAs by the end of this implementation period.

[9] See chapter 3 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 chapter 9 for Utah's reasonable progress determinations

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.[14] In 2000, Utah established Sulfur Dioxide (SO_2) milestones with an Annex[15] 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[16] 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[17] along with a revision in 2019[18]. 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)[19]. 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.

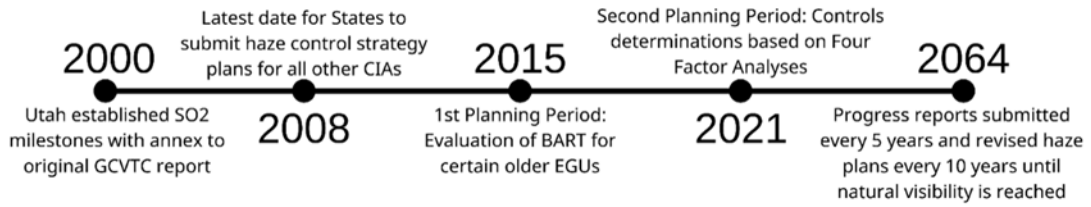


Figure 1: Regional Haze Timeline option for GCVTC areas

[14] The original 1996 report of The Grand Canyon Visibility Transport Commission can be found at https://www.phoenixvis.net/PDF/GCVTCFinal.pdf
[15] 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
[16] 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
[17] 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
[18] 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
[19] 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"[20] 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.[21]

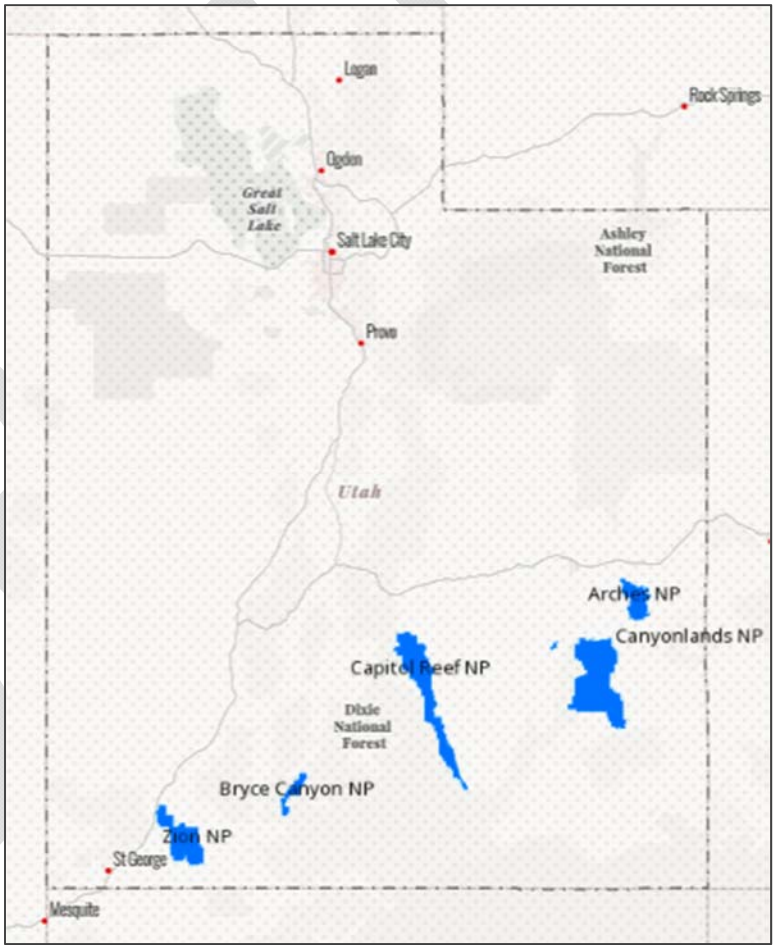


Figure 2: Map of Utah CIAs

[20] 42 U.S.C.A. § 7491(a)(1) (West).
[21] Statistics for all the National Parks discussed in this section come from the NPS Stats website at: https://irma.nps.gov/STATS/

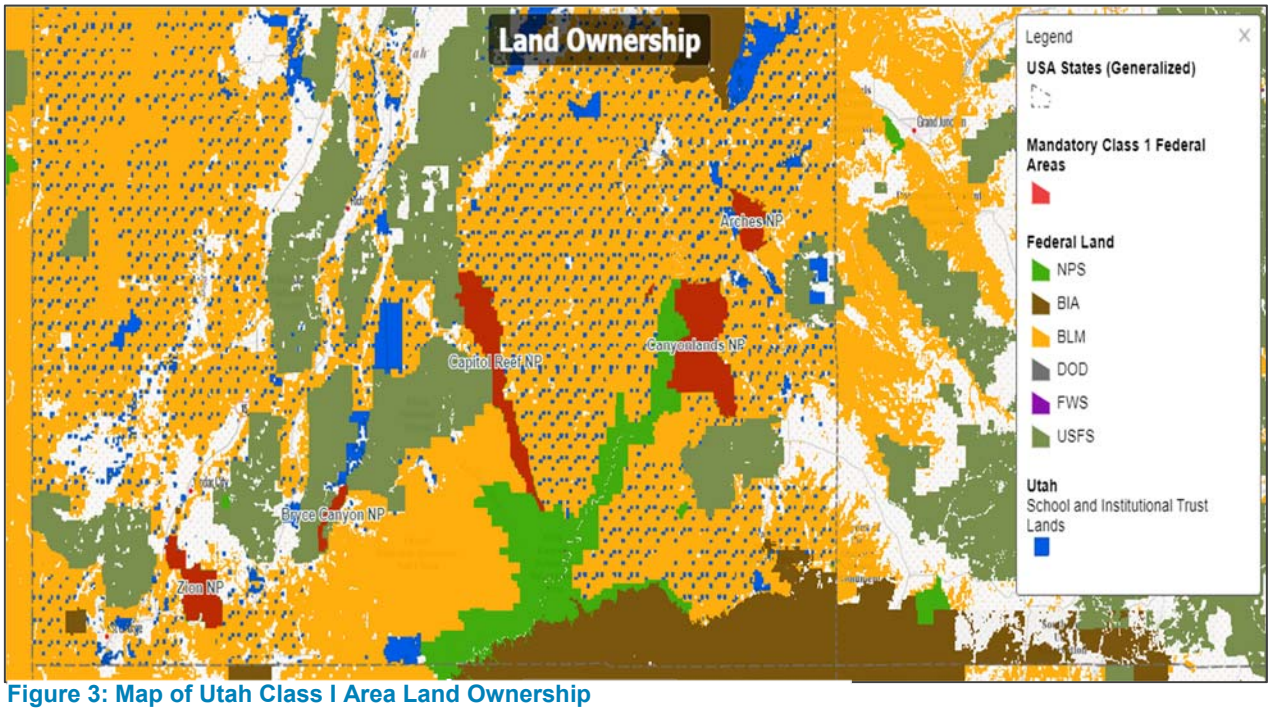


Figure 3: Map of Utah Class I Area Land Ownership

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."[22] 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.[23] Over the past 10 years, park visitation has increased, on average, five% each year.[24] The largest population center near Arches National Park is Moab. This town of over 5,300 residents[25] 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."[26] 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.[27]

Figure 5: Bryce Canyon National Park

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

[28] 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[29] and offers many hiking and backpacking opportunities, including 71 campsites.

1.B.5 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.[30] The park's 147,243 acres contain the Zion Canyon which is 15 miles long and 2,640 feet tall.[31] 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."[32] 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.

Figure 8: Zion National Park

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

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

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

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, 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.

Figure 9: Monitoring station for Capitol Reef National Park

1.D Monitoring Strategy[33]

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

[33] 40 CFR 51.308(f)(6) (IMPROVE PROGRAM)

visibility, and help determine the causes and sources of visibility impairment in CIAs. The network is comprised of 110 monitoring sites across the nation[34], 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. Figures 10 through 12 show three of Utah's monitoring stations.

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.[35] 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 10: Monitoring station for Bryce Canyon National Park

Figure 11: Monitoring station for Canyonlands and Arches National Park

[34] Shown in ta 13

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

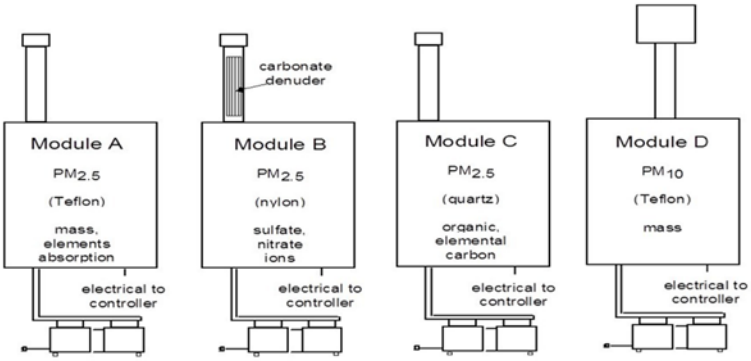


Figure 12: Monitoring station layout

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.

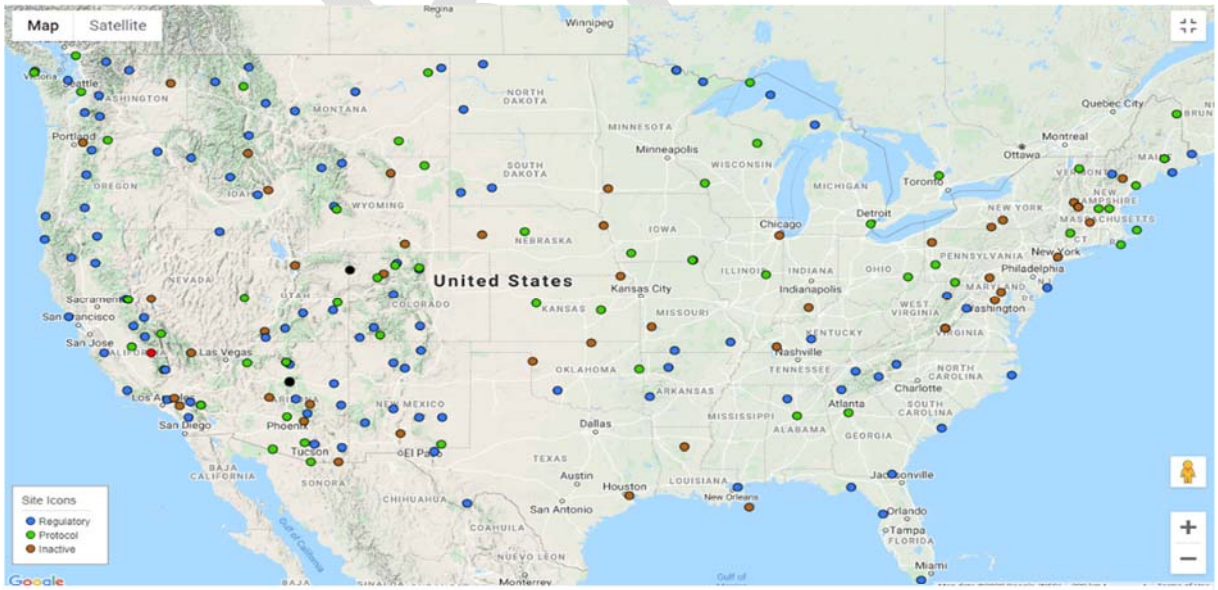


Figure 13: IMPROVE monitoring sites

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."[36]

When the CAA was amended in 1990, Congress added Section 169B,[37] authorizing further research and regular assessments of the progress to improve visibility in the mandatory CIAs.[38]

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

[36] 42 U.S.C.A. § 7491.
[37] *See id*. § 7492.
[38] 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.

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.[39] 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, 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

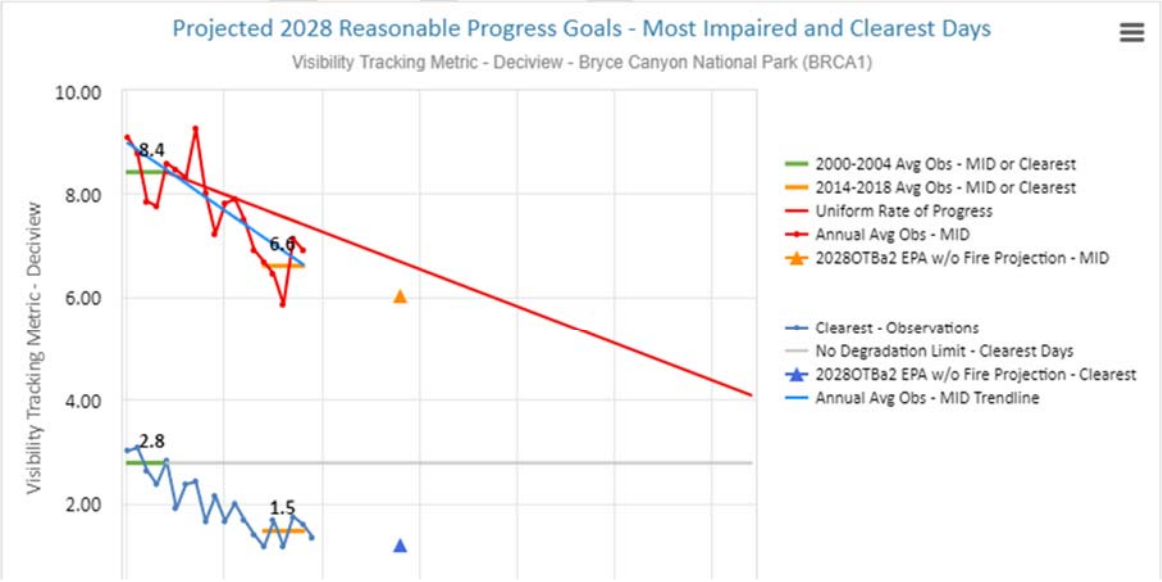


Figure 15: Regional haze glidepath for Bryce Canyon National Park tracking progress towards natural conditions in 2064

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

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.[40]

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;
- 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.[41] 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

[40] The Grand Canyon Visibility Transport Commission. Recommendations for Improving Western Vistas (June 10, 1996) available at https://www.phoenixvis.net/PDF/GCVTCFinal.pdf
[41] Regional Haze Regulations, 62 Fed. Reg. 41138 (July 31, 1997) (proposed rule).

into the regional haze regulations. WGA approved the stakeholders' recommendation and transmitted it to EPA in June 1998.[42] 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.[43]

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-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.[44] The WRAP has completed a suite of products to support states and tribes developing GCVTC-based regional haze implementation plans.[45]

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

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

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

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.[46] 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.[47]

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.

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.[48] 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.[49] To replace the disapproved BART alternative, EPA

[46] *See Ctr. for Energy & Econ. Dev. v. E.P.A.*, 398 F.3d 653 (D.C. Cir. 2005)
[47] *See* Regional Haze Regulations, 71 Fed. Reg. 60,612, 60,631 (Oct. 13, 2006), codified at 40 C.F.R. pt. 51.
[48] *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).
[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;

promulgated a FIP, requiring installation of Selective Catalytic Reduction (SCR) controls on the subject EGUs by August of 2021.[50]

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.[51] 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.[52] 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.[53] Utah revised the disapproved SIP to include this additional technical analysis and, after 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.[54]

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.[55] 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.[56] EPA's November 27, 2020 final rule is currently challenged in the Tenth Circuit by the conservation organizations (HEAL Utah,

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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.

[50] *See id*., 81 Fed. Reg. at 43907.

[51] *See Utah v. E.P.A. et al.*, No. 16-9541 (10th Cir. Sept. 1, 2016).

[52] *See* Section 1.E.7 below for additional details.

[53] 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. 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.").

[54] *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).

[55] 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.

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

National Parks Conservation Association, Sierra Club, and Utah Physicians for a Healthy Environment).[57] The lawsuit was filed on January 19, 2021.[58]

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[59] 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.[60]EPA issued final approval of the 2019 SIP revision on November 27, 2020 with effective date of December 28, 2020.[61] 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)."[62] With the final approval, EPA also found that "Utah's SIP fully satisfies the requirements of section 309 of the Regional Haze Rule and therefore the State has fully complied with the requirements for reasonable progress, including BART, for the first implementation period."[63]

1.F General Planning Provisions

1.F.1 Regional Haze Program Requirements

The program requirements of the RHR[64] 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).

[57] *See HEAL Utah et al. v. E.P.A. et al.*, No. 21-9509 (10th Cir. Jan 19, 2021).
[58] *See* Petition for Review, *HEAL Utah et al.*, No. 21-9509 (10th Cir. Jan. 19, 2021).
[59] 40 CFR 51.308€ (3)
[60] *See* 85 Fed. Reg. 3558.
[61] *See* 85 Fed. Reg. 75860.
[62] *Id.*, 85 Fed. Reg. at 75861.
[63] *Id.*
[64] 40 CFR 51.308

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 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[65], 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.

Indian Tribes: Air Quality Planning and Management, 63 Fed. Reg. 7254 (Feb. 12, 1998).

1.F.3 Utah Statutory Authority

The Utah Air Conservation Act[66] gives the Utah Air Quality Board authority to make rules pertaining to air quality activities.[67]

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.

[66] Utah Code Ann. §§ 19-2-101 through 19-2-304 (West 2021).
[67] *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,[68] 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 X, X, 2022.

2.A WRAP Engagement

During this second planning period, the WRAP Regional Haze Planning Work Group (RHPWG)[69] 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)

[68] 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).
[69] 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.[70] 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.[71] 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.[72] 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.[73] 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.[74] The opportunity for consultation must also be provided no less than 60 days prior to said public hearing or public comment opportunity.[75]

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

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.[77]

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[78].

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

[76] *See id.*, § 51.308(i)(2)(i) and (ii).
[77] *See id.*, § 51.308(i)(1)(i) and (ii).
[78] 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.[79]

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[80]

The RHR[81] 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[82]. BART for SO_2 is addressed through an alternative program[83] 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

[79] 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
[80] (40 CFR 51.308(g)(1))
[81] 40 CFR 51.308(e) and 40 CFR 51.309(d)(4)(vii)
[82] 40 CFR 51.308(e)(2) and (3)
[83] 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[84]

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[85]

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

[84] (40 CFR 51.308(g)(2)(5))
[85] (40 CFR 51.308(g)(3))

3.A.4 Analysis of any changes in emissions from all sources and activities within the state[86] [87]

The following figures[88] show Utah's statewide total emissions trends by sector from 1999 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.

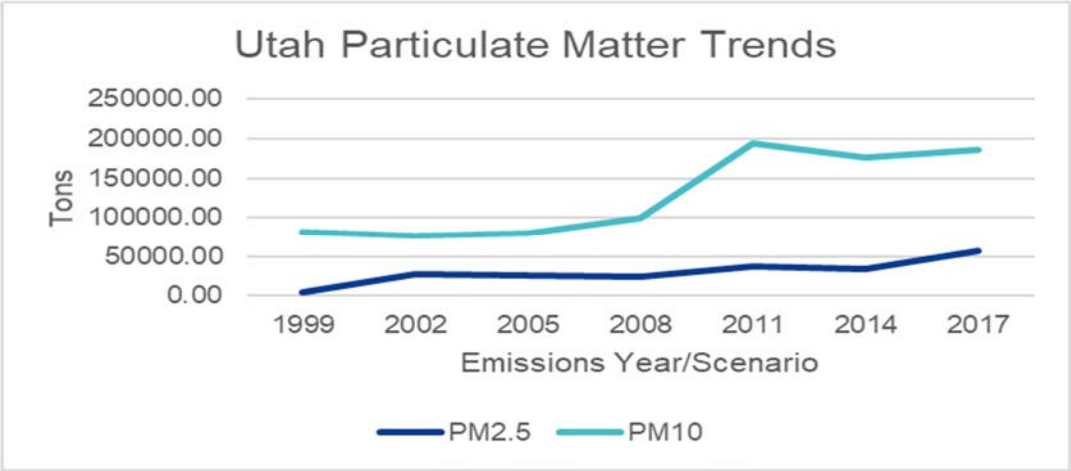

Figure 16: Utah PM Emissions Trends

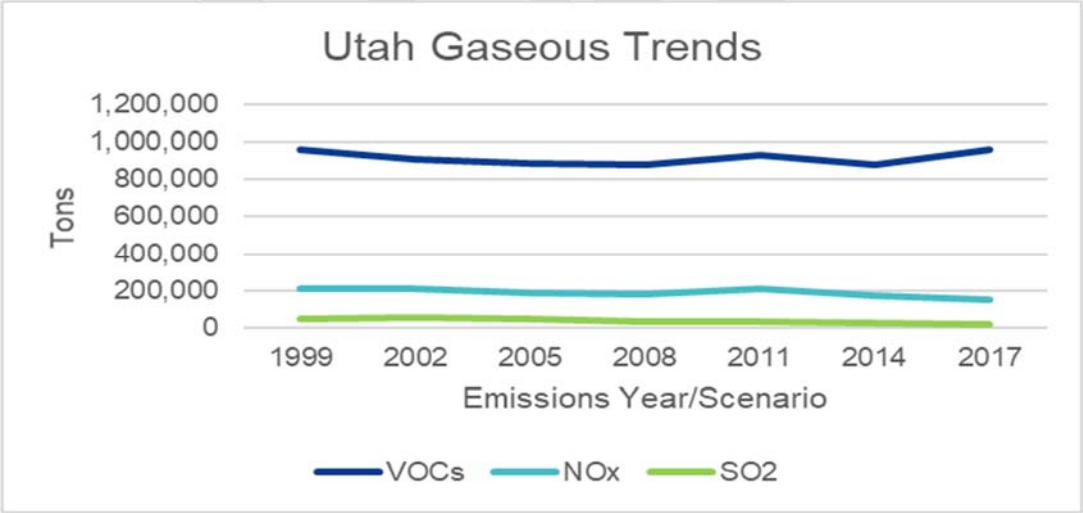

Figure 17: Utah Gaseous (NO_x, SO_2, and VOC) Emissions (w/o biogenics)

[86] (40 CFR 51.308(g)(4))
[87] These graphs use WRAP modeling data from scenarios 2014v2, RepBase2, and 2028Ota2. For area source calculations, the WRAP categories Oil and Gas – Non-Point, Residential Wood Combustion, Fugitive Dust, Agriculture, Remaining Non-Point, Agricultural Fire, and Wildland Prescribed Fire were added. For Non-Road Mobile sources, the categories Non-Road Mobile and Rail were added.
[88] See figures 10-14 below

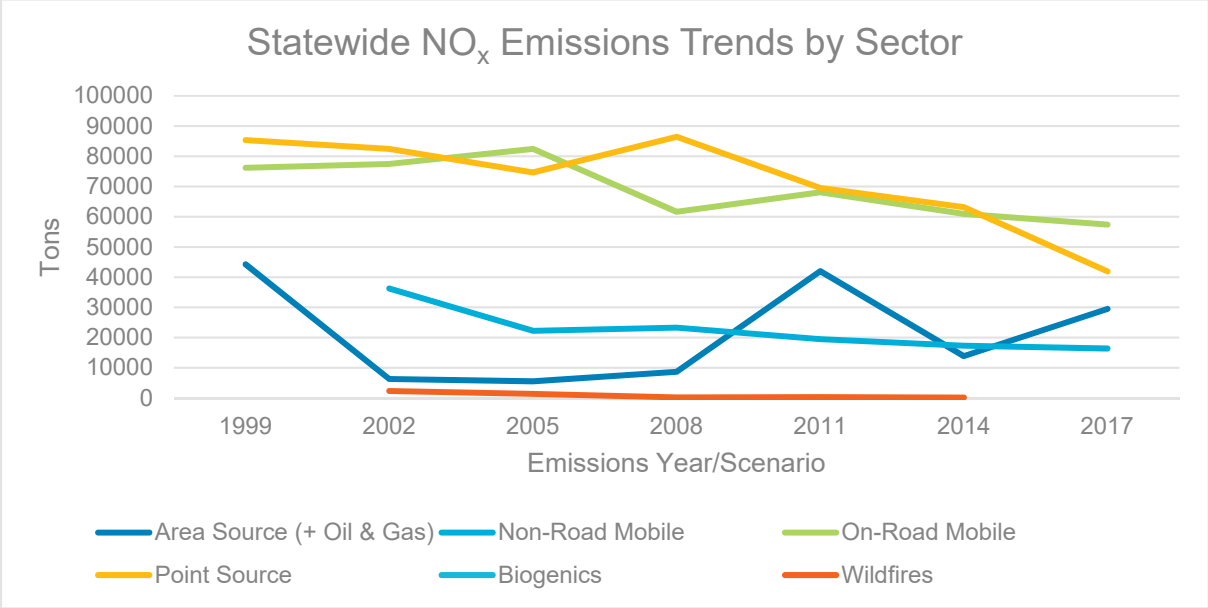

Figure 18: NOx Emissions by Sector

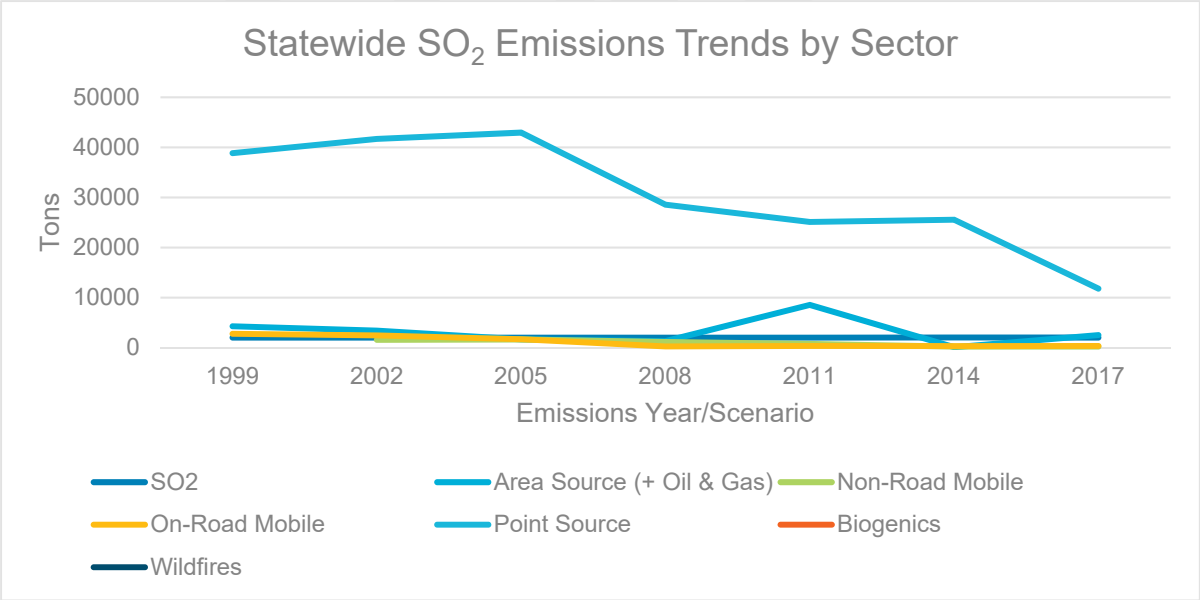

Figure 19: SO2 Emissions by Sector

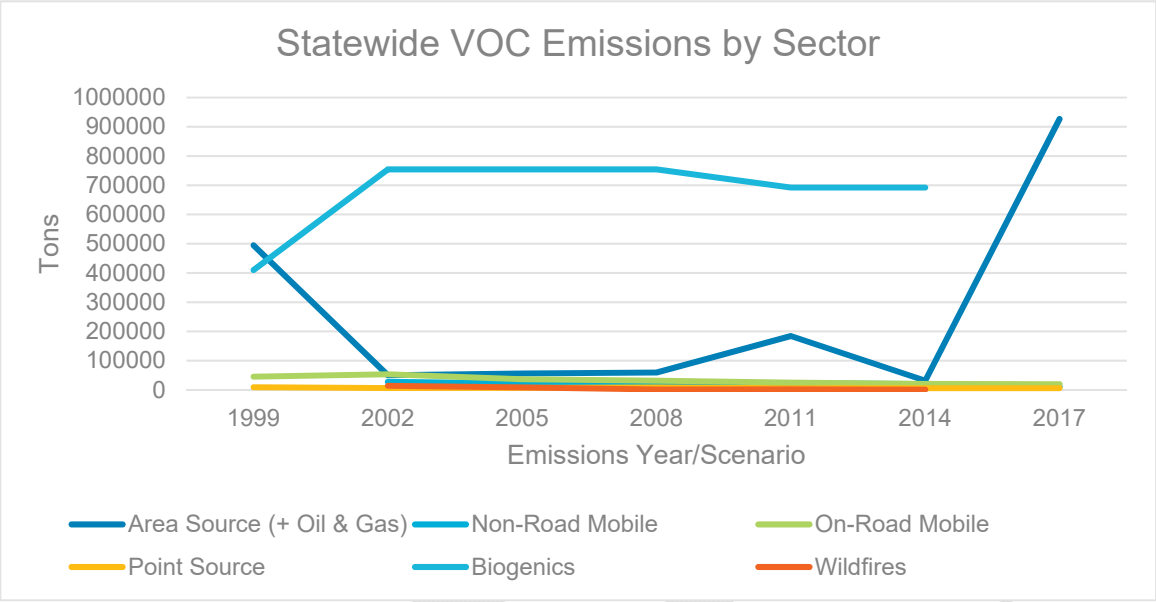

Figure 20: VOC Emissions by Sector

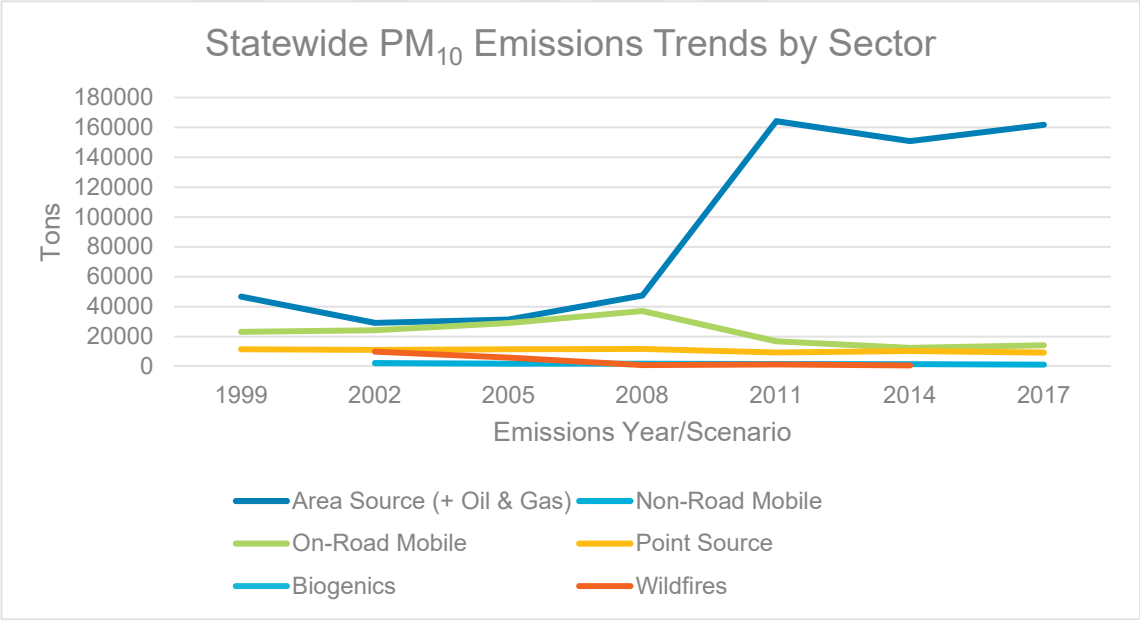

Figure 21: PM_{10} Emissions by Sector

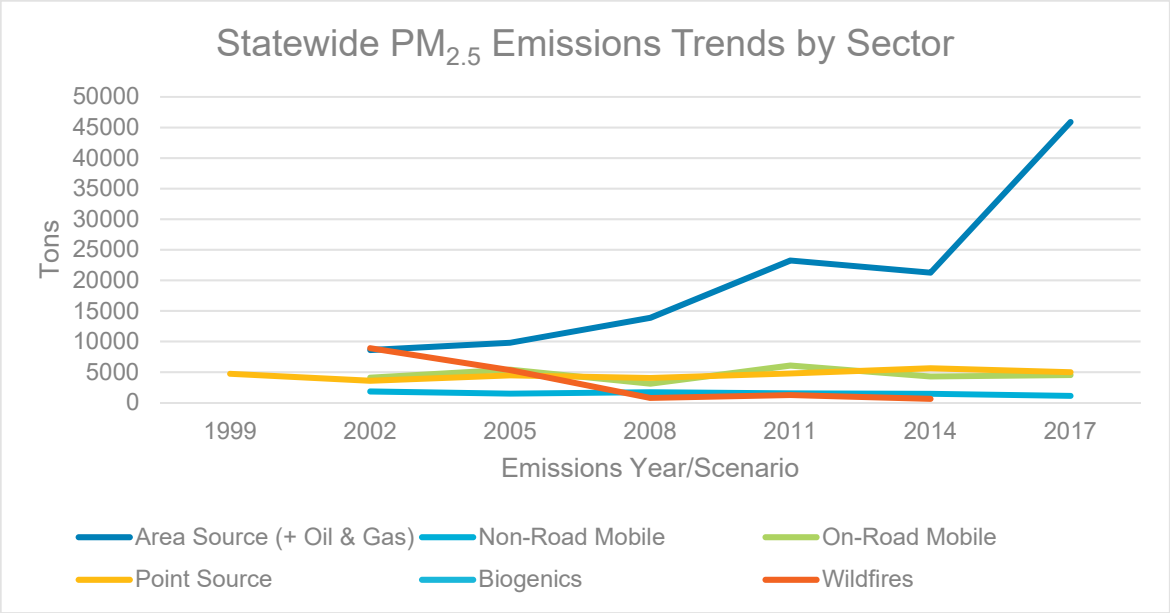

Figure 22: $PM_{2.5}$ Emissions by Sector

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.

[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

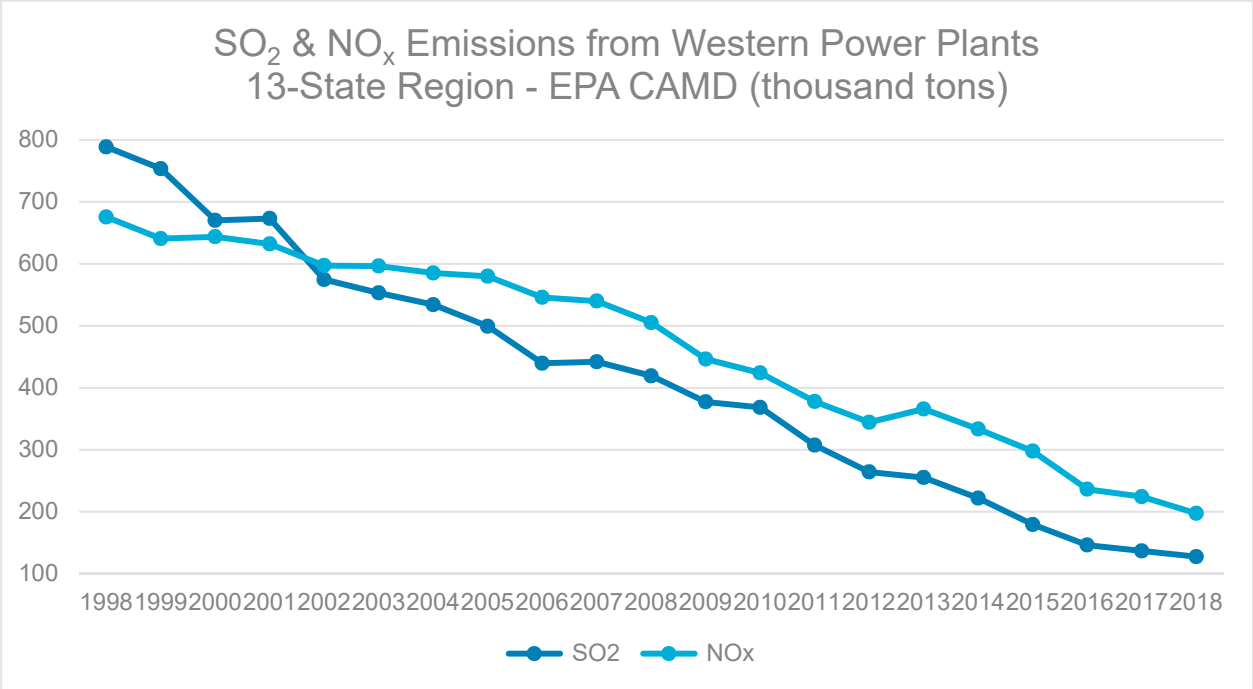

Figure 23: SO_2 and NO_x Emissions Trends for Western Power Plants[1]

The table 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.).

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

State	Facility Name	Unit ID	Operating Year	Retirement Year	Notes
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
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

State	Facility Name	Unit ID	Operating Year	Retirement Year	Notes
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		
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		

State	Facility Name	Unit ID	Operating Year	Retirement Year	Notes
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] The figure below shows the portion of EGU emissions represented by remaining fossil units and retiring coal units. The table below contains data compiled by WESTAR-WRAP showing the changes in emissions from 1996-2018 and percent change throughout the GCVTC states.

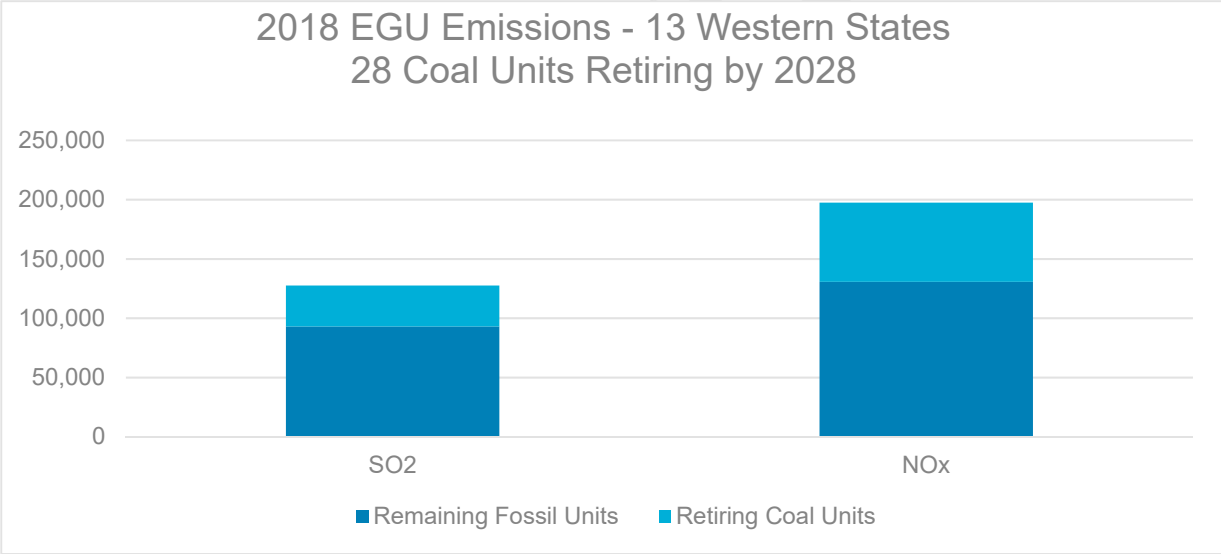

Figure 24: Remaining and Retiring EGU Emissions Apportionment

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

[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

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%ile for the 15-year period from 2000 to 2014. The daily fraction of species extinction values greater than the 95th%ile 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

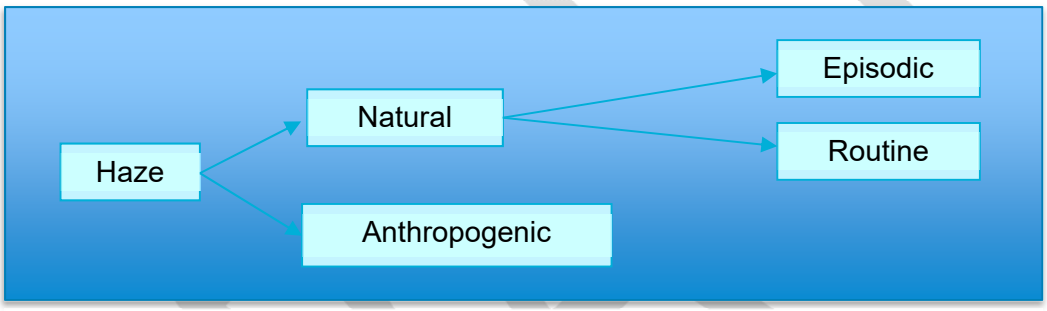

Figure 25: Light extinction for Utah Class I Areas: natural and anthropogenic sources

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) and anthropogenic, natural conditions are calculated as the average of the daily natural

[98] Figure 17 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)

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:

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

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.

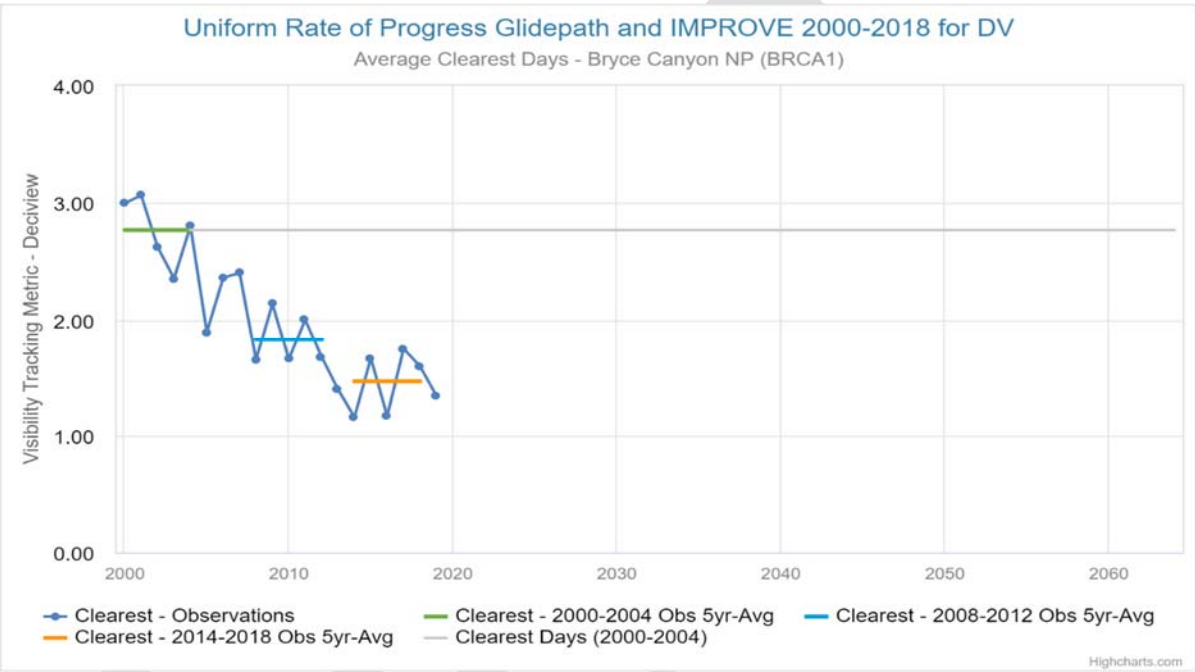

Figure 26: URP Glidepath for Clearest Days, Bryce Canyon NP

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."

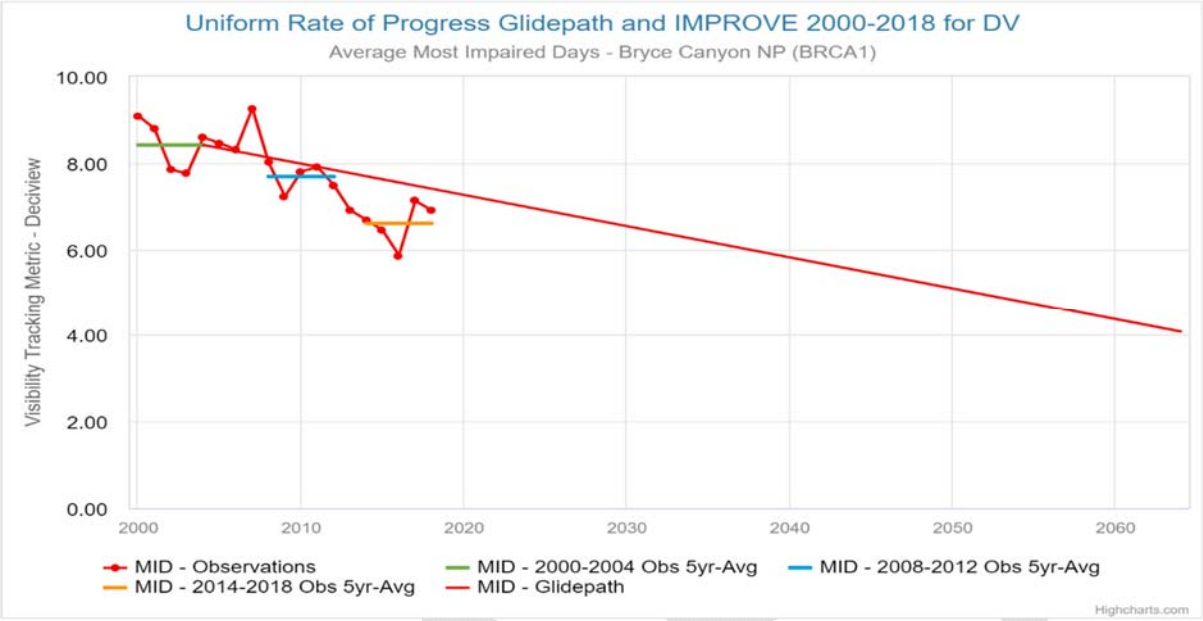

Figure 27: URP Glidepath for most impaired days, Bryce Canyon NP

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]

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

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] Tables 4 and 5 describe the IMPROVE site information for Utah's CIAs

Class I Area Name	Representative IMPROVE Site	Site ID
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.

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

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

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

Site ID	Class I Area Name(s)	Clearest Days (dv)	Most Impaired Days (dv)
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. The following table 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]

The following table 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]

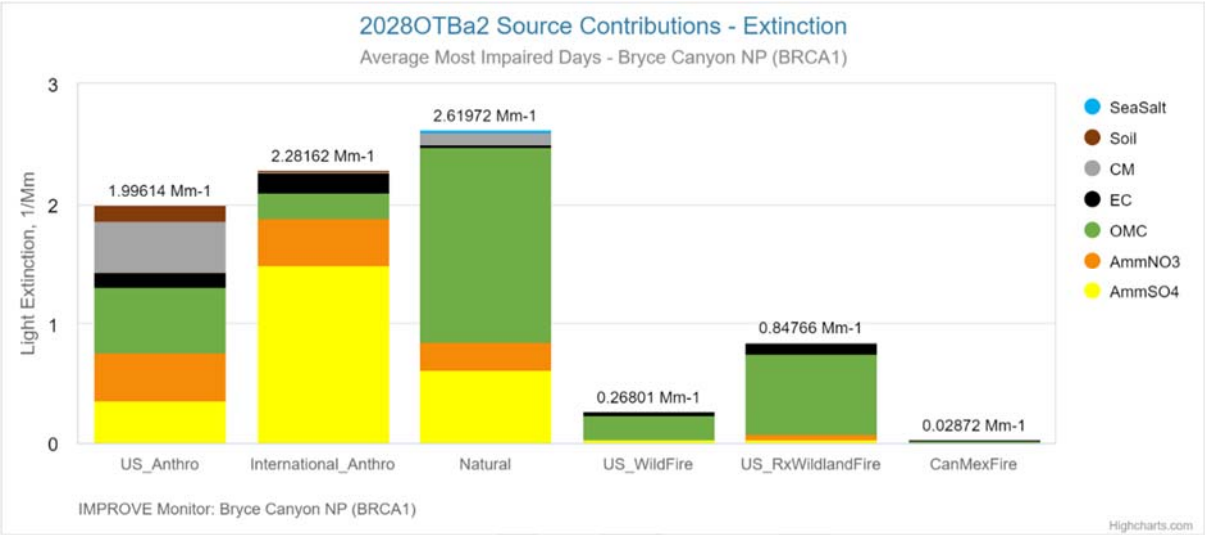

Figure 29: Projected Source Contributions to Light Extinction in Bryce Canyon NP

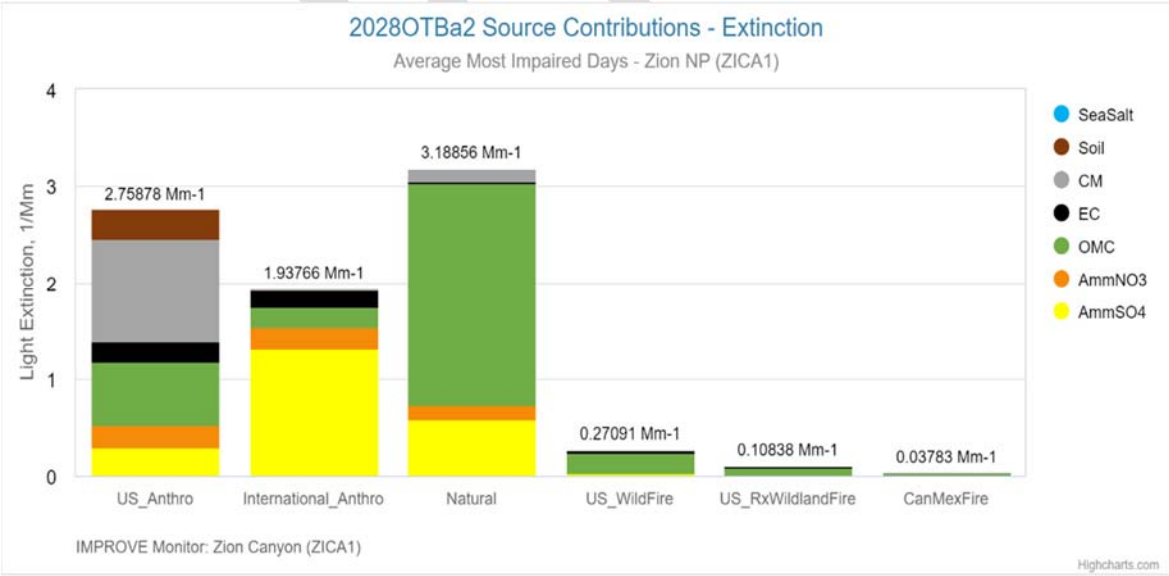

Figure 28: Projected Source Contributions to Light Extinction in Zion NP

[111] "64 Fed. Reg. 35714, 35764."

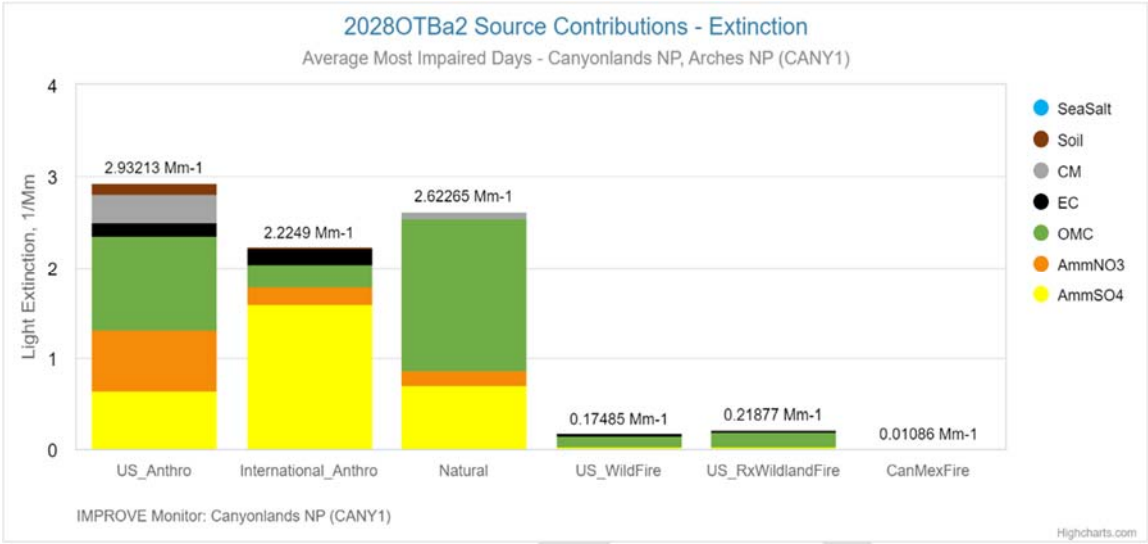

Figure 30: Projected Source Contributions to Light Extinction in Canyonlands and Arches NP

Modeling done by both EPA and WRAP shows that Utah is significantly impacted by international and wildland prescribed fire emissions (as shown by figures 29-31). Further detail on emission source apportionment can be found in Chapter 5: Utah Sources of Visibility Impairment.

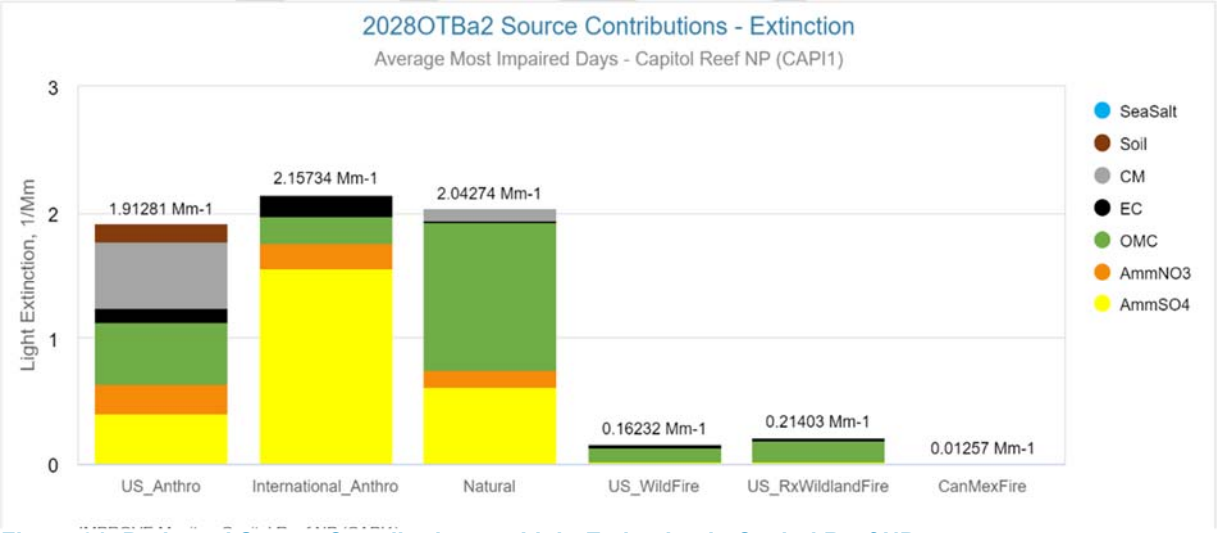

Figure 31: Projected Source Contributions to Light Extinction in Capitol Reef NP

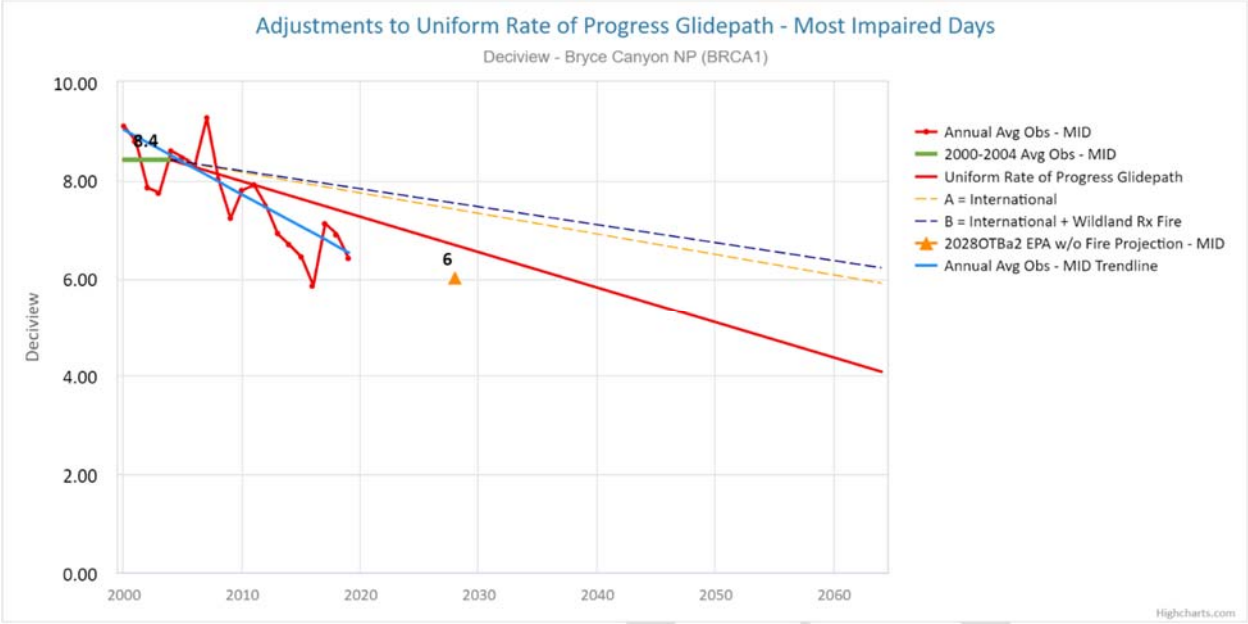

Figure 32: Example URP Glidepath for Bryce Canyon National Park Showing Adjustment Options

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. The following table details the data sources used by WRAP for determining anthropogenic source emissions contributions.

Table 13: Data sources for WRAP emissions sectors[112]

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]

[112] This data sources' table 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[113]:

- 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 Chapter 3 as well as tables 13-20 of this chapter.

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

[113] 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

States Forest Service (USFS) and other land management agencies in Utah closely monitor 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[114] 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. 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. The following table 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

[114] 40 C.F.R. § 51.308(d)(4)(v).

Facility Name	Unit ID	In-Service Year	Retirement Year	Notes	Operator	Unit Type
Intermountain	2SGA	1987	2025	Announced retirement	Intermountain Power Service Corporation	Dry bottom wall-fired boiler
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.[115]

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.

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**

[115] 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.

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 2028 OTB a2 modeling, SO_2 emissions are projected to decline to 14,979 tons per year in 2028.

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

Utah – Statewide NO_x Emissions (TPY)				
Type	**Source Category**	**2014v2 Actual**	**Representative Baseline 2**	**2028 OTB a2**
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

Utah – Statewide NO_x Emissions (TPY)				
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 2028 OTB a2 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
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

Utah - Statewide VOC Emissions (TPY)				
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 2028 OTB a2 projections.

Table 18: Utah PM2.5 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 2028 OTB a2 modeling.

Table 19: Utah PM2.5 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 $\mu g/m^3$. 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 2028 OTB a2 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 NH3 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[116]

6.A LTS Requirements [117]

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.
- 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.

6.A.1 States reasonably anticipated to contribute to visibility impairment in the Utah CIAs[118]

[116] 40 CFR 51.308(f)(2)
[117] 40 CFR 51.308(d)(3) and (f)(2)

[118] 40 CFR 51.308 (f)(2)(ii)

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%.

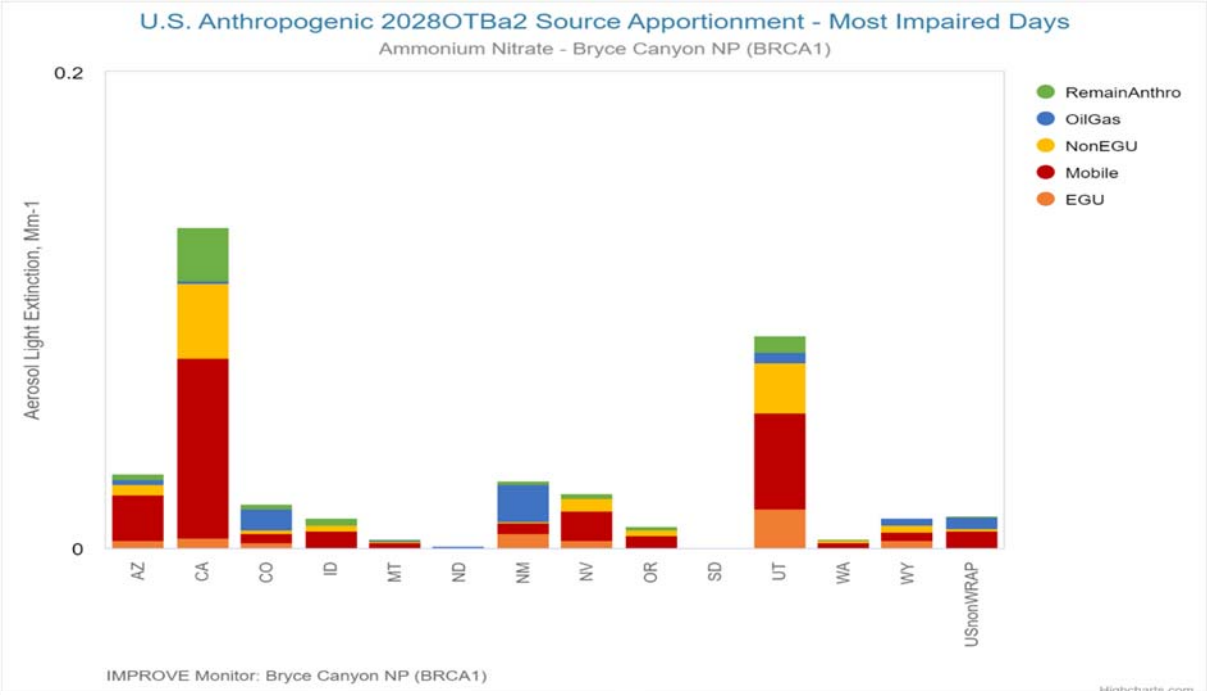

Figure 33: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Bryce Canyon National Park

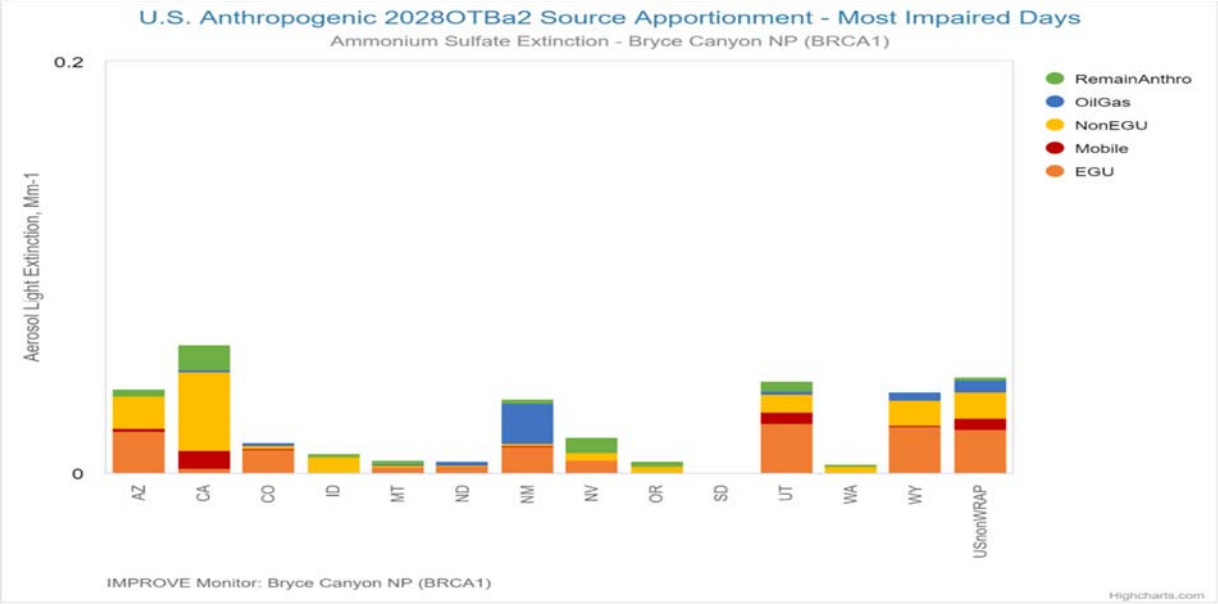

Figure 34: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Bryce Canyon National Park

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%).

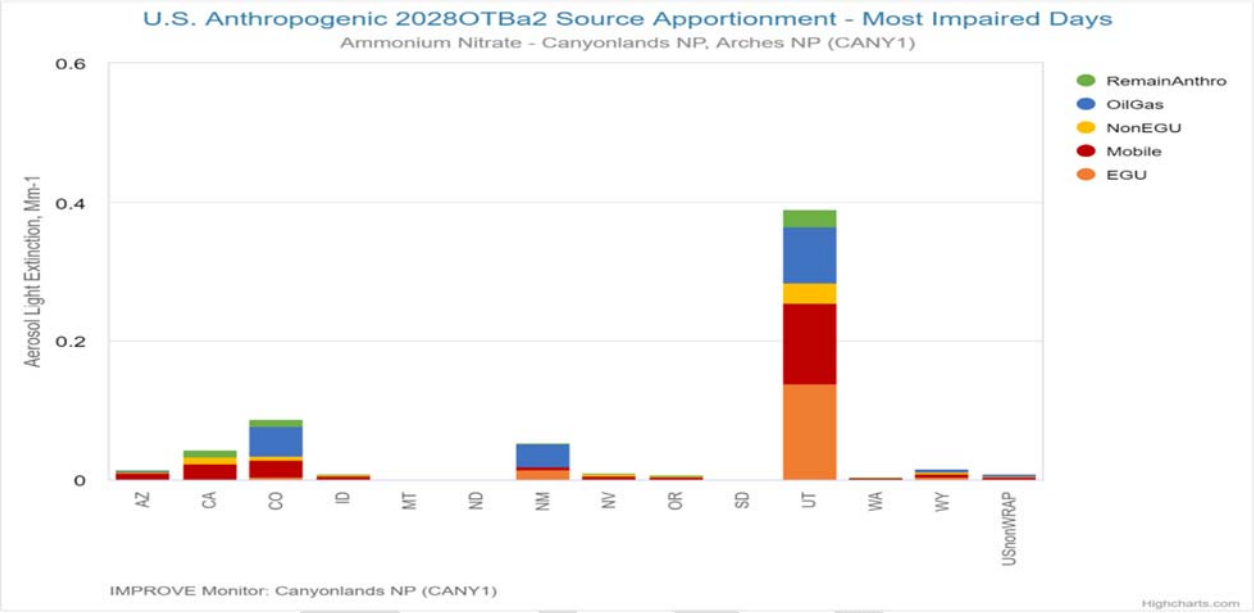

Figure 35: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Canyonlands and Arches National Park

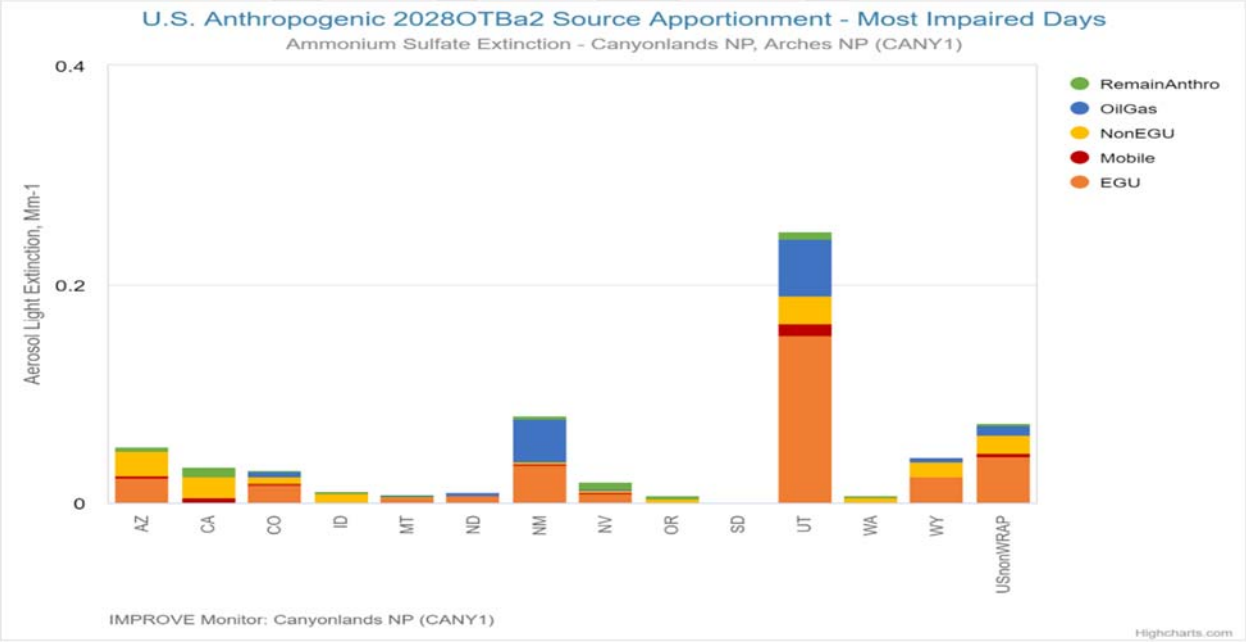

Figure 36: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Canyonlands and Arches National Park

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%).

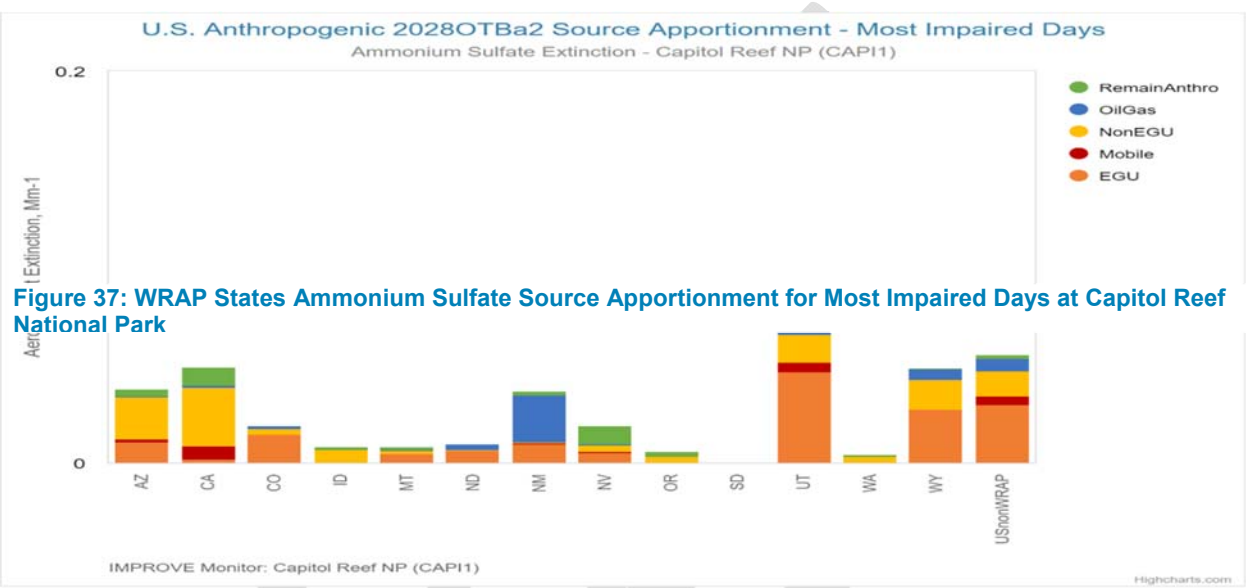

Figure 37: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Capitol Reef National Park

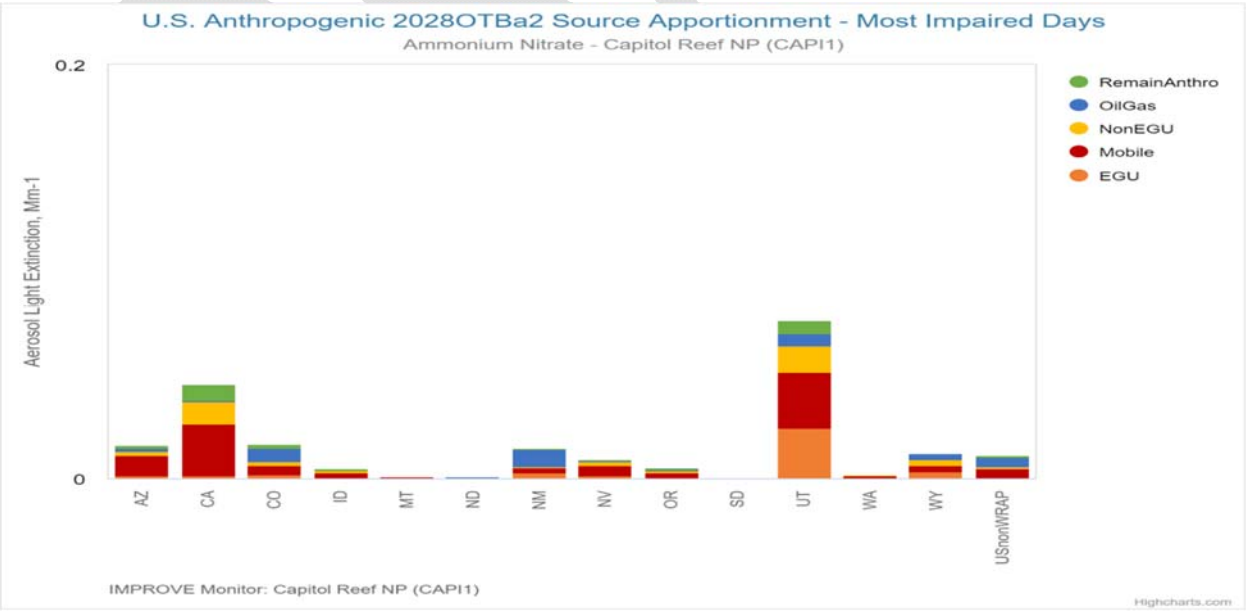

Figure 38: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Capitol Reef National Park

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%).

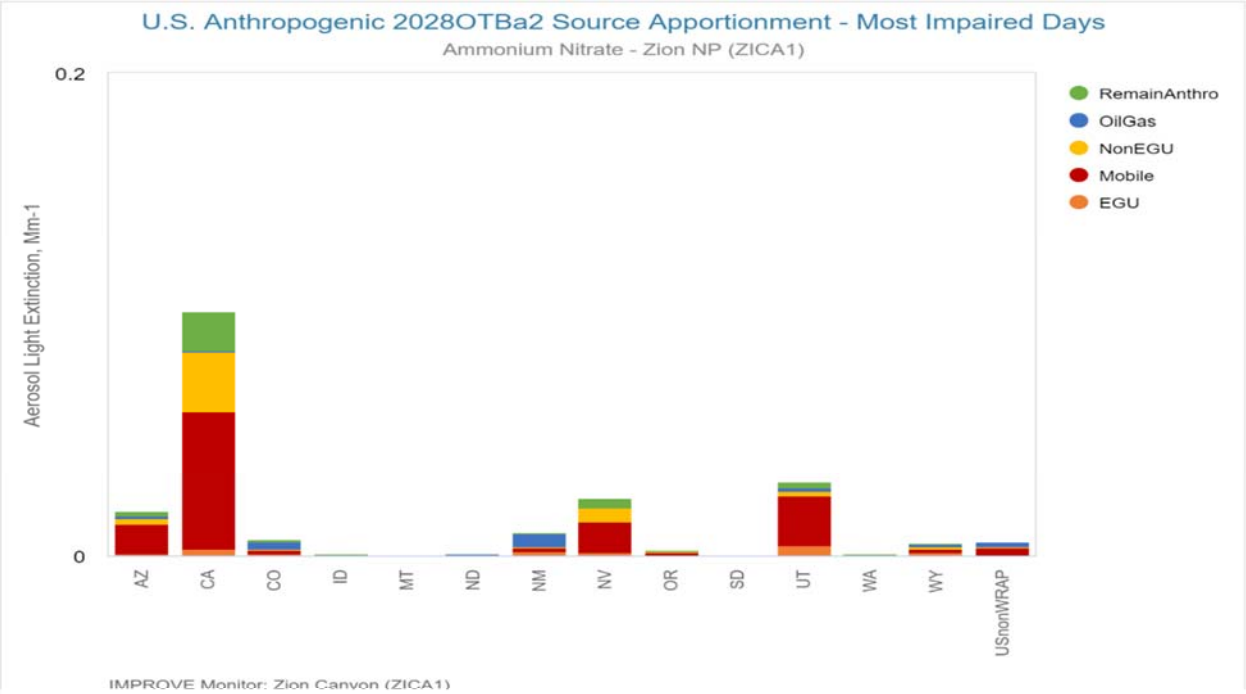

Figure 39: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Zion National Park

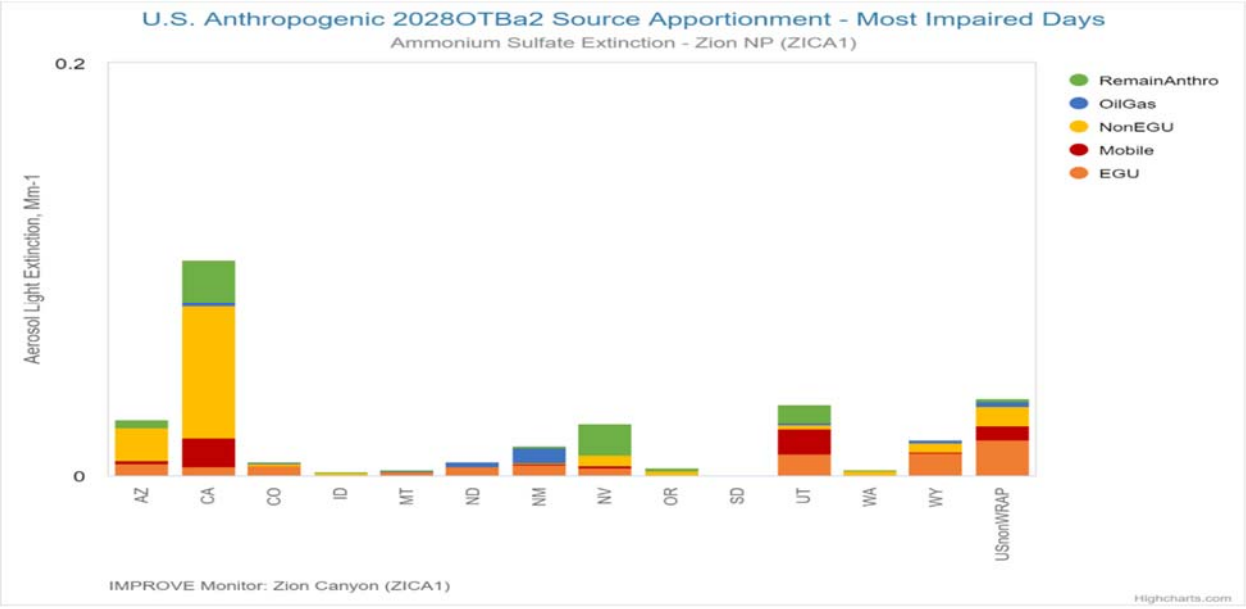

Figure 40: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Zion National Park

6.A.2 Utah sources identified by downwind states that are reasonably anticipated to impact CIAs[119]

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 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%

[119] 40 CFR 51.308 (f)(2)(ii)(A)

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
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%
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%

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
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%
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%

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
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%
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%

State	Site	EGU	Mobile	Non-EGU	Oil & Gas	Remaining Anthro	Utah Total
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%
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 Chapter 4: Utah Visibility Analysis to view Utah's URP glidepaths and each CIAs' 2028 projections.

6.A.4 Identify Anthropogenic Sources

Please refer to sections 5.C and 5.E of Chapter 5: Utah Sources of Visibility Impairment for a detailed emissions inventory by sector. Please refer to sections 7.A and 7.A.1 of Chapter 7: Emissions Control Analysis 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

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:[120]

- 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[121] 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.

[120] 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

[121] 40 CFR 51.302

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 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 NO2 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 99th%ile 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. Part H. 23.[122]

6.A.9 Source retirement and replacement schedules

The table below 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

[122] See Appendix A of this draft SIP.

31, 2027, to 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.[123] 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

[123] 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. Please note that a 22.5-ton reduction in NOx resulting from the controls determination for US Magnesium's Riley Boiler located in section 8.D.6 was not included in these modeled projections. The 2028OTBa2 visibility projection also includes emissions from the now-closed Kennecott Power Plant, which was projected to have 1,152 tons of NOx, 2,152 tons of SO2, and 135 tons of PM10 emissions in 2028. 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.

Table 26 below 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 26: 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.

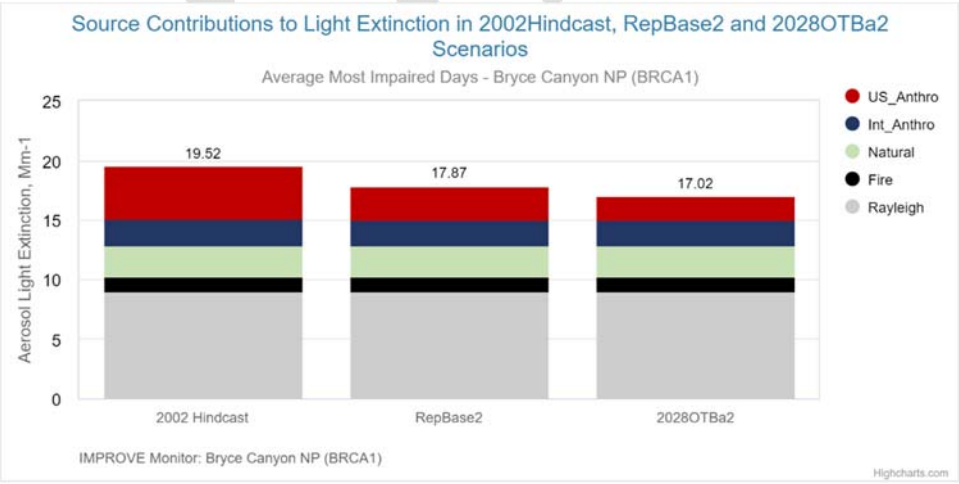

Figure 41: Modeled Visibility Progress for MID at Bryce Canyon National Park

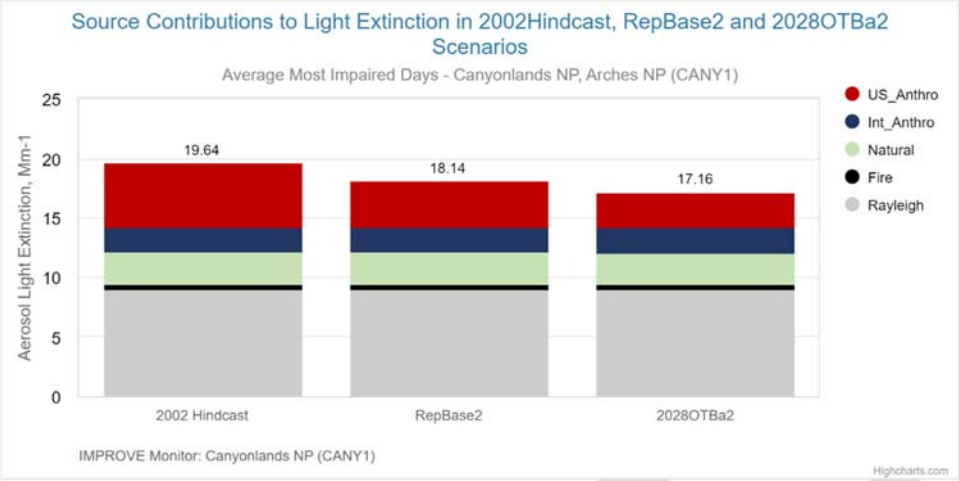

Figure 42: Modeled Visibility Progress for MID at Canyonlands and Arches National Park

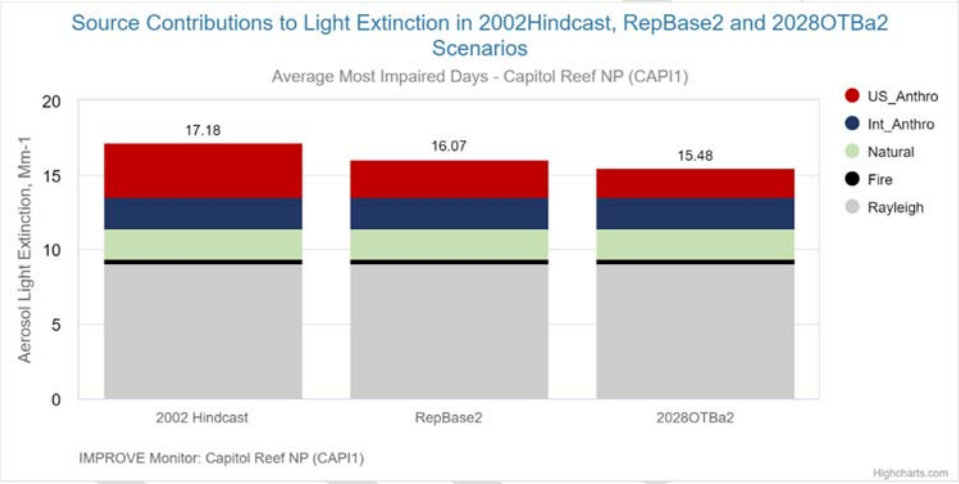

Figure 43: Modeled Visibility Progress for MID at Capitol Reef National Park

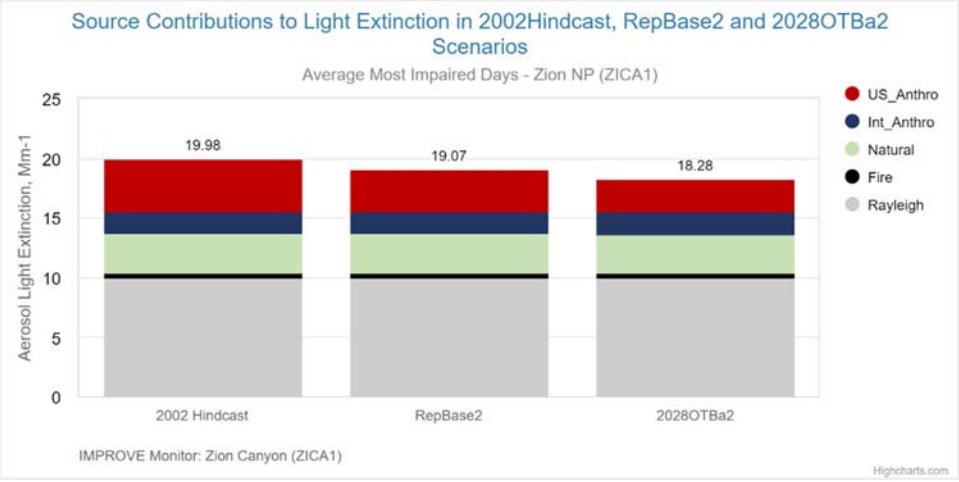

Figure 44: Modeled Visibility Progress for MID at Zion National Park

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.

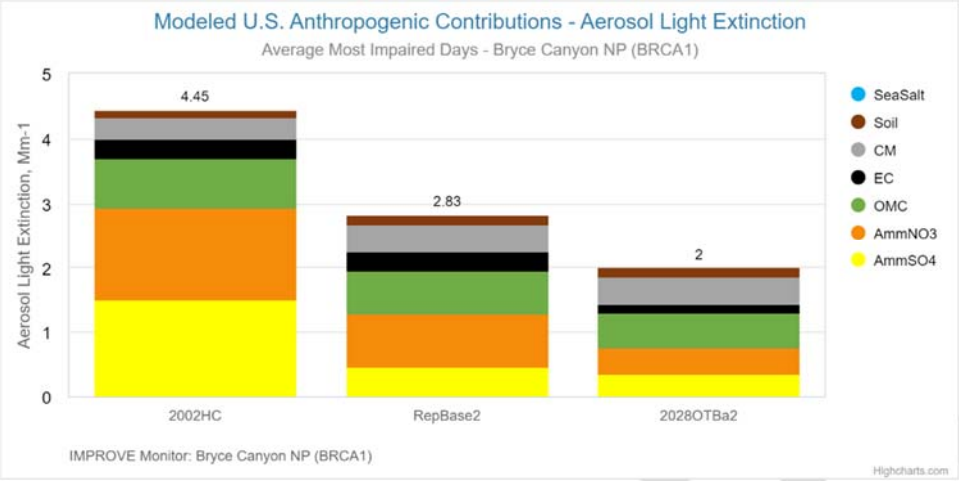

Figure 45: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Bryce Canyon National Park

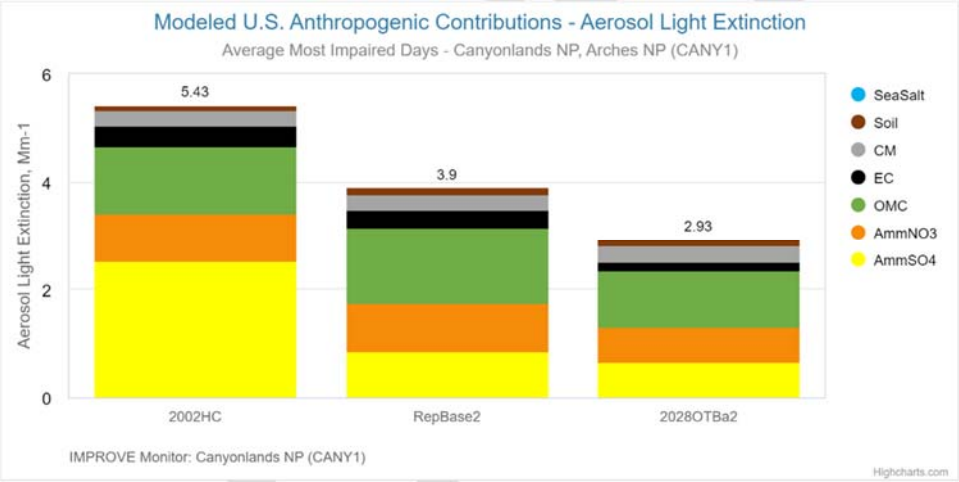

Figure 46: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Canyonlands and Arches National Park

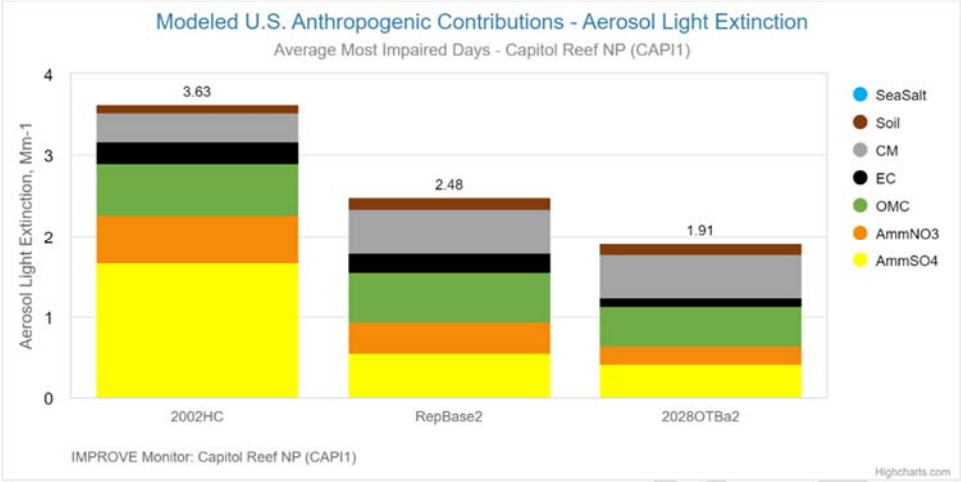

Figure 47: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Capitol Reef National Park

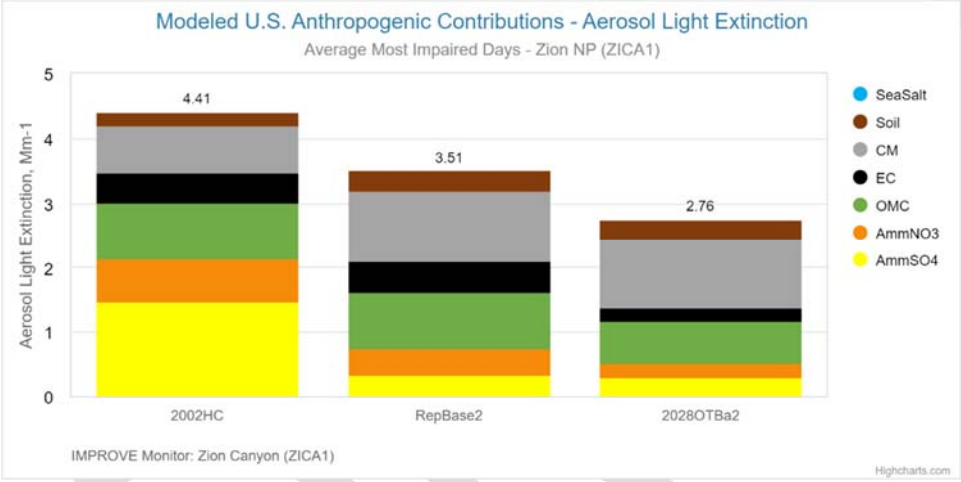

Figure 48: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Zion National Park

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. Part H. 21., 22., and 23, which are made enforceable through EPA approval and incorporation into the Utah Air Quality Rules. The proposed part H language can be found in Appendix A.

Chapter 7: Emission Control Analysis[124]

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. The figure below shows that, on most impaired days, US anthropogenic, international, and biogenic pollution are the most significant sources of light extinction. Figures 50 and 51 further apportions 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.

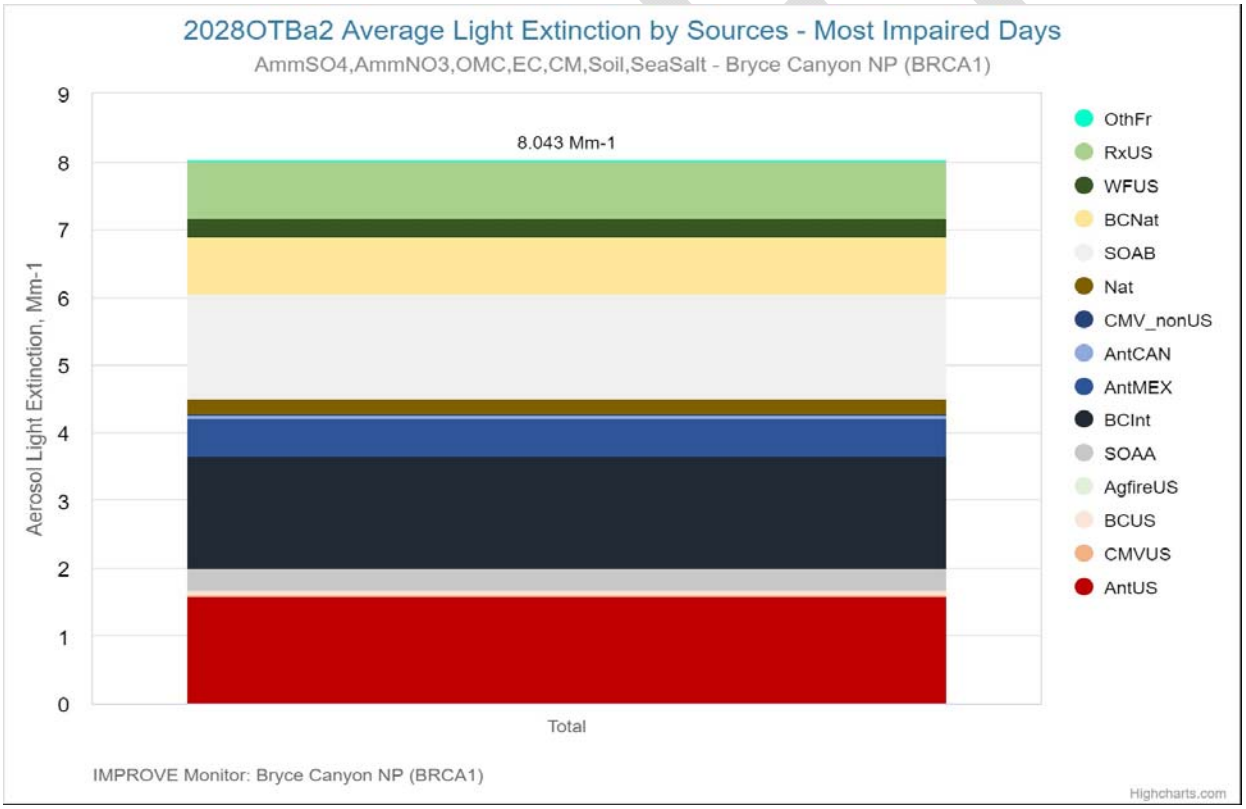

Figure 49: Average Light Extinction by Sources in Bryce Canyon National Park

[124] 40 CFR 51.308(f)(2)(i)

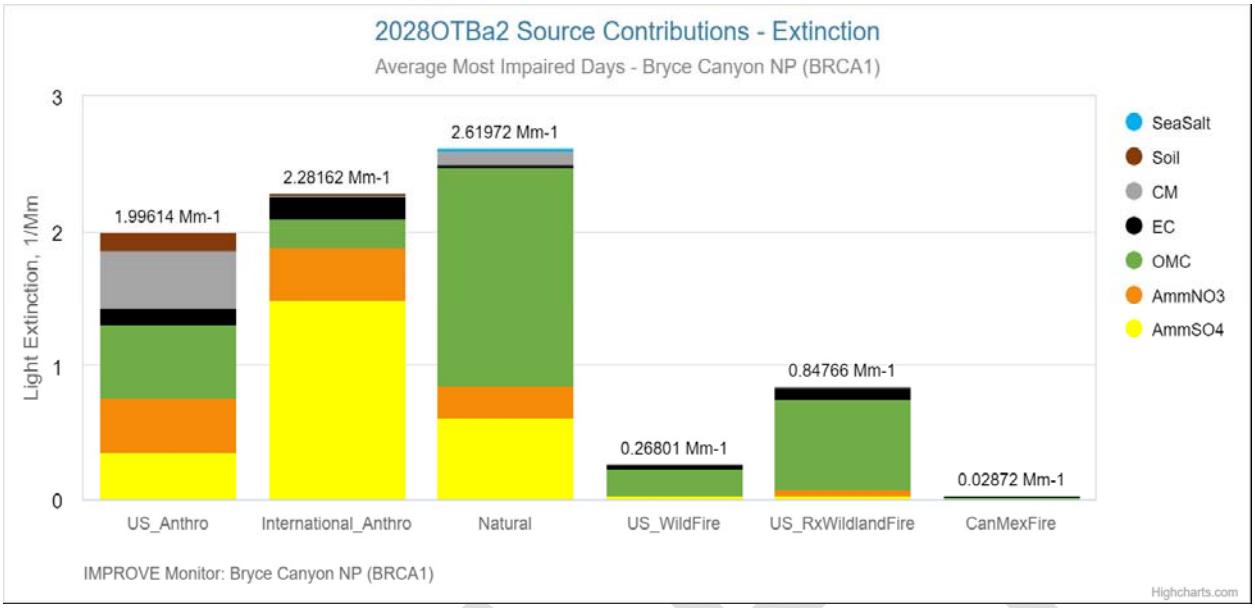

Figure 50: Source Contributions on Average Most Impaired Days in Bryce Canyon National Park

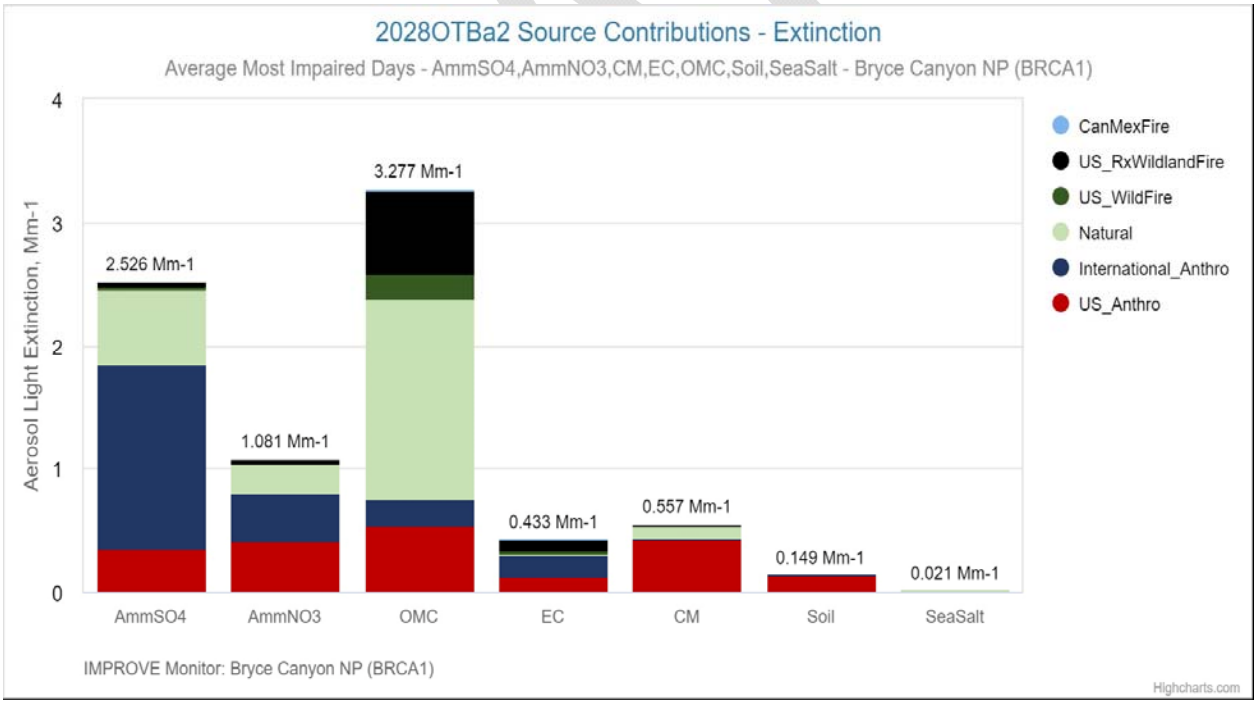

Figure 51: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Bryce Canyon National Park

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).

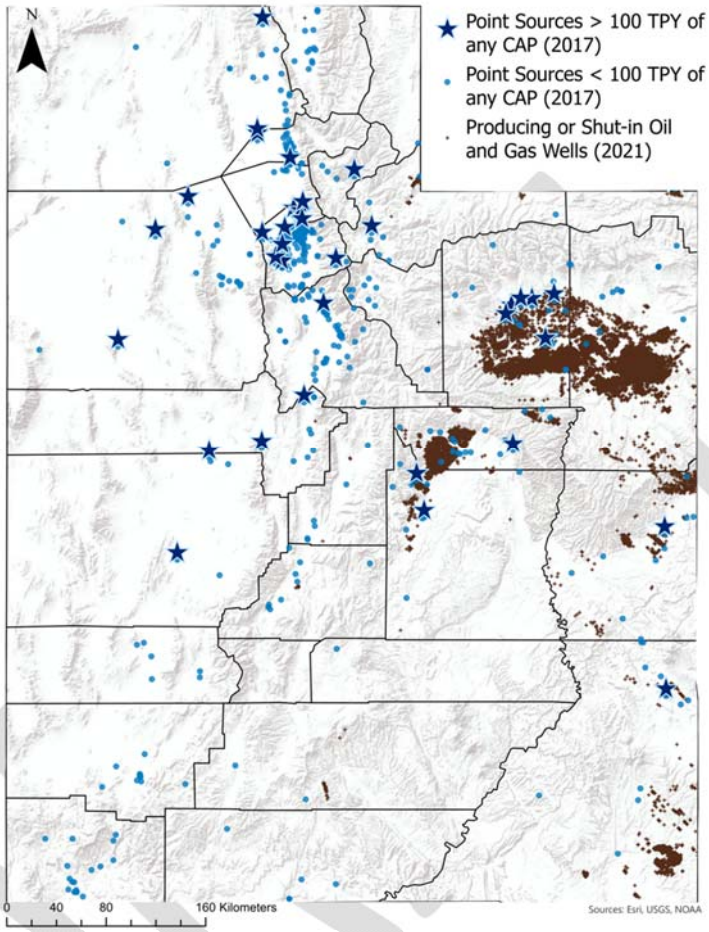

Figure 52: Map of Utah Regulated Sources with Emissions >100 TPY

7.A.1 Q/d Analysis

The RHR[125] 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 included in the analysis. WRAP's analysis suggested using a Q/d value of 10 as the threshold

[125] 40 C.F.R. § 51.308(f)(2).

for sources with the most potential to impact CIAs. However, UDAQ used a more conservative threshold of six.[126]

Table 27: 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	Bryce Canyon	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	Canyonlands	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 2018 emissions, projected 2028 emissions, and planned closure, allowed them to be exempt from a 4-factor analysis									

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,

[126] See table 27

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

Regarding the CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant's exclusion from consideration. In 2009 the plant received a permit modification to lower the SO2 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 SO2. Unfortunately, in 2010 the plant requested a new modification and mistakenly restored the original 1,593 tons of SO2 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. Rather, the actual emissions from the facility are more in line with the proper 2009 PTE of 111 tons.

During the original Q/d analysis, 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. However, based upon updated 2018 emissions for the plant, the combined Q/d values dropped to 3.30 for Arches and 5.03 for Canyonlands. For this reason, this source was ultimately not required to provide a four-factor analysis. In response to FLM feedback, however, UDAQ has requested additional information from Paradox Resources and will include this information in the final draft of this SIP.

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 percent 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 SO2 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 Kennecott Mine and Copperton Concentrator recently underwent BACT analysis as part of the Salt Lake $PM_{2.5}$ SIP. As a result, there are no additional controls that can be applied at this time[127]. The predominant visibility impairing pollutant from this facility is NO_x, the vast majority of which comes from mine haul trucks and other non-road equipment as shown in Table 28 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.[128] Though Section IX.H of the Utah SIP does include in-use requirements capping total mileage per calendar day for this equipment in relation to both PM_{10} and $PM_{2.5}$ emissions, UDAQ does not anticipate additional emissions reductions from this equipment until such time as the fleet turns over to more recent Tier 4 standards.[129]

Table 28: 2017 Kennecott Utah Copper LLC – Mine & Concentrator Emissions and Revised Q/d

Source/Distance/Q/d	PM10	SO2	NOX	PM10+SO2+ NOX
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 reflecting this change was updated on February 4, 2020[130]. The vast majority of emissions from that facility were associated with the boilers and 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). The

[127] Current requirements relating to the $PM_{2.5}$ SIP for this facility can be found at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2020-014982.pdf
[128] *See* 42 U.S.C. § 7543(e).
[129] See pages 24 and 131 of https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2020-014982.pdf.

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

emissions are small enough that this source is below the Q/d threshold for the four-factor analysis.

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. Tables 29 and 30 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 31 and 32 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.

Table 29: 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)	Included in 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)	Included in 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	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)	Included in 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	
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	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	
CAPI1	5	Ash Grove Cement Company-Leamington Cement Plant	UT	845.5	159,501.2	5.3	24,633.4 (2.7%)	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)	Included in Four-Factor Analysis? (Y/N)	Notes
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
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

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)	Included in Four-Factor Analysis? (Y/N)	Notes
ZICA1	6	Pg&E Topock Compressor Station	CA	968.8	300,092.2	3.2	7,620.0 (3.1%)	NA	NA	
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	
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 30: 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)	Included in 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	
BRCA1	2	PacifiCorp-Hunter Power Plant	UT	3,498.2	198,466.7	17.6	22,430.8 (11.2%)	YES	YES	
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	
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

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)	Included in Four-Factor Analysis? (Y/N)	Notes
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	
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
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	
CANY1	8	CHEMICAL LIME NELSON PLANT	AZ	2,040.6	448,519.3	4.6	13,409.0 (3.3%)	NA	NA	
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	PNM has announced plant closure in 2022

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)	Included in Four-Factor Analysis? (Y/N)	Notes
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	
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	
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	Federally enforceable closure date of December, 31, 2028
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	
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	

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)	Included in 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	
ZICA1	8	Republic Services Sunrise	NV	209.5	201,737.4	1.0	4,025.8 (2.6%)	NA	NA	
ZICA1	9	TUCSON ELECTRIC POWER CO - SPRINGERVILLE	AZ	6,991.9	480,561.1	14.5	3,447.7 (2.2%)	NA	NA	
ZICA1	10	PacifiCorp-Huntington Power Plant	UT	2,449.0	300,744.4	8.1	3,032.3 (1.9%)	YES	YES	

Table 31: 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_NO_3 (% 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
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

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
											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 32: 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

The Uinta Basin (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[131].

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 NOx 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 NOx emissions that contribute to nitrate formation and CIA impacts.

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 PM2.5 SIP BACM review and resulting controls). For example, Utah restricts residential wood burning on so-called mandatory action days when conditions are ripe

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

for secondary formation of particulates. Utah has also adopted an ultra-low NOx water heater rule that applies statewide and, when fully implemented, will result in a 75% reduction in NOx emissions from residential and commercial water heating-related natural gas stationary source fuel combustion. Additional Utah area source rules to reduce NOx and/or PM emissions include those governing hydronic heaters, fugitive dust, and pilot lights.

7.B Four-Factor Analyses for Utah Sources[132]

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. 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[133]

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 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[134]

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

[132] 40 CFR 51.308(f)(2)(i)
[133] *See* 40 C.F.R. § 51.308(f)(2)(i).
[134] 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

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 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[135]

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.

[135] 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

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 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 33: 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 34: 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

Facility Name	Unit ID	Owner	NO_x Control(s)
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[136] 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

[136] 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

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.[137]

7.C.1 Ash Grove Cement Company- Leamington Cement Plant Four-Factor Analysis Summary and Evaluation[138]

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.

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 35: Ash Grove Leamington Cement Plant Current Potential to Emit

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

[137] 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.
[138] Ash Grove's full four-factor analysis submittal can be found in appendix C.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008930.pdf

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[139]

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[140]

AGC provided the actual SO2 emissions rates for the Leamington Plant's main kiln which are lower than their PTE. Lowering SO2 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. NOx/ton clinker on a 30-day rolling average basis, and the plant typically operates in the 2.5-2.6 lb. NOx/ton clinker range. The system uses an Aqua NH3 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 NH3 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.

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[141]

[139] UDAQs full evaluation of Ash Grove's four-factor analysis submittal can be found in appendix C.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009636.pdf
[140] Ash Grove's full evaluation response can be found in appendix C.3 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011724.pdf
[141] Graymont's full four-factor analysis submittal for the Cricket Mountain Plant can be found in appendix D.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008924.pdf

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 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 36: 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[142]

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 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.

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

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 37: Estimated Direct Annual Costs (doubled) Graymont

Kiln	Capital Costs ($)	Direct Annual Costs ($)	Total Annual Costs ($)	NO_x Removed (tons)	cost-effectiveness ($/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[143]

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

[143] Graymont's full evaluation response can be found in appendix D.3 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011722.pdf

each Cricket Mountain kiln combined with the Low NO_x baseline concentration already achieved through the use of Low NO_x Burners (LNB)[144].

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 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).

[144] 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%.

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[145]

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 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.

[145] PacifiCorp's full four-factor analysis submittal for the Hunter and Huntington power plants can be found in appendix E.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008926.pdf

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 38: 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[146]

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 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

[146] UDAQ's full four-factor analysis evaluation for the Hunter and Huntington power plants can be found in appendix E.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008926.pdf

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 39: 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[147]

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;

• 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 38 to calculate boiler heat input; and lastly;

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

• Utilize the actual 2015-2019 average annual capacity factors in Table 40 instead of the rates included in Table 39, 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 NOx control efficiency versus the studies' original use of a 7% interest rate and anticipated SNCR-controlled permit limit emission rates.

Table 40: 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 0.280 4,359	 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**

Table 41: 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 NOx 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

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 12 lb/mmbtu over various averaging periods) that correspond to these controls as included in the approval orders for both plants. Because Utah participated in the Section 309 compliance pathway for SO_2 in its round one SIP, SO_2 emissions limits were not included among the Section IX.H controls for regional haze. However, because 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.H23, Source Specific Emission Limitations: Regional Haze Requirements, Reasonable Progress Controls, to ensure federal enforceability in the regional haze context.

NOx

Upon consulting with EPA staff and the control cost manual, 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.[148] 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.

For SNCR and SCR, UDAQ concurs with PacifiCorp's remaining 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

[148] Source: https://pscdocs.utah.gov/electric/20docs/2003504/3168662003504ro12-30-2020.pdf

each plant's 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 a different baseline emissions scenario (i.e., the PAL) than that used for SNCR and SCR (2015-2019 actuals). 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 SCR and SNCR 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 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 the table below.

Table 42: 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

Due to the relatively high $/ton estimates for SNCR, that control was deemed not to be cost-effective. UDAQ's remaining cost-effectiveness evaluation centers around the potential application of SCR at one or more units at the Hunter and Huntington power plants. In particular, the relatively lower estimated $/ton for SCR for Hunter 3 merits further evaluation of whether this control could be cost-effective.

As noted above, PacifiCorp's cost-effectiveness estimates were calculated using a baseline of recent actual emissions 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.[149]

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 emissions 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.*[150]

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 emissions 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.*

[149] *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.

[150] *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.

> *. . . 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.*[151]

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

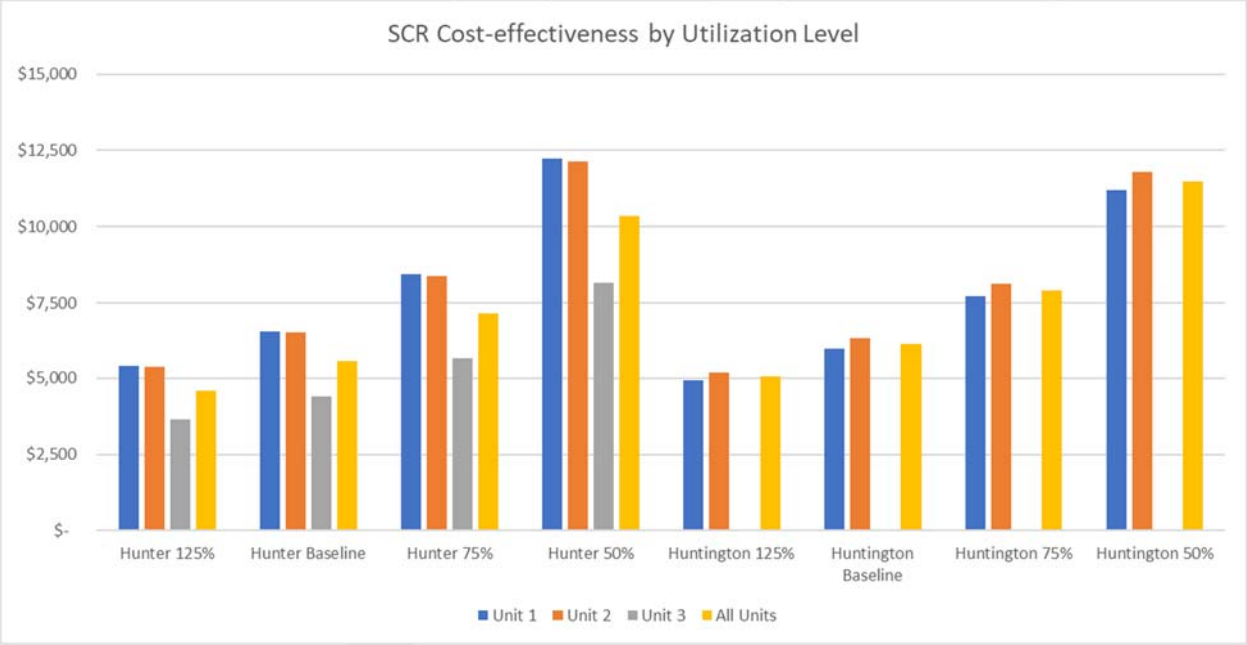

Figure 53: SCR Cost-effectiveness by utilization level at Hunter and Huntington Power Plants

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).

[151] *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.

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.[152] 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 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.[153] 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. Arguably, PacifiCorp's cost-effectiveness estimates would apply should future emissions (and thus, utilization) conform to these 2028 OTB estimates. However, 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. For these reasons, recent actual emissions from fossil-fueled EGUs are down from the levels of previous decades, and there is great uncertainty regarding near- and medium-term operation of these units. This trend is reflected in the utilization[154] of the Hunter and Huntington power plants as shown in figures 54 and 55 below.

[152] *See* http://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf.
[153] 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.
[154] 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).

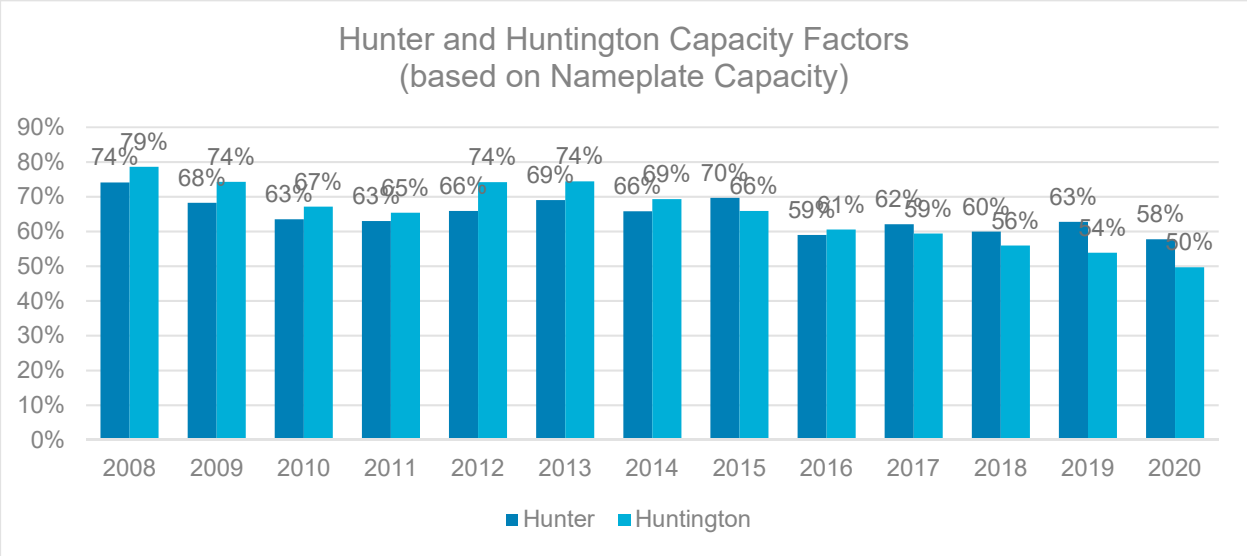

Figure 54: Hunter and Huntington Capacity Factors

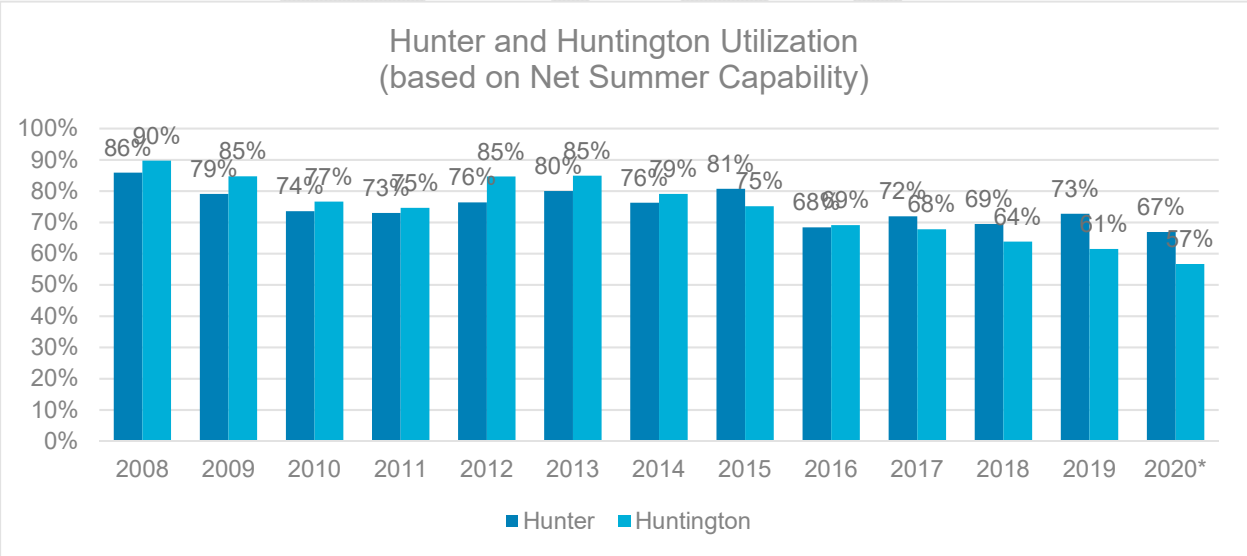

Figure 55: Hunter and Huntington Utilization (based on Net Summer Capability)

Given this uncertainty and the wide variability in cost-effectiveness estimates at various utilization levels, UDAQ finds installation of SCR not to be cost-effective at any of the five units at Hunter and Huntington at this time. However, because WRAP's photochemical modeling to demonstrate reasonable progress used projections based, in part, upon recent actual EGU

Figure 56: Example of projected RPGs for Canyonlands and Arches CIAs

emissions and because SCR appears to be more cost-effective at higher than recent utilization/emissions levels, UDAQ finds it compelling to incorporate enforceable mass-based emission limits at both plants to ensure that the EGU nitrate contribution to light extinction at Utah (and other states) CIAs does not exceed modeled or recent actual emissions levels.[155] Such mass-based emission limits would ensure that Utah is making reasonable progress as demonstrated by the WRAP modeling, while eliminating the possibility of backsliding on past emissions reductions. Specifically, mass-based emissions limits based on WRAP's 2028 OTB projections are explicitly accounted for in Utah's projected 2028 RPGs, such as the example shown for Canyonlands in Figure 56.

Establishing enforceable mass-based limits also keeps the plants from operating at higher utilization levels at which SCR controls might become cost-effective and, therefore, reasonable. 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.

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

7.C.4 Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility Four-Factor Analysis Summary and Evaluation[156]

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 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

[156] Sunnyside's full four-factor analysis can be found in appendix F.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008928.pdf

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 43: 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[157]

UDAQ noted several potential errors in Sunnyside's analysis:

[157] UDAQ's full evaluation of Sunnyside's four-factor analysis submittal can be found in appendix F.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009630.pdf

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.
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[158]

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.[159] 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 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.

[158] Sunnyside's full evaluation response can be found in appendix F.3 or at: https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2021-017202.pdf
[159] Based on fly ash characterization results conducted at Sunnyside Cogeneration Associates.

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[160]

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

[160] US Magnesium's full four-factor analysis submittal for the Rowley Plant can be found in appendix G.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2020-014024.pdf

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 44: Current Potential to Emit

Pollutant	Potential to Emit
SO_2	24.10
NO_x	1,260.99

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[161]

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 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[162]

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

[161] UDAQ's full evaluation of US Magnesium's four-factor analysis submittal can be found in appendix G.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009628.pdf

[162] US Magnesium's full evaluation response can be found in appendix G.3 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011902.pdf

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 45: 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, 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.

7.D UDAQ Four-Factor Analysis Summary

Add 4-factor analysis summary matrix to show that each have been addressed for all sources

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.[163]

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[164] 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[165] 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, 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.

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[163] *See* 42 USC § 7492(g)(1).

[164] 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

[165] 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

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[166] 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[167]

These charts illustrate the Uniform Rate of Progress (URP) Glidepath, as defined by EPA guidance,[168] 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 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 NOx emissions reductions associated with the installation of FGR

[166] 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
[167] 40 C.F.R. § 51.308(f)(3)(i)
[168] 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

controls on the Riley Boiler at U.S. Magnesium's Rowley Plant. However, the resulting reduction in NOx emissions is a small percentage of Utah's total 2028 NOx emissions. The 2028OTBa2 visibility projection also includes emissions from the now-closed Kennecott Power Plant, which was projected to have 1,152 tons of NOx, 2,152 tons of SO_2, and 135 tons of PM2.5 emissions in 2028. 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.

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. 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.

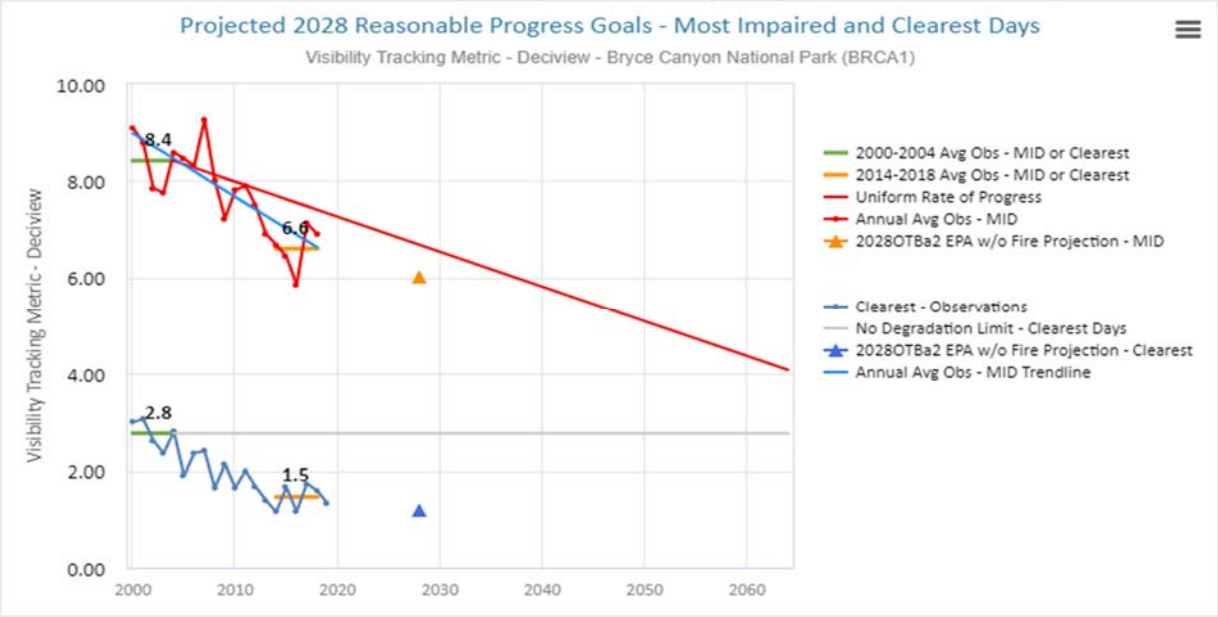


Figure 57: Projected 2028 RPG Bryce Canyon National Park

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 58: 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

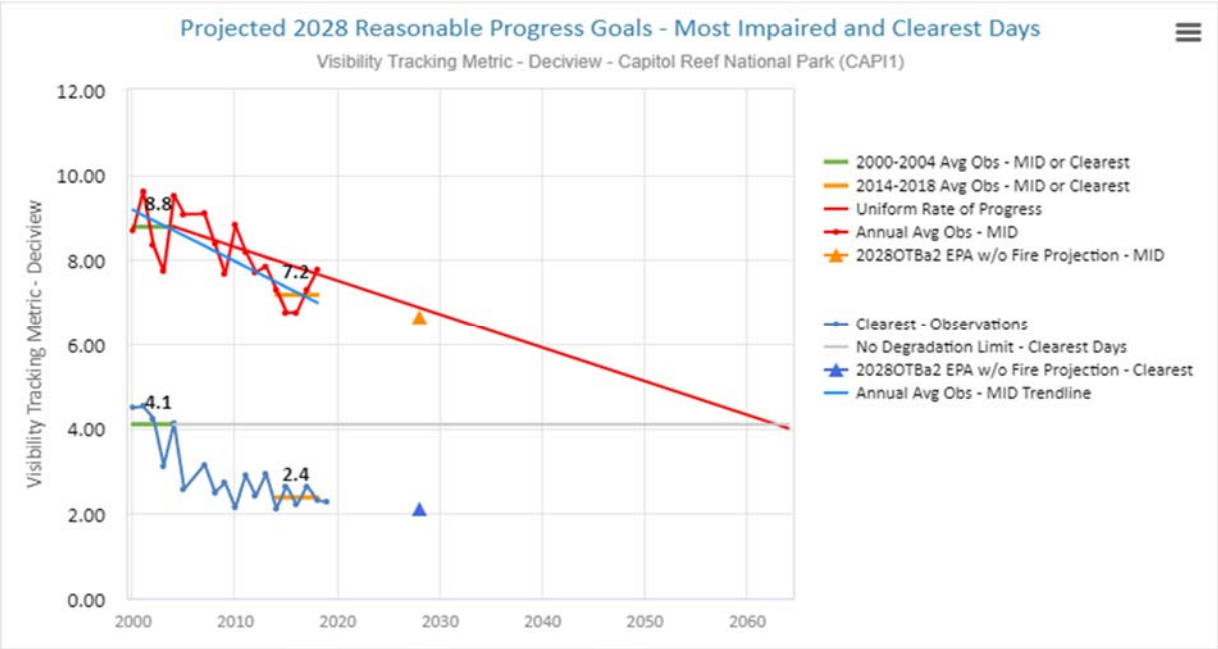


Figure 59: Projected 2028 RPG Capitol Reef National Park

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.

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 60: Projected 2028 RPG Zion National Park

8.C.5 Summary of URP Glidepaths

The table below summarizes the information from figures 57-60 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 46: 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.

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. The plant already has SNCR installed and has provided this control's efficiency data, which adheres to the plant's current emissions limit. 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. 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 finds SNCR and SCR not to be cost-effective at this time due to the uncertainty associated with future utilization of both plants. Instead, UDAQ is establishing mass-based emissions limits that reflect recent actual emissions and the 2028 "on-the-books" emissions projections modeled by WRAP and used in Utah's URP glidepath checks. 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. Part H. 23 (b) and (c). 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. 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. The implementation of this control determination is to be enforced through SIP Subsection IX. Part H. 23 (d). 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 NOx). 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. The implementation of this closure is to be enforced through SIP Subsection IX. Part H. 23 (a).

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.[169] 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.[170] 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.[171] 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.[172] 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.[173] Utah must include a description in their implementation period of how it addressed any comment provided by FLMs.[174]

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. See Appendix B for further documentation of interstate consultation and agreements.

Table 47: 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.

[169] *See* 40 CFR § 51.308 (d)(1)(iv)
[170] *See id*., § 51.308 (d)(3)(i)
[171] *See id*., § 51.308 (f)(2)(ii)(C)
[172] *See id*., § 51.308 (i)(ii)(2)
[173] *See id*., § 51.308 (i)(ii)(2)
[174] *See id*., § 51.308 (i)(4)

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.

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 48: 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.

9.C.1 FLM SIP Review[175]

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.

9.C.2 NPS Feedback Summary and UDAQ Responses[176]

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.

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

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 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 contacted Paradox Resources and is in the process of obtaining information from them that will be available for review in this SIP after the public commenting period when the SIP is brought to the AQB again.

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[177]. 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."[178] 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.

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.

[177] 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
[178] 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.

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[179] 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 requested additional information regarding the feasibility and cost-effectiveness of dry sorbent injection technology from Sunnyside and will include their response in the final draft of this SIP.

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[180]. 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

[179] Please refer to section 7.B to view the four factors used to determine control feasibility in this implementation period.
[180] Located in section 7.C.1 in Ash Grove's Evaluation Response

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 grow.h.

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 has issued an order to US Magnesium to obtain the information required to respond to these comments. US Magnesium has been given a response deadline of April 11th, 2022 and the information they provide will be included in the final draft of this SIP.

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.

    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[181]

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

[181] See Appendix D.3 to view the full USFS RH SIP review document

(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.

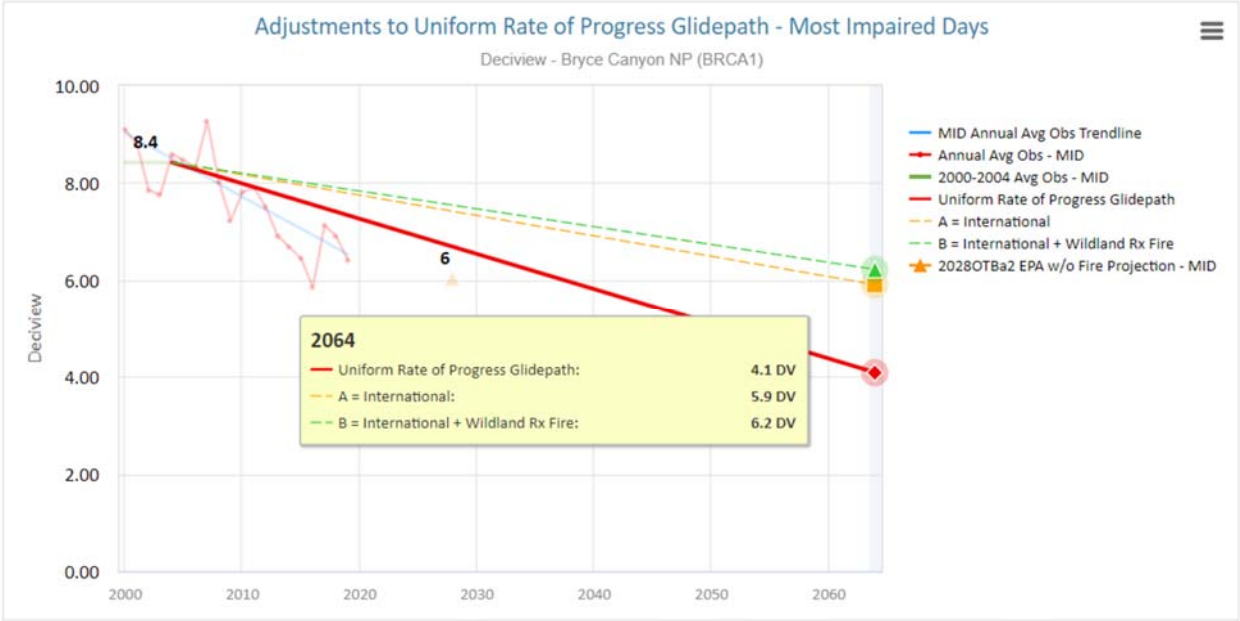


Figure 61: USFS Fire Glidepath Adjustment for Bryce Canyon

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 8th, 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.

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 49: 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.
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.

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 availability of the SIP draft will be published in the State Bulletin, posted on the UDAQ webpage and sent electronically through the RH listserv and the AQ board actions update.

9.G Comment Conclusions

Section to be completed once the commenting period has ended and all comments are addressed.

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)[182] and Utah's Continuous Emissions Monitoring Program[183] to track regional haze progress, participate in regional haze modeling efforts, and track emissions trends.

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:[184]

[182] 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
[183] Utah Admin. Code r. R307-170.

- 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

[i] See page 6 of https://gardner.utah.edu/wp-content/uploads/ERG2022-Full.pdf?x71849.

Utah State Implementation Plan

Emission Limits and Operating Practices

Section IX, Part H.21 and Part H.23

Adopted by the Air Quality Board [Insert Date]

H.21. General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, Regional Haze Requirements

a. Except as otherwise outlined in individual conditions of this Subsection IX.H.21 listed below, the terms and conditions of this Subsection IX.H.21 shall apply to all sources subsequently addressed in Subsection IX.H.22. Should any inconsistencies exist between these two subsections, the source specific conditions listed in IX.H.22 shall take precedence.

b. The definitions contained in R307-101-2, Definitions and R307-170-4, Definitions, apply to Section IX, Part H. In addition, the following definition also applies to Section IX, Part H.21 and 22:

   Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler. It is not necessary for fuel to be combusted for the entire 24-hour period.

c. The terms and conditions of R307-107-1 and R307-107-2 shall apply to all sources subsequently addressed in Subsection IX.H.22.

d. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. All records required by IX.H.21.c shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request.

e. All emission limitations listed in Subsections IX.H.22 shall apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.22. Each source shall submit a report of any deviation from the applicable requirements of Subsection IX.H, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be submitted in accordance with the requirements of R307-170, Continuous Emission Monitoring Program. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107.

f. Stack Testing:

   i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.22 <u>and IX.H.23</u> shall be performed in accordance with the following:

      A. Sample Location: The testing point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or the most recent version of the EPA-approved test method if approved by the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2, or ~~the most recent version of the~~ other EPA-approved testing methods ~~if approved by~~ acceptable to the Director.

C. Particulate (PM): 40 CFR 60, Appendix A, Method 5B, or the ~~most recent version of the~~ other EPA-approved testing methods ~~if approved by~~ acceptable to the Director. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. The back half condensables shall also be tested using Method 202. The back half condensables shall not be used for compliance demonstration but shall be used for inventory purposes.

D. Nitrogen Oxides (NOx): 40 CFR 60, Appendix A, Method 7E, or other EPA approved testing methods acceptable to the Director.

E. Calculations: To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.

F. ~~A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director.~~ Notification: The Director shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Director.

G. The source test protocol shall be approved by the Director prior to performing the tests. The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Director.

H. Source Operation and Testing Frequency: The production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

g. Continuous Emission and Opacity Monitoring.

i. For all continuous monitoring devices, the following shall apply:

A. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13.

B. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 13; and 40 CFR 60, Appendix B – Performance Specifications.

C. For any hour in which fuel is combusted in the unit, the owner/operator of each unit shall calculate the hourly average NOx concentration in lb/MMBtu.

D. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the current boiler operating day and the previous 29 successive boiler operating days.

E. An hourly average NOx emission rate in lb/MMBtu is valid only if the minimum number of data points, as specified in R307-170, is acquired by the owner/operator for both the pollutant concentration monitor (NOx) and the diluent monitor (O2 or CO2).

H.23. Source Specific Emission Limitations: Regional Haze Requirements, Reasonable Progress Controls

a. Intermountain Generation Station

i. Conditions on Units #1 and #2.

A. The owner/operator shall permanently close and cease operation of Intermountain Generation Station units #1 and #2 by December 31, 2027. The owner/operator shall notify the Director of the permanent closure of units #1 and #2 by no later than January 31, 2028.

b. PacifiCorp Hunter

i. The annual NO_x emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 10,514 tons/year based on a 12-month rolling total.

ii. As of January 1, 2025, the annual NOx emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 10,257 tons/year based on a 12-month rolling total.

iii. As of January 1, 2028, the annual NOx emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 10,001 tons/year based on a 12-month rolling total.

iv. The above NO_x limits shall be monitored in accordance with the procedures outlined in 40 CFR Part 52.21(aa)(12) and at a minimum shall be done by summing up emissions as follows:

A. For Units #1, #2 and #3 main boiler stacks, PacifiCorp's reporting to EPA's Acid Rain Emissions data base for NO_x in pounds per hour obtained from the boilers' CEM data shall be used to calculate NO_x emission rates.

B. For Units #1, #2 and #3 emergency diesel-fired equipment, emissions shall be calculated by multiplying the NO_x emission factor from the latest edition of EPA's emission factors compilation AP-42 and hours of operation. Records documenting equipment usage shall be kept in a log, and they shall show the date the equipment was used and the duration in hours of operation.

C. For the record keeping requirements of each limit, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(13).

D. For record submittal, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(14).

v. To determine compliance with the 12-month rolling NO_x limits, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation.

vi. Emissions of SO_2 from Unit #1 and Unit #2 shall not exceed the following limits:

A. 1.2 lb/MMBtu heat input for any 3-hour period

B. 0.12 lb/MMBtu heat input based on a 30-day rolling average

vii. Emissions of SO_2 from Unit #3 shall not exceed 0.12 lb/MMBtu heat input based on a 30-day rolling period

viii. The SO_2 emissions shall be determined by CEM as outlined in IX.H.21.g.

c. PacifiCorp Huntington

i. The annual NO_x emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,210 tons/year based on a 12-month rolling total.

ii. As of January 1, 2025, the annual NOx emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,151 tons/year based on a 12-month rolling total

iii. As of January 1, 2028, the annual NOx emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,091 tons/year based on a 12-month rolling total.

iv. The above NO_x limits shall be monitored in accordance with the procedures outlined in 40 CFR Part 52.21(aa)(12) and at a minimum shall be done by summing up emissions as follows:

A. For Units #1 and #2 main boiler stacks, PacifiCorp's reporting to EPA's Acid Rain Emissions data base for NO_x in pounds per hour obtained from the boilers' CEM data shall be used to calculate NO_x emission rates.

B. For Units #1 and #2 emergency diesel-fired equipment, emissions shall be calculated by multiplying the NO_x emission factor from the latest edition of EPA's emission factors compilation AP-42 and hours of operation. Records documenting equipment usage shall

be kept in a log, and they shall show the date the equipment was used and the duration in hours of operation.

C. For the record keeping requirements of each limit, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(13).

D. For record submittal, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(14).

v. To determine compliance with the 12-month rolling NO_x limits, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation.

vi. Emissions of SO_2 from Unit #1 shall not exceed 0.12 lb/MMBtu heat input (595 lb/hr) on a 30-day rolling average except during periods of startup, shutdown, maintenance/planned outage or malfunction.

vii. Emissions of SO_2 from Unit #2 shall not exceed 0.12 lb/MMBtu heat input for any 24-hour block average except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

viii. The SO_2 emissions shall be determined by CEM as outlined in IX.H.21.g.

d. US Magnesium

i. The owner/operator shall install and operate a flue gas recirculation (FGR) system on the 60 MMBtu/hr (Riley) boiler no later than January 1, 2028.

ii. Following installation of the FGR system, total annual NO_x emissions from the Riley boiler shall not exceed 22.6 tons per rolling 12-month period.

iii. The emission rate from the Riley boiler shall be determined by stack test. Stack testing shall be performed at least once every three years.

iv. To determine compliance with the 12-month rolling NO_x limit, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation. To calculate the monthly NO_x emissions, the owner/operator shall multiply the lb/hr NO_x emission rate from the most recent stack test by the hours of operation of the Riley boiler for each month.

State of Utah
Administrative Rule Analysis
Revised November 2021

NOTICE OF PROPOSED RULE		
TYPE OF RULE: New ___; Amendment _X__; Repeal ___; Repeal and Reenact ___		
	Title No. - Rule No. - Section No.	
Utah Admin. Code Ref (R no.):	**R307-110**	**Filing ID (Office Use Only)**
Changed to Admin. Code Ref. (R no.):	**R**	

Agency Information

1. Department:	Department of Environmental Quality	
Agency:	Division of Air Quality	
Room no.:		
Building:	MASOB	
Street address:	195 North 1950 West	
City, state and zip:	Salt Lake City, Utah 84116	
Mailing address:	P.O. Box 144820	
City, state and zip:	Salt Lake City, Utah 84114-4820	
Contact person(s):		
Name:	**Phone:**	**Email:**
Bo Wood	385-499-3416	rwood@utah.gov
Chelsea Cancino	801-536-4015	ccancino@utah.gov
Glade Sowards	801-536-4020	gladesowards@utah.gov
Please address questions regarding information on this notice to the agency.		

General Information

2. Rule or section catchline:

R307-110. General Requirements: State Implementation Plan

3. Purpose of the new rule or reason for the change (Why is the agency submitting this filing?)**:**

EPA's Regional Haze Rule (RHR) requires states to submit a State Implementation Plan (SIP) demonstrating reasonable progress towards achieving natural visibility by 2064 in Utah's five Class I Areas (CIAs), which include all five of the national parks in the State. As part of this SIP, the state must conduct an emissions controls determination to identify its long-term strategy (LTS) to achieving the 2064 natural conditions goal. This rule is being amended incorporate by reference Section XX.A: Regional Haze Second Implementation Period and amendments to Amend SIP Section IX Control Measures for Area and Point Sources, Part H, Emission Limits into the Utah State Implementation Plan (SIP).

4. Summary of the new rule or change (What does this filing do? If this is a repeal and reenact, explain the substantive differences between the repealed rule and the reenacted rule)**:**

This amendment changes the "most recently amended" date in R307-110-17 and R307-110-28 to July 6, 2022, incorporating by reference the requirements of Section XX.A: Regional Haze Second Implementation Period and Section IX: Control Measures for Area and Point Sources, Part H, Emissions Limits of the Utah State Implementation Plan. The reasonable progress determination of these Sections requires the following measures to meet the State's LTS:

1. Establishing mass-based annual NOx and SO2 emissions limits for Hunter Power Plant based upon recent actual emissions and plant utilization levels,
2. Establishing mass-based annual NOx and SO2 emissions limits for the Huntington Power Plant based upon recent actual emissions and plant utilization levels,
3. Establishing a federally enforceable closure date for the coal-fired boilers at the Intermountain Generation Station (IGS) based on the Intermountain Power Agency's (IPA's) 2021 notice of intent (NOI) to replace the coal-fired boilers with combined cycle natural gas turbines, and
4. Requiring the retrofit of U.S. Magnesium's Rowley Plant's Riley boiler with flue gas recirculation (FGR)

Fiscal Information

5. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:

A) State budget:

Because the Hunter and Huntington Power Plants are already operating at approximately at the emissions and utilization levels required by the proposed SIP limits, we anticipate no fiscal impacts to the State budget associated with these facilities. Because IPA has submitted an NOI to replace the coal-fired boilers at the IGS, the proposed closure date for the IGS coal-fired boilers does not, in itself, result in the closure of the facility, but rather establishes federal enforceability of the already planned boiler closures as required by the RHR and the Clean Air Act. As a result, we anticipate no fiscal impacts to the State budget associated with the IGS. The requirement to install FGR at the Riley Boiler of U.S. Magnesium's Rowley Plant may result in small fiscal impacts to the State budget resulting from economic activity associated with FGR installation. The direction of such impacts could be positive or negative depending on the extent to which installation of FGR could increase economic activity within the State, with a potential increase in State revenue, and/or decrease economic activity while the unit is down for installation. While it is difficult to estimate the net effect of such impacts, we anticipate that it is likely small due to the relative cost of FGR installation relative to overall economic activity in Utah.

B) Local governments:

Because the Hunter and Huntington Power Plants are already operating at approximately at the emissions and utilization levels required by the proposed SIP limits, we anticipate no fiscal impacts to local governments associated with these facilities. Because IPA has submitted an NOI to replace the coal-fired boilers at the IGS, the proposed closure date for the IGS coal-fired boilers does not, in itself, result in the closure of the facility, but rather establishes federal enforceability of the already planned boiler closures as required by the RHR and the Clean Air Act. As a result, we anticipate no fiscal impacts to local governments associated with the IGS (e.g, City of Delta, Millard County, etc.). The requirement to install FGR at the Riley Boiler of U.S. Magnesium's Rowley Plant may result in small fiscal impacts to local governments resulting from economic activity associated with FGR installation. The direction of such impacts could be positive or negative depending on the extent to which installation of FGR could increase economic activity in local government jurisdictions, with a potential increase local government revenue, and/or decrease economic activity while the unit is down for installation. While it is difficult to estimate the net effect of such impacts, we anticipate that it is likely small.

C) Small businesses ("small business" means a business employing 1-49 persons)**:**

Some small businesses may see small increases or decreases in economic activity associated with the installation of FGR on the Riley Boiler at the U.S. Magnesium Rowley Plant. For example, the service industry near the Rowley plant may see increased patronage during the period of FGR installation, or may see small decreases in patronage if the installation process leads to traffic impacts or short-term changes to labor patterns while the boiler is being retrofitted. It is difficult to estimate the net impact to small businesses, but we anticipate that it is likely small unless those businesses are directly involved with the FGR installation

D) Non-small businesses ("non-small business" means a business employing 50 or more persons)**:**

The installation of FGR on the Riley Boiler at the U.S. Magnesium Rowley Plant is anticipated to require a one-time cost of $615,300 and approximately $3,100 per year thereafter. However, since the installation of these controls is not mandatory until January, 2028, the fiscal impact in FY2022, FY2023, and FY2024 is unknown. Companies that provide the equipment and installation of FGR at the facility will likely see an increase in revenue.

E) Persons other than small businesses, non-small businesses, state, or local government entities ("person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an ***agency***)**:**

Some individuals working for U.S. Magnesium or for firms providing FGR installation equipment and services could see positive or negative impacts associated with the retrofit of the Riley Boiler. Such impacts are likely to affect a relatively small number of individuals and are likely to be short in duration.

F) Compliance costs for affected persons (How much will it cost an impacted entity to adhere to this rule or its changes?)**:**

The installation of FGR on the Riley Boiler at the U.S. Magnesium Rowley Plant is anticipated to cost the company $615,300 for initial installation and an additional $3,100 per year in ongoing maintenance over the life of the boiler.

G) Comments by the department head on the fiscal impact this rule may have on businesses (Include the name and title of the department head):

6. A) Regulatory Impact Summary Table (This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they will not be included in this table. Inestimable impacts will be included in narratives above.)

Regulatory Impact Table

Fiscal Cost	**FY2022**	**FY2023**	**FY2024**
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Cost	**$0**	**$0**	**$0**

Fiscal Benefits			
State Government	$0	$0	$0
Local Governments	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Benefits	**$0**	**$0**	**$0**
Net Fiscal Benefits	**$0**	**$0**	**$0**

B) Department head approval of regulatory impact analysis:

The Executive Director of the Department of Environmental Quality, Kim Shelley, has reviewed and approved this fiscal analysis.

Citation Information

7. Provide citations to the statutory authority for the rule. If there is also a federal requirement for the rule, provide a citation to that requirement:

19-2-104		
40 CFR 51.308(f)		

Incorporations by Reference Information

(If this rule incorporates more than two items by reference, please include additional tables.)

8. A) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**

	First Incorporation
Official Title of Materials Incorporated (from title page)	Utah Regional Haze State Implementation Plan
Publisher	Division of Air Quality, Utah Dept. of Environmental Quality
Date Issued	April, 2022
Issue, or version	Second Implementation Period

B) This rule adds, updates, or removes the following title of materials incorporated by references (a copy of materials incorporated by reference must be submitted to the Office of Administrative Rules; *if none, leave blank*)**:**

	Second Incorporation
Official Title of Materials Incorporated (from title page)	
Publisher	
Date Issued	
Issue, or version	

Public Notice Information

9. The public may submit written or oral comments to the agency identified in box 1. (The public may also request a hearing by submitting a written request to the agency. See Section 63G-3-302 and Rule R15-1 for more information.)

A) Comments will be accepted until (mm/dd/yyyy)**:**	5/31/2022

B) A public hearing (optional) will be held:

On (mm/dd/yyyy)**:**	**At** (hh:mm AM/PM)**:**	**At** (place)**:**
May 26, 2022	10:30AM	https://meet.google.com/thd-ffia-etr?hs=122&authuser=0

10. This rule change MAY become effective on (mm/dd/yyyy)**:**	07/07/2022

NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date. To make this rule effective, the agency must submit a Notice of Effective Date to the Office of Administrative Rules on or before the date designated in Box 10.

Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 302, 303, and 402. Incomplete forms will be returned to the agency for completion, possibly delaying publication in the *Utah State Bulletin* and delaying the first possible effective date.			
Agency head or designee, and title:	Bryce C. Bird, Director	**Date** (mm/dd/yyyy)**:**	

R307. Environmental Quality, Air Quality.
R307-110. General Requirements: State Implementation Plan.

R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits and Operating Practices, as most recently amended by the Utah Air Quality Board on ~~December 2, 2020~~ July 6, 2022, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

R307-110-28. Regional Haze.

The Utah State Implementation Plan, Section XX, Regional Haze, as most recently amended by the Utah Air Quality Board on ~~June 24, 2019~~ July 6, 2022, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

KEY: air pollution, PM10, PM2.5, ozone
Date of Last Change: December 3, 2020
Notice of Continuation: December 1, 2021
Authorizing, and Implemented or Interpreted Law: 19-2-104

Regional Haze SIP Proposal

Chelsea Cancino

1 Overview

Regional Haze 101

Regional Haze

- Haze is one of the most basic forms of visibility-decreasing air pollution
  - Decreases visual range
- Caused by PM, NO_x, SO_2, and VOCs that scatter light
- Main anthropogenic sources
  - Mobile and industry

Regional Haze Rule (RHR)

- 40 CFR 51.308/309
  - Requires a State Implementation Plan (SIP)
- Class I Areas (CIAs) - EPA designated national parks and wilderness areas where visibility is protected
- Overarching goal: Natural visibility by 2064
- Two prongs for Reasonable Progress
  - Improve the number of most impaired days (MID)
  - No degradation of clearest days

Utah's Class I Areas

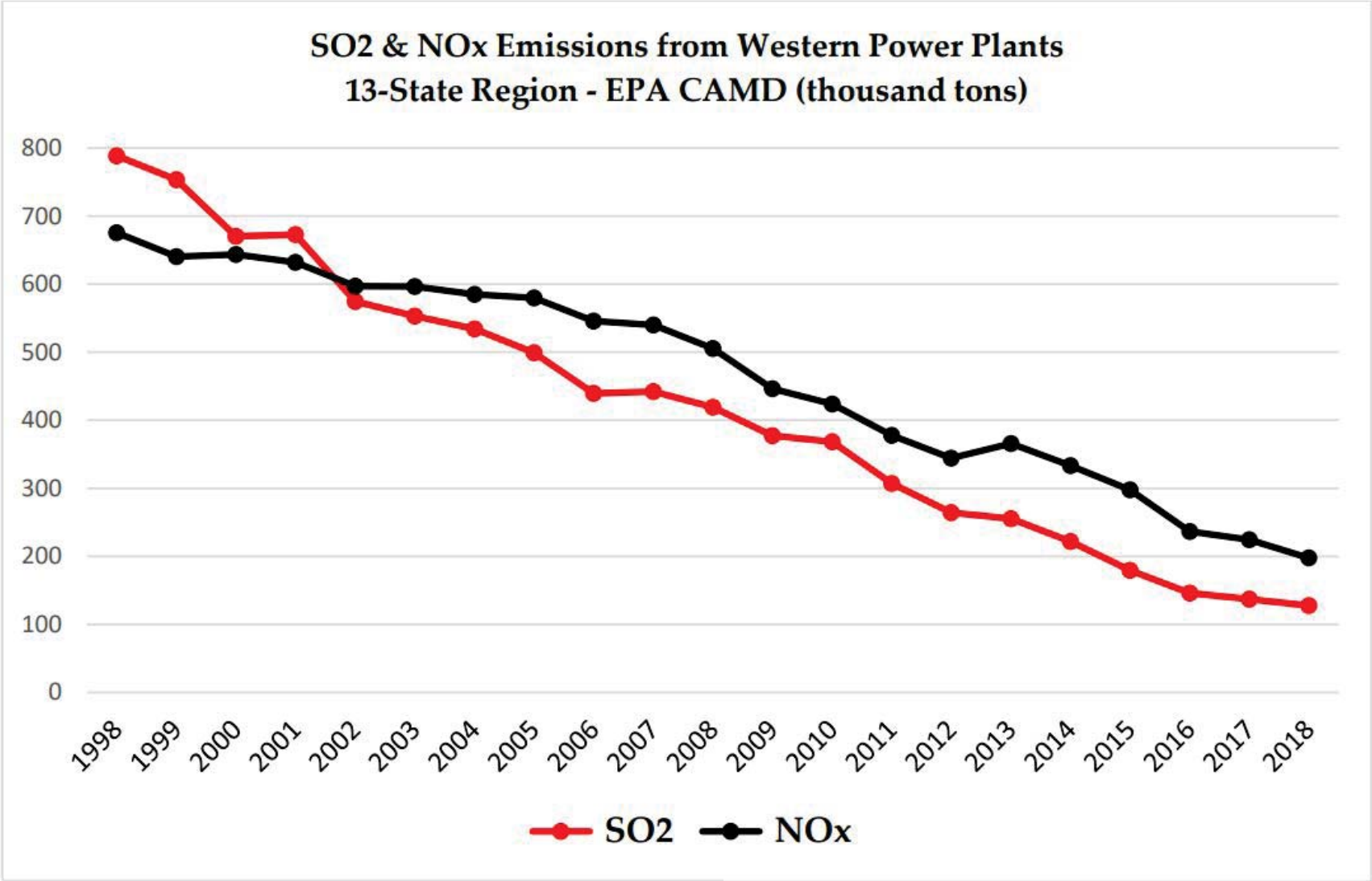
- Arches
- Canyonlands
- Capitol Reef
- Bryce Canyon
- Zion

2 Regional Haze Progress

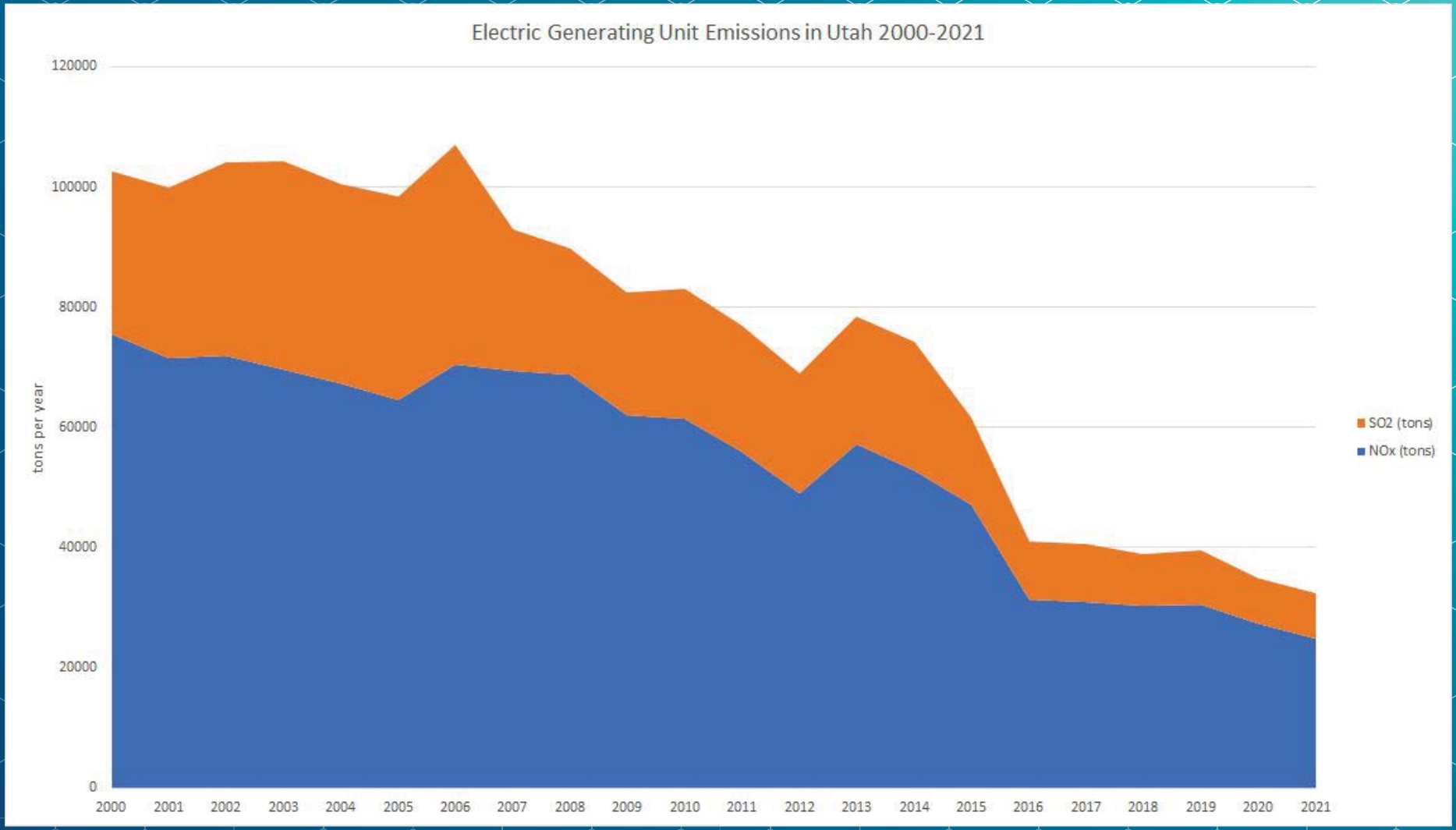
in Utah's Class I Areas

Utah's Regional Haze History

- **1991** — Grand Canyon Visibility Transport Commission
- **2003** — Utah adopts RHR requirements
- **2008** — Utah adopts BART for NOx and PM
- **2011** — SO_2 milestone updated
- **2015** — 1st Implementation Period
- **2019** — SIP revision defending 2015 "Better-than-BART"
- **2021** — 2nd Implementation Period



Source: CNEE for WESTAR-WRAP



Source: EPA Clean Air Markets AMPD

3 2nd Implementation Period

Goals and Focus

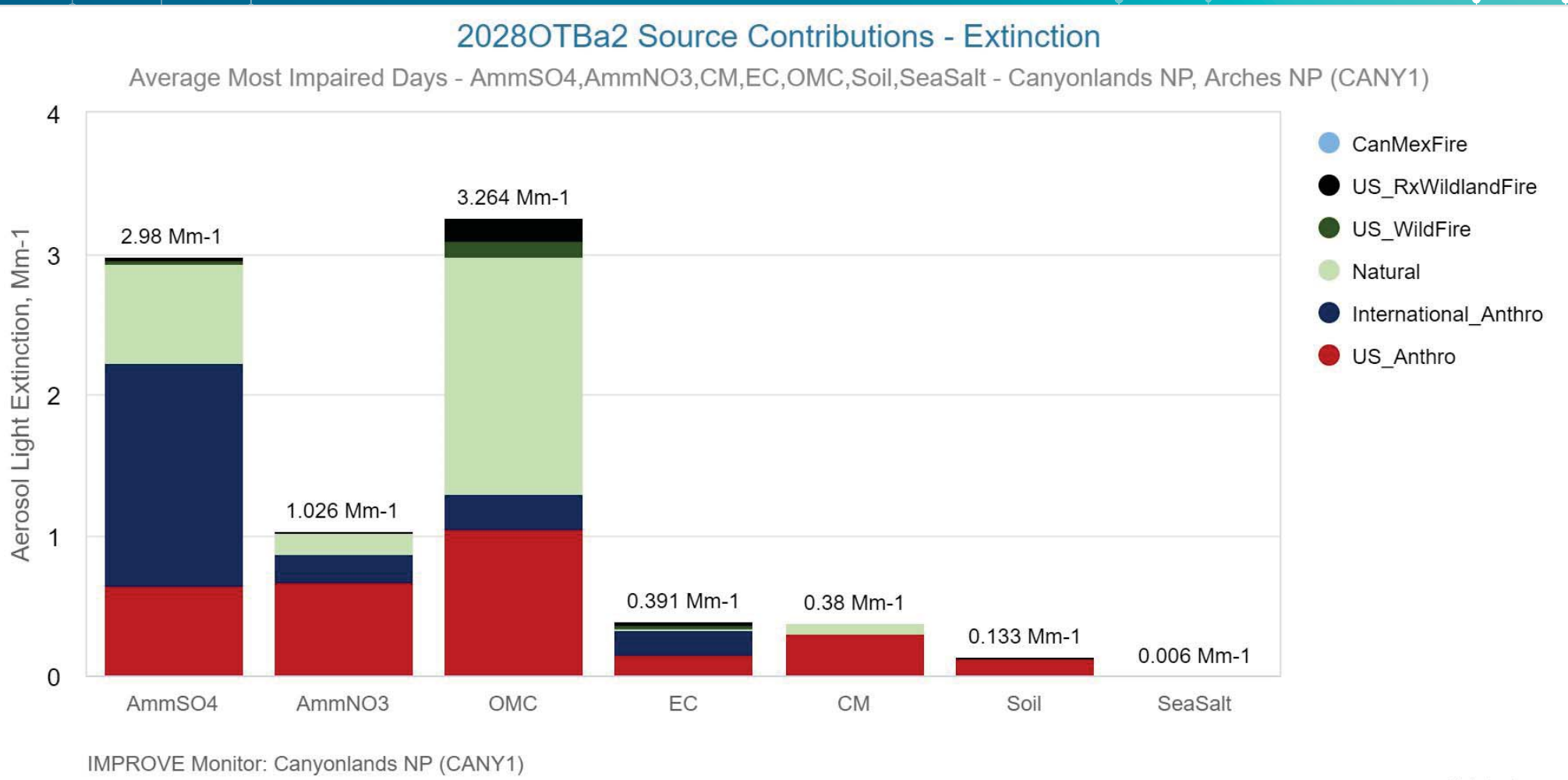
Second Implementation Period Goals

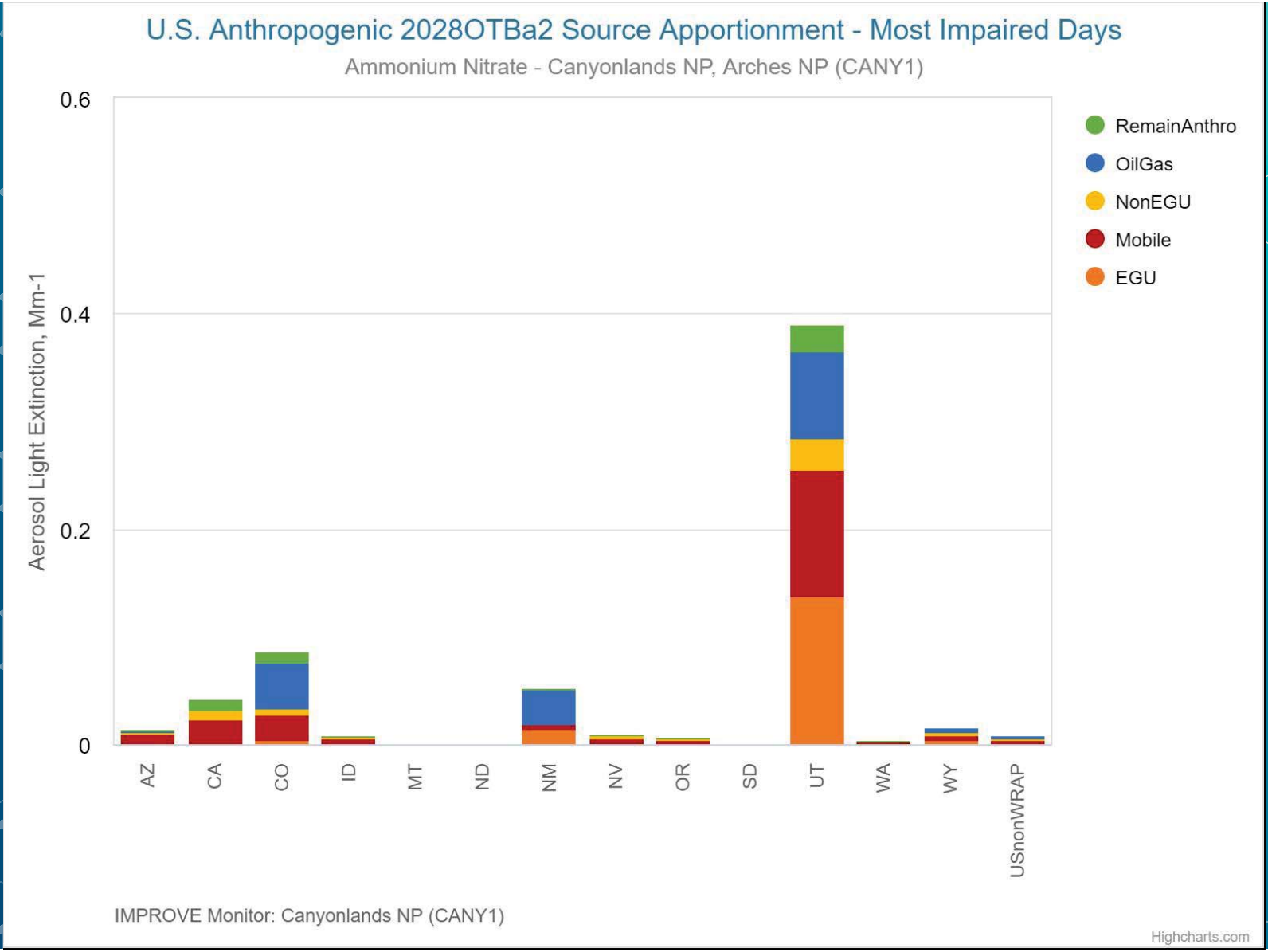
- **Scope:** 2018-2028
- **Goals:**
  - Protect visibility in our CIAs
  - Implement controls necessary for reasonable progress

Focus: U.S. Anthropogenic sources

Four-Factor Analysis

Cost/Ton	Time for Compliance
Remaining Useful Life	Non-Air Impacts

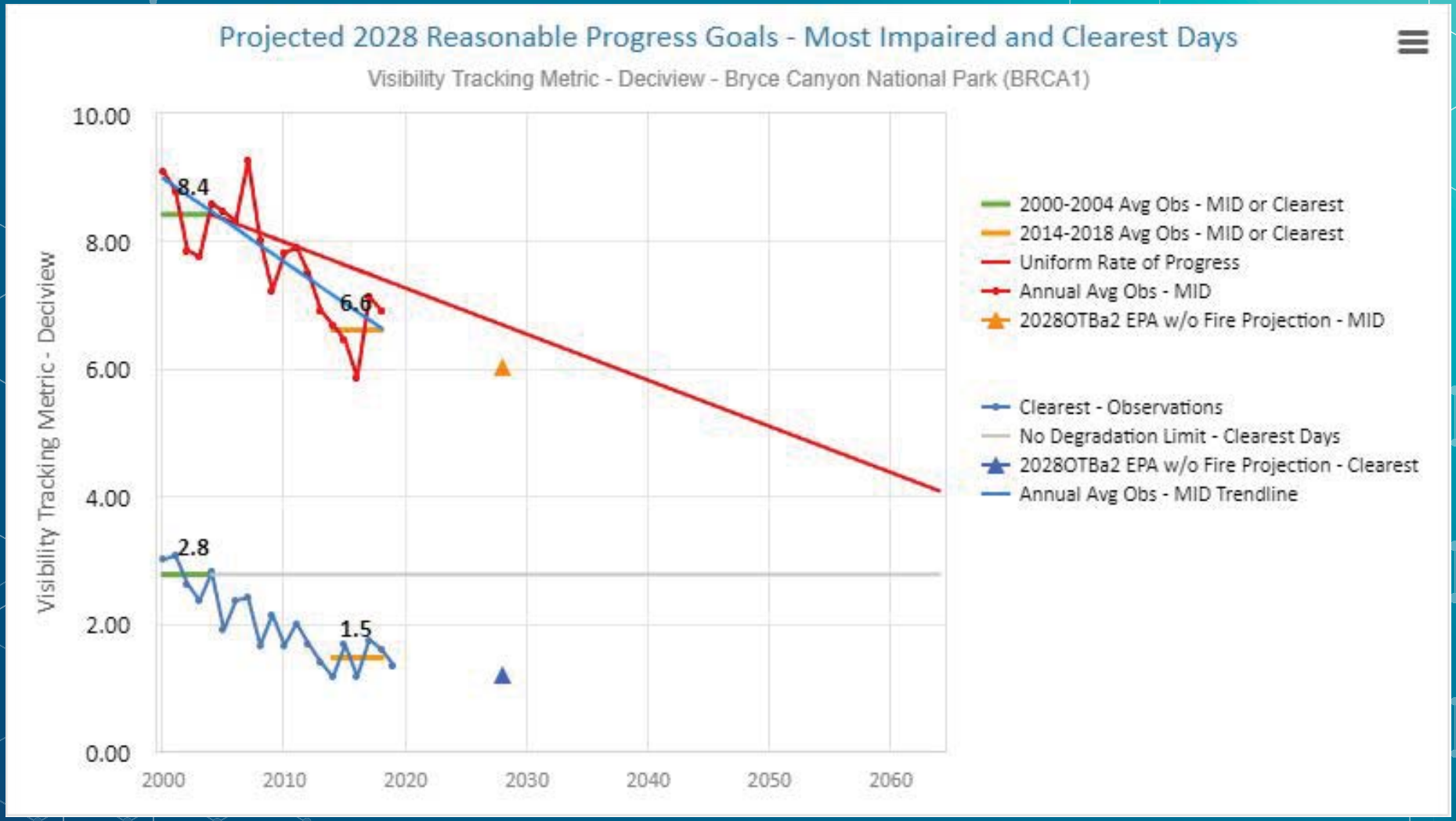

2028OTBa2 Source Contributions - Extinction
Average Most Impaired Days - AmmSO4,AmmNO3,CM,EC,OMC,Soil,SeaSalt - Canyonlands NP, Arches NP (CANY1)
Aerosol Light Extinction, Mm-1
4
3
2
1
0
2.98 Mm-1
1.026 Mm-1
3.264 Mm-1
0.391 Mm-1
0.38 Mm-1
0.133 Mm-1
0.006 Mm-1
AmmSO4
AmmNO3
OMC
EC
CM
Soil
SeaSalt
CanMexFire
US_RxWildlandFire
US_WildFire
Natural
International_Anthro
US_Anthro
IMPROVE Monitor: Canyonlands NP (CANY1)
Highcharts.com

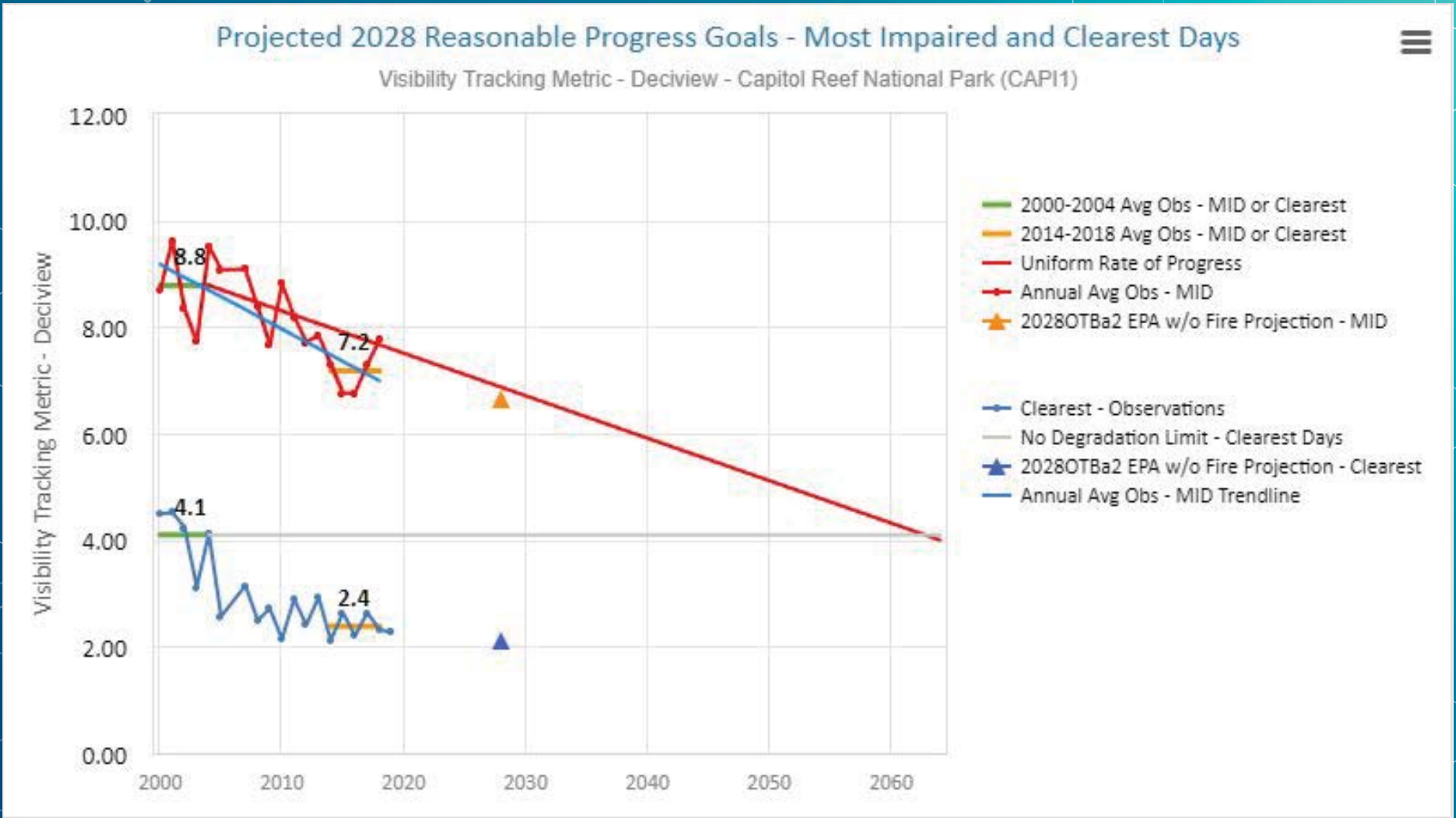

U.S. Anthropogenic 2028OTBa2 Source Apportionment - Most Impaired Days
Ammonium Nitrate - Canyonlands NP, Arches NP (CANY1)
Aerosol Light Extinction, Mm-1
0.6
0.4
0.2
0
AZ
CA
CO
ID
MT
ND
NM
NV
OR
SD
UT
WA
WY
USnonWRAP
RemainAnthro
OilGas
NonEGU
Mobile
EGU
IMPROVE Monitor: Canyonlands NP (CANY1)
Highcharts.com

4 Glidepaths

Uniform Rate of Progress and Reasonable Progress Goals


Projected 2028 Reasonable Progress Goals - Most Impaired and Clearest Days
Visibility Tracking Metric - Deciview - Canyonlands National Park,Arches National Park (CANY1)
Visibility Tracking Metric - Deciview
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2000
2010
2020
2030
2040
2050
2060
8.8
6.8
3.7
2.2
2000-2004 Avg Obs - MID
2014-2018 Avg Obs - MID
Uniform Rate of Progress
Annual Avg Obs - MID
2028OTBa2 EPA w/o Fire Projection - MID
Clearest - Observations
No Degradation Limit - Clearest Days
2028OTBa2 EPA w/o Fire Projection - Clearest
Annual Avg Obs - MID Trendline


Projected 2028 Reasonable Progress Goals - Most Impaired and Clearest Days
Visibility Tracking Metric - Deciview - Bryce Canyon National Park (BRCA1)
Visibility Tracking Metric - Deciview
10.00
8.00
6.00
4.00
2.00
0.00
2000
2010
2020
2030
2040
2050
2060
8.4
6.6
2.8
1.5
2000-2004 Avg Obs - MID or Clearest
2014-2018 Avg Obs - MID or Clearest
Uniform Rate of Progress
Annual Avg Obs - MID
2028OTBa2 EPA w/o Fire Projection - MID
Clearest - Observations
No Degradation Limit - Clearest Days
2028OTBa2 EPA w/o Fire Projection - Clearest
Annual Avg Obs - MID Trendline


Projected 2028 Reasonable Progress Goals - Most Impaired and Clearest Days
Visibility Tracking Metric - Deciview - Capitol Reef National Park (CAPI1)
Visibility Tracking Metric - Deciview
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2000
2010
2020
2030
2040
2050
2060
8.8
7.2
4.1
2.4
2000-2004 Avg Obs - MID or Clearest
2014-2018 Avg Obs - MID or Clearest
Uniform Rate of Progress
Annual Avg Obs - MID
2028OTBa2 EPA w/o Fire Projection - MID
Clearest - Observations
No Degradation Limit - Clearest Days
2028OTBa2 EPA w/o Fire Projection - Clearest
Annual Avg Obs - MID Trendline


Projected 2028 Reasonable Progress Goals - Most Impaired and Clearest Days
Visibility Tracking Metric - Deciview - Zion National Park (ZICA1)
Visibility Tracking Metric - Deciview
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2000
2010
2020
2030
2040
2050
2060
10.4
8.7
4.5
3.9
2000-2004 Avg Obs - MID or Clearest
2014-2018 Avg Obs - MID or Clearest
Uniform Rate of Progress
Annual Avg Obs - MID
2028OTBa2 EPA w/o Fire Projection - MID
Clearest - Observations
No Degradation Limit - Clearest Days
Annual Avg Obs - MID Trendline

Glidepath Considerations

- The Uniform Rate of Progress is not a “Safe Harbor”
- 2028OTBa2 projection is based off of recent actual emissions
  - Maintain and improve recent emissions

5 Facility Selections

Q/d and WEP AOI Analysis

Emissions/Distance to CIA (Q/d) Results

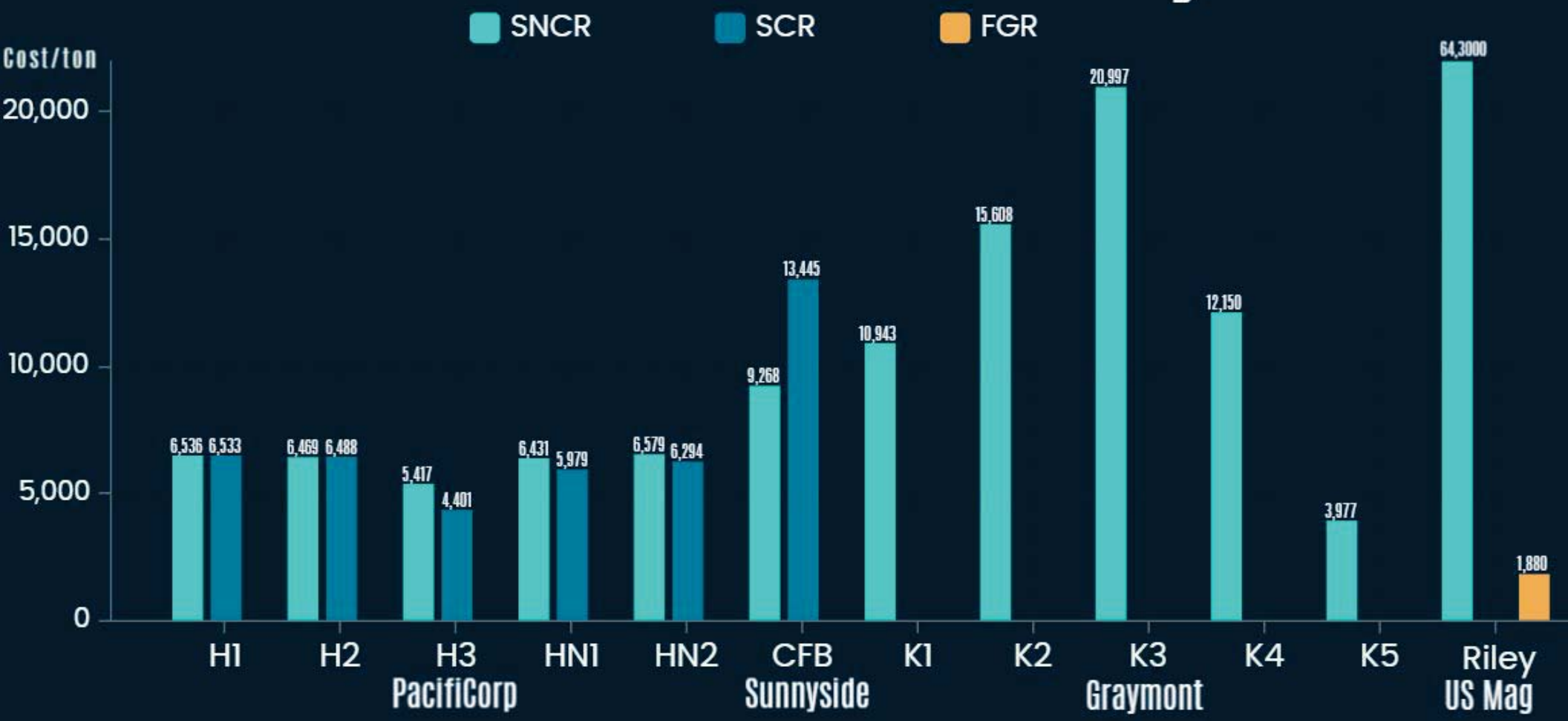
Facility	Combined Q/d
PacifiCorp- Hunter Power Plant	216.1
PacifiCorp- Huntington Power Plant	105.5
Sunnyside Cogeneration - Sunnyside	15.2
Graymont - Cricket Mountain Plant	9.0
US Magnesium LLC- Rowley Plant	7.4
Ash Grove - Leamington Cement Plant	6.9
Intermountain Power Service Corporation- Intermountain Generation Station*	193.6
Kennecott Utah Copper - Mine & Copperton Concentrator*	22.1
CCI Paradox Midstream, LLC: Lisbon Plant*	20.9
Kennecott Utah Copper - Power Plant Lab*	11.8

** These facilities were ultimately excluded from four-factor analysis due to closure, modifications, or recent controls related to other programs (e.g., PM2.5 SIP)*

6 Control Costs

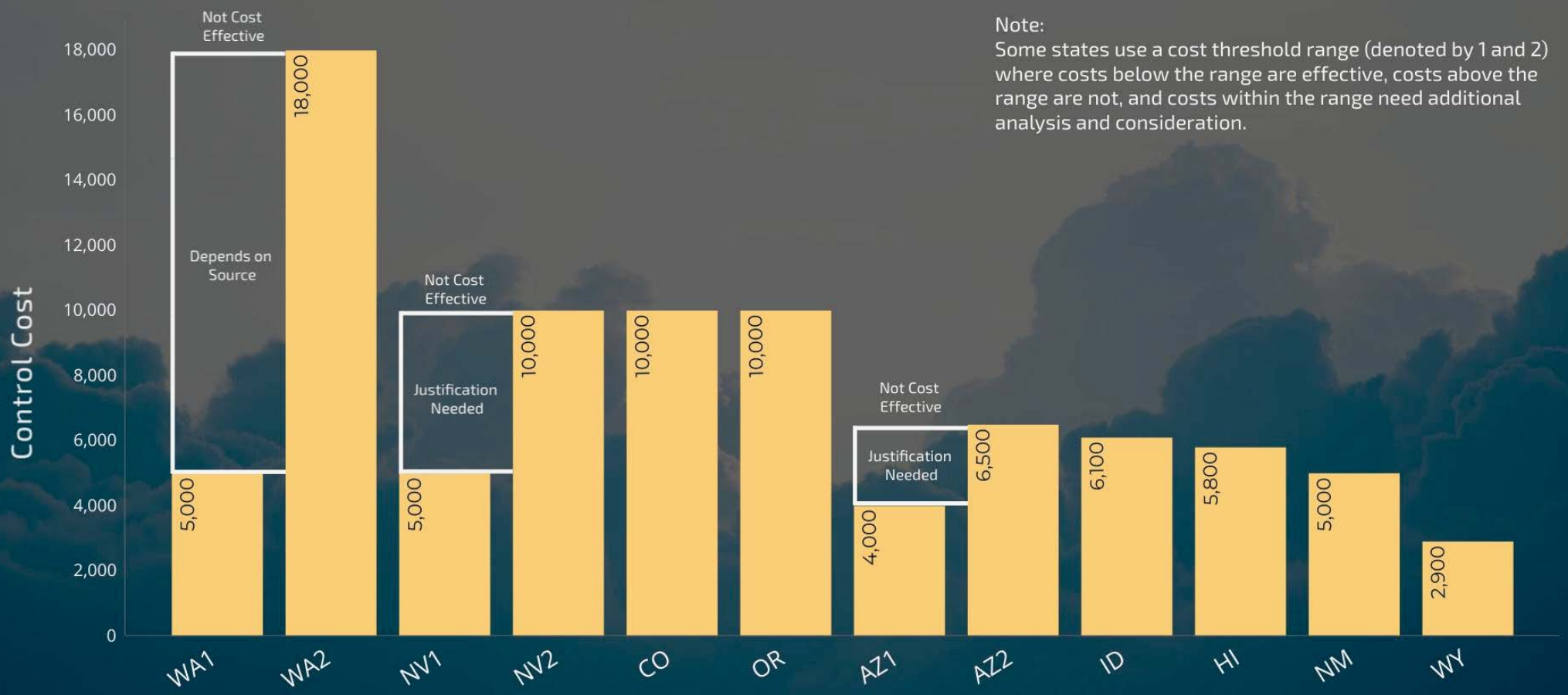
Control Feasibility and Threshold Justification

Control Cost Summary



Control Cost Threshold Comparison

Cost effectiveness thresholds used by other states



Note:
Some states use a cost threshold range (denoted by 1 and 2) where costs below the range are effective, costs above the range are not, and costs within the range need additional analysis and consideration.

7 Reasonable Progress Determinations

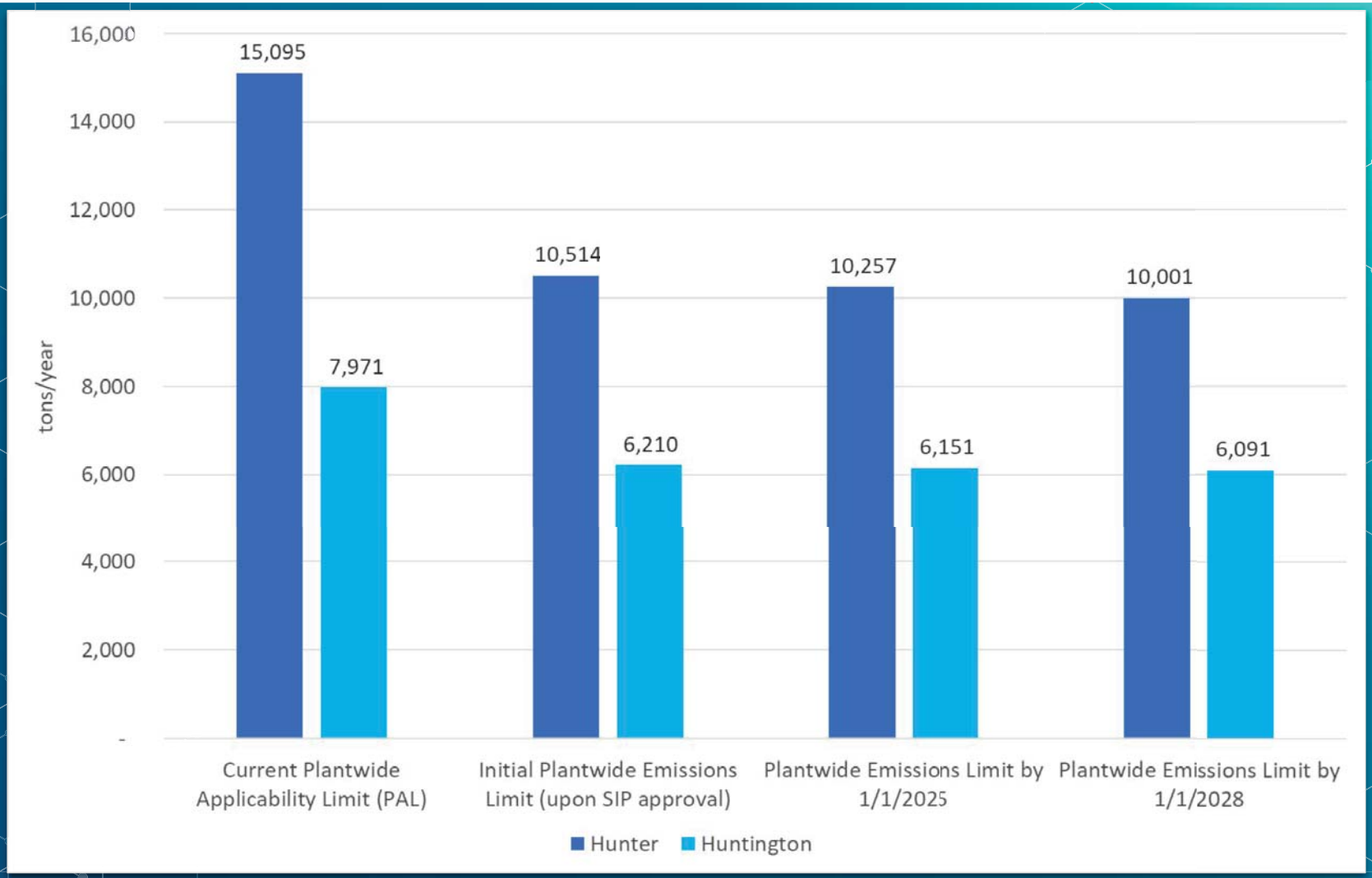
Controls and Emissions Limits for the 2nd Implementation Period

Reasonable Progress Determinations

- PacifiCorp - Hunter & Huntington Power Plants
  - New emissions limits (NO_x and SO_2)
    - Emissions will be kept below control-cost feasibility levels and recent trends
- Intermountain Power Service Corporation- IGS
  - Units 1 & 2 to close by 12/31/2027
- US Magnesium - Rowley Plant
  - Flue Gas Recirculation installation

8 Controls Determination Enforcement

SIP Part H



PacifiCorp NO_x Limits

2028 Reduction from PAL: -33.7% for Hunter; -23.6% for Huntington

PacifiCorp

- Permitted SO_2 limits made enforceable in SIP

Emissions Limit (lb/MMBtu)	Hunter 1	Hunter 2	Hunter 3
3-Hour Period Emissions Limit	1.2	1.2	
30-Day Rolling Average Limit	0.12	0.12	0.12*

Emissions Limit (lb/MMBtu)	Huntington 1	Huntington 2
24-Hour Block Average Emissions Limit		0.12
30-Day Rolling Average Limit	0.12	

* The original Board packet mistakenly included a 1.2 lb/MMbtu 3-hour limit for Unit 3

Intermountain Generation Station

- Conditions on Units #1 and #2.
  - IGS shall permanently close and cease operation of units 1 and 2 by December 31, 2027.

US Magnesium

- Flue gas recirculation (FGR) system on the Riley boiler no later than January 1, 2028.
- NOx emissions limit: 22.6 tpy

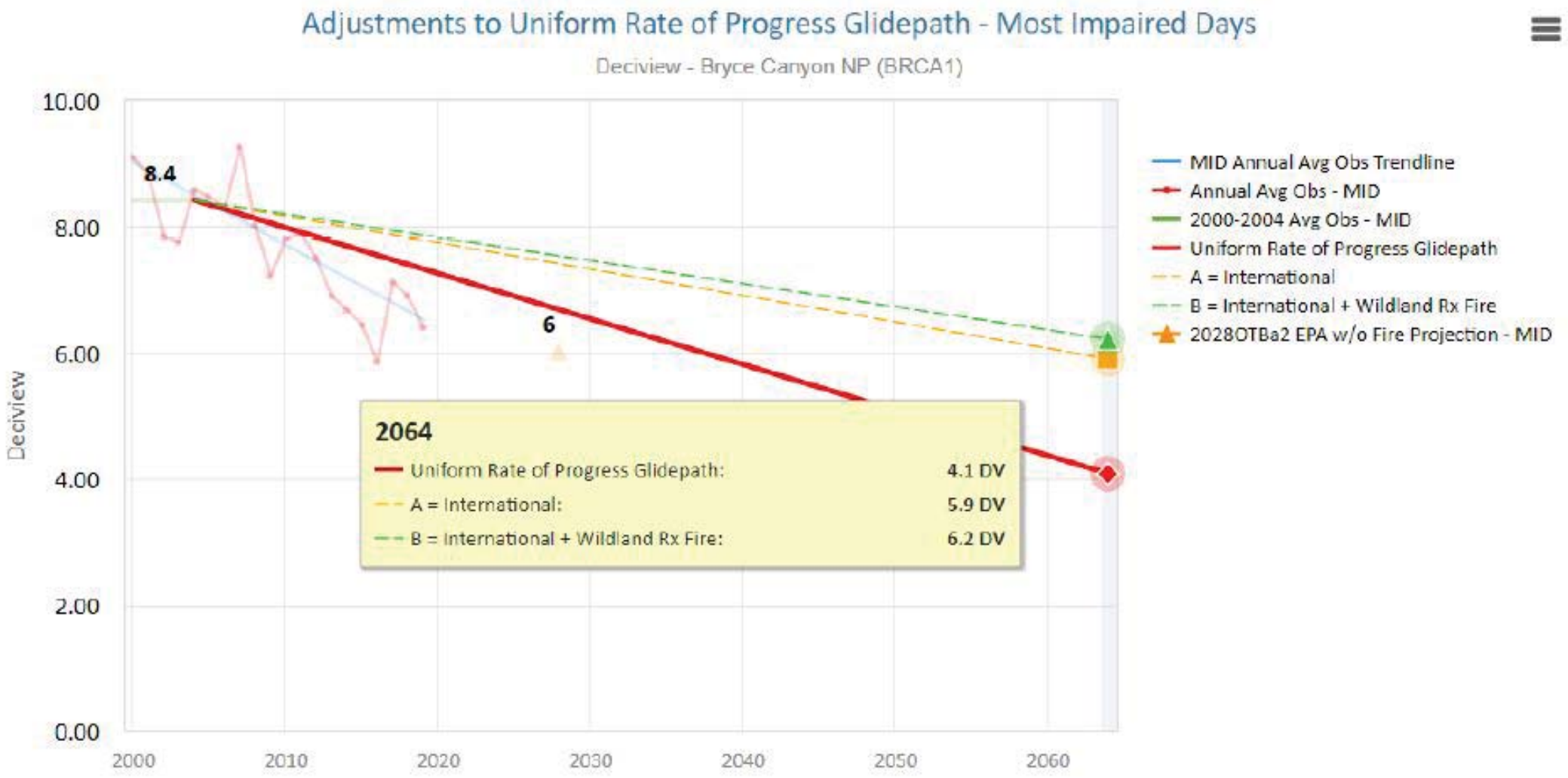
9 FLM Comments

National Parks Service Feedback

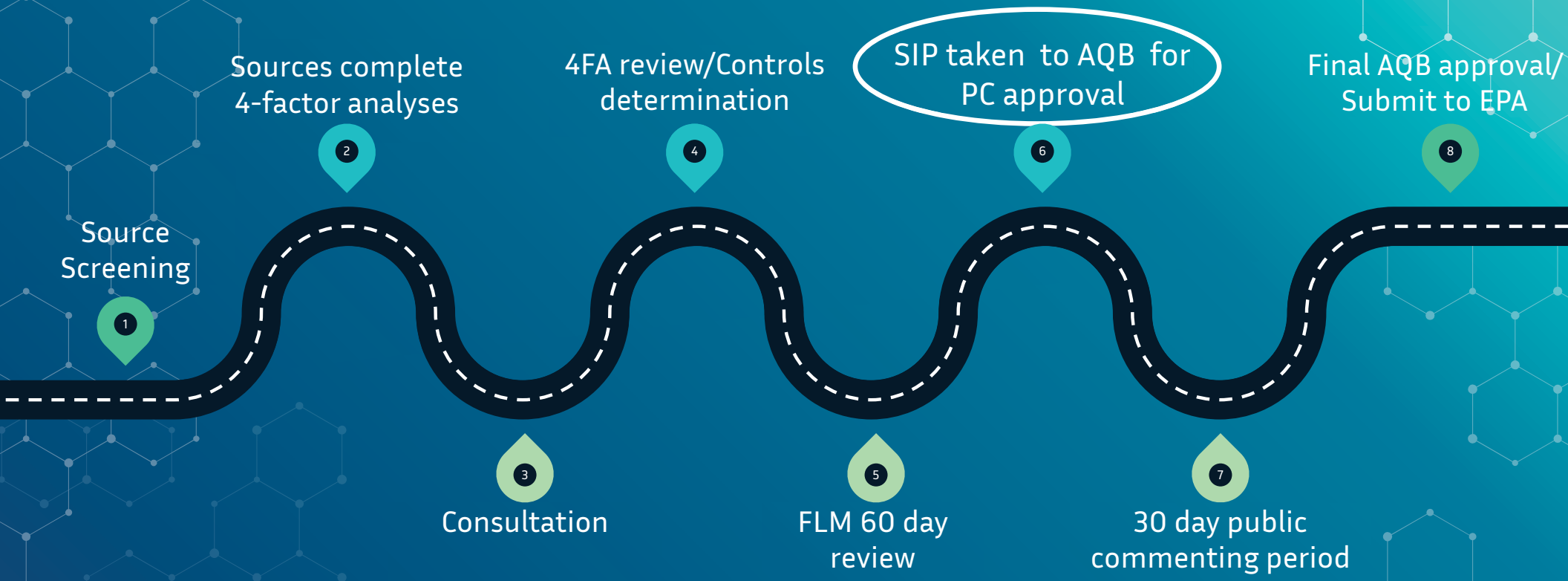
- Physical controls
  - Require all technically feasible, cost-effective controls
- Control cost threshold
- Tighten emissions limits for CCI Paradox and Graymont
- Statewide oil and gas rules
- Additional information for USM and CCI Paradox

US Forest Service Comments

- Emissions reductions have resulted in improvements in visibility.
- Determinations for this planning period will result in visibility improvements better than the URP through 2028.
- Requests UDAQ includes their Rx fire emissions projections in glidepaths.


Adjustments to Uniform Rate of Progress Glidepath - Most Impaired Days
Deciview - Bryce Canyon NP (BRCA1)
Deciview
10.00
8.00
6.00
4.00
2.00
0.00
2000
2010
2020
2030
2040
2050
2060
8.4
6
2064
Uniform Rate of Progress Glidepath: 4.1 DV
A = International: 5.9 DV
B = International + Wildland Rx Fire: 6.2 DV
MID Annual Avg Obs Trendline
Annual Avg Obs - MID
2000-2004 Avg Obs - MID
Uniform Rate of Progress Glidepath
A = International
B = International + Wildland Rx Fire
2028OTBa2 EPA w/o Fire Projection - MID

Round 2 Roadmap



Staff Recommendations

- Propose for Comment:
  - State Implementation Plan Section XX:A: Regional Haze Second Implementation Period
  - Section IX Part H Emission Limits, and
  - Sections 17 and 28 of R307-110 General Requirements: State Implementation Plan

Thank You!

ITEM 6

Air Toxics

State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQA-040-22

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: February 7, 2022

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – January 2022

Asbestos Demolition/Renovation NESHAP Inspections	20
Asbestos AHERA Inspections	18
Asbestos State Rules Only Inspections	0
Asbestos Notification Forms Accepted	106
Asbestos Telephone Calls	315
Asbestos Individuals Certifications Approved	58
Asbestos Company Certifications/Re-Certifications	3/9
Asbestos Alternate Work Practices Approved	1
Lead-Based Paint (LBP) Inspections	0
LBP Notification Forms Approved	1
LBP Telephone Calls	58
LBP Letters Prepared and Mailed	0
LBP Courses Reviewed/Approved	0
LBP Course Audits	0
LBP Individual Certifications Approved	10

LBP Firm Certifications	8
Notices of Violation Sent	0
Compliance Advisories Sent	7
Warning Letters Sent	1
Settlement Agreements Finalized	0
Penalties Agreed to:	

State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQA-084-22

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: March 9, 2022

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – February 2022

Asbestos Demolition/Renovation NESHAP Inspections	14
Asbestos AHERA Inspections	12
Asbestos State Rules Only Inspections	2
Asbestos Notification Forms Accepted	108
Asbestos Telephone Calls	349
Asbestos Individuals Certifications Approved	75
Asbestos Company Certifications/Re-Certifications	0/7
Asbestos Alternate Work Practices Approved	0
Lead-Based Paint (LBP) Inspections	1
LBP Notification Forms Approved	1
LBP Telephone Calls	45
LBP Letters Prepared and Mailed	3
LBP Courses Reviewed/Approved	0
LBP Course Audits	0
LBP Individual Certifications Approved	31

LBP Firm Certifications	11
Notices of Violation Sent	0
Compliance Advisories Sent	6
Warning Letters Sent	4
Settlement Agreements Finalized	0
Penalties Agreed to:	

Compliance

State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQC-191-22

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: February 8, 2022

SUBJECT: Compliance Activities – January 2022

ACTIVITIES:

Activity	Monthly Total	36-Month Average
Inspections	49	52
On-Site Stack Test & CEM Audits	2	3
Stack Test & RATA Report Reviews	37	31
Emission Report Reviews	24	13
Temporary Relocation Request Reviews	7	7
Fugitive Dust Control Plan Reviews	151	144
Soil Remediation Report Reviews	2	2
Open Burn Permits Issued	0	132
Miscellaneous Inspections[1]	16	21
Complaints Received	20	13
Wood Burning Complaints Received	6	0
Breakdown Reports Received	0	1
Compliance Actions Resulting from a Breakdown	0	0
VOC Inspections	0	0
Warning Letters Issued	0	1
Notices of Violation Issued	0	0
Compliance Advisories Issued	10	5
No Further Action Letters Issued	1	2
Settlement Agreements Reached	2	2
Penalties Assessed	$10,471.00	$27,234.88

[1]Miscellaneous inspections include, e.g., surveillance, complaint, on-site training, dust patrol, smoke patrol, open burning, etc.

SETTLEMENT AGREEMENTS:

Party	Amount
Wolverine Gas and Oil	$471.00
Big West Oil	$10,000.00

UNRESOLVED NOTICES OF VIOLATION:

Party	Date Issued
US Magnesium (in litigation)	08/27/2015
US Magnesium (in litigation)	03/02/2018
Crescent Point	07/24/2020
CH4 Finley	07/24/2020
Ovintiv	07/14/2020
EP Energy	03/20/2020
Paradox Resources/Four Corners Pipeline (tolled)	11/05/2021
US Magnesium (hearing requested)	11/16/2021

State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQC-365-22

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: March 15, 2022

SUBJECT: Compliance Activities – February 2022

ACTIVITIES:

Activity	Monthly Total	36-Month Average
Inspections	83	51
On-Site Stack Test & CEM Audits	1	4
Stack Test & RATA Report Reviews	12	32
Emission Report Reviews	24	13
Temporary Relocation Request Reviews	6	7
Fugitive Dust Control Plan Reviews	164	144
Soil Remediation Report Reviews	4	2
Open Burn Permits Issued	0	132
Miscellaneous Inspections[1]	4	20
Complaints Received	37	12
Wood Burning Complaints Received	6	0
Breakdown Reports Received	0	1
Compliance Actions Resulting from a Breakdown	0	0
VOC Inspections	0	0
Warning Letters Issued	0	1
Notices of Violation Issued	0	0
Compliance Advisories Issued	4	5
No Further Action Letters Issued	1	2
Settlement Agreements Reached	2	2
Penalties Assessed	$6,318.00	$27,049.71

[1]Miscellaneous inspections include, e.g., surveillance, complaint, on-site training, dust patrol, smoke patrol, open burning, etc.

195 North 1950 West • Salt Lake City, Utah
Mailing Address: P.O. Box 144820 • Salt Lake City, Utah 84114-4820
Telephone (801) 536-4000 • Fax (801)536-4099 • T.D.D. (801) 536-4284
www.deq.utah.gov

SETTLEMENT AGREEMENTS:

Party	Amount
Iowa Tank Lines	$5,600.00
Mity-Lite	$718.00

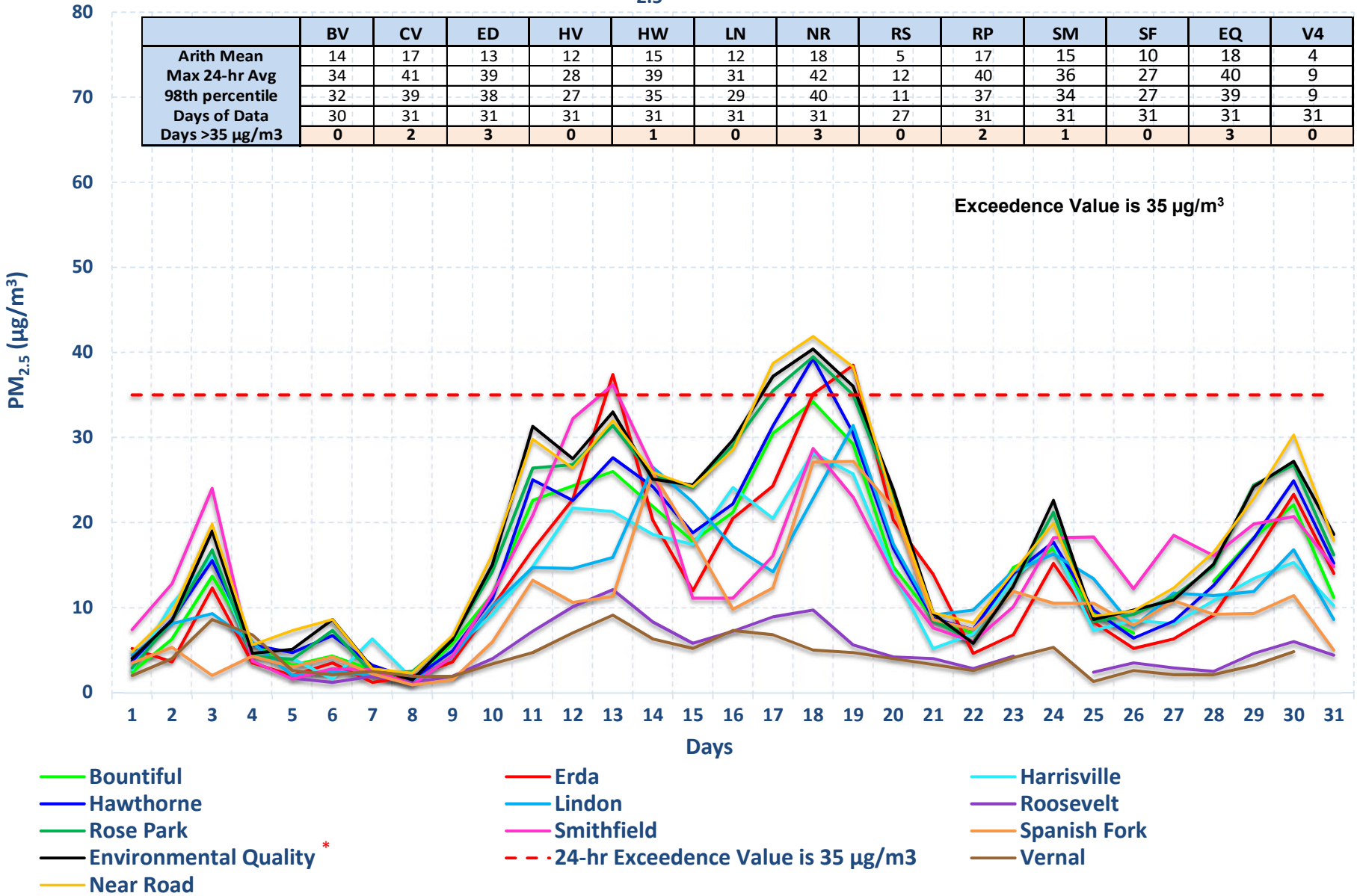
UNRESOLVED NOTICES OF VIOLATION:

Party	Date Issued
US Magnesium (in litigation)	08/27/2015
US Magnesium (in litigation)	03/02/2018
EP Energy	03/20/2020
Crescent Point	07/24/2020
CH4 Finley	07/24/2020
Ovintiv	07/14/2020
Paradox Resources/Four Corners Pipeline (tolled)	11/05/2021
US Magnesium (hearing requested)	11/16/2021

Air Monitoring

Utah 24-Hr $PM_{2.5}$ Data Jan 2022

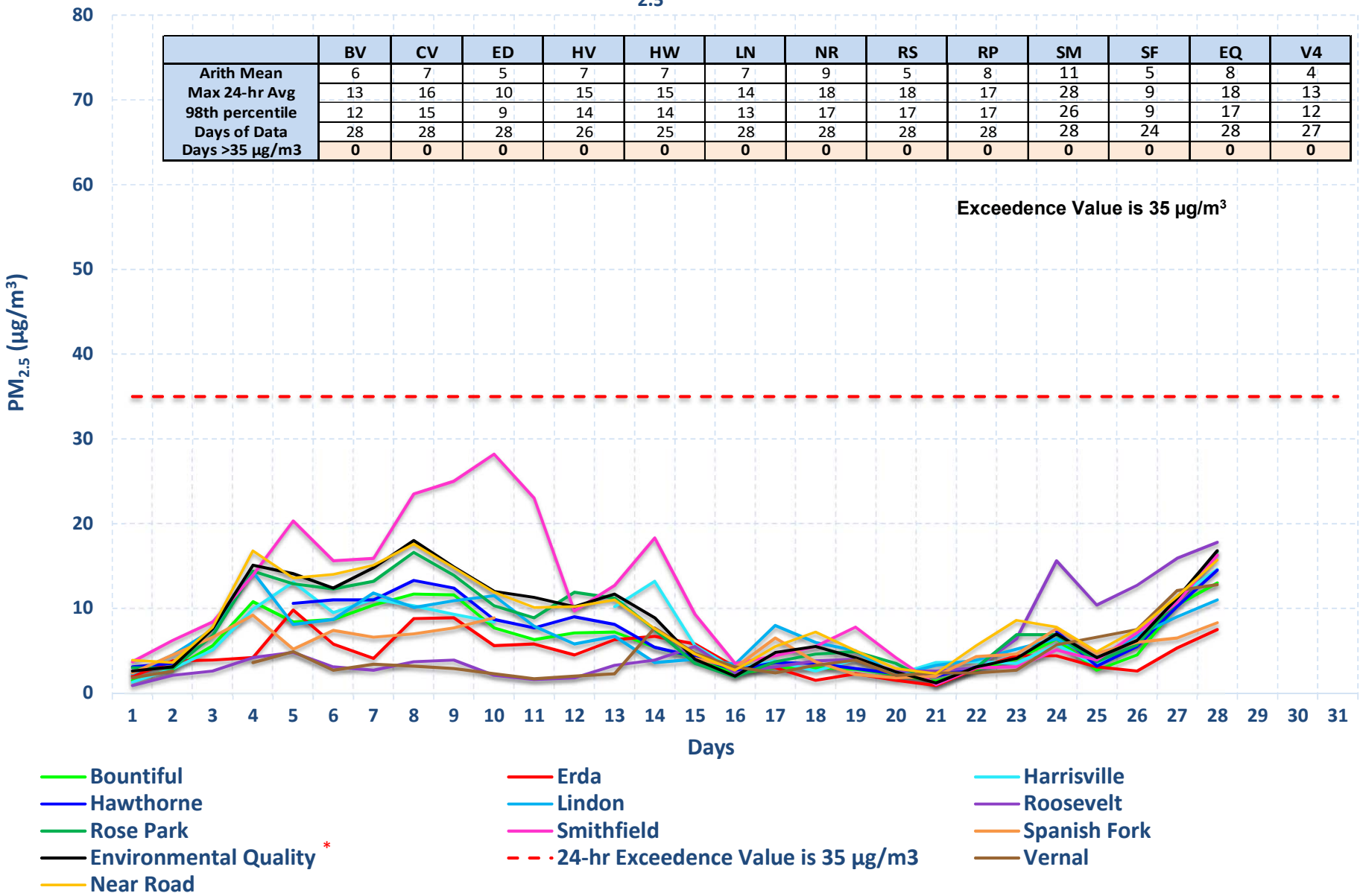
	BV	CV	ED	HV	HW	LN	NR	RS	RP	SM	SF	EQ	V4
Arith Mean	14	17	13	12	15	12	18	5	17	15	10	18	4
Max 24-hr Avg	34	41	39	28	39	31	42	12	40	36	27	40	9
98th percentile	32	39	38	27	35	29	40	11	37	34	27	39	9
Days of Data	30	31	31	31	31	31	31	27	31	31	31	31	31
Days >35 µg/m3	**0**	**2**	**3**	**0**	**1**	**0**	**3**	**0**	**2**	**1**	**0**	**3**	**0**



* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)

Utah 24-Hr $PM_{2.5}$ Data Feb 2022

	BV	CV	ED	HV	HW	LN	NR	RS	RP	SM	SF	EQ	V4
Arith Mean	6	7	5	7	7	7	9	5	8	11	5	8	4
Max 24-hr Avg	13	16	10	15	15	14	18	18	17	28	9	18	13
98th percentile	12	15	9	14	14	13	17	17	17	26	9	17	12
Days of Data	28	28	28	26	25	28	28	28	28	28	24	28	27
Days >35 µg/m3	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

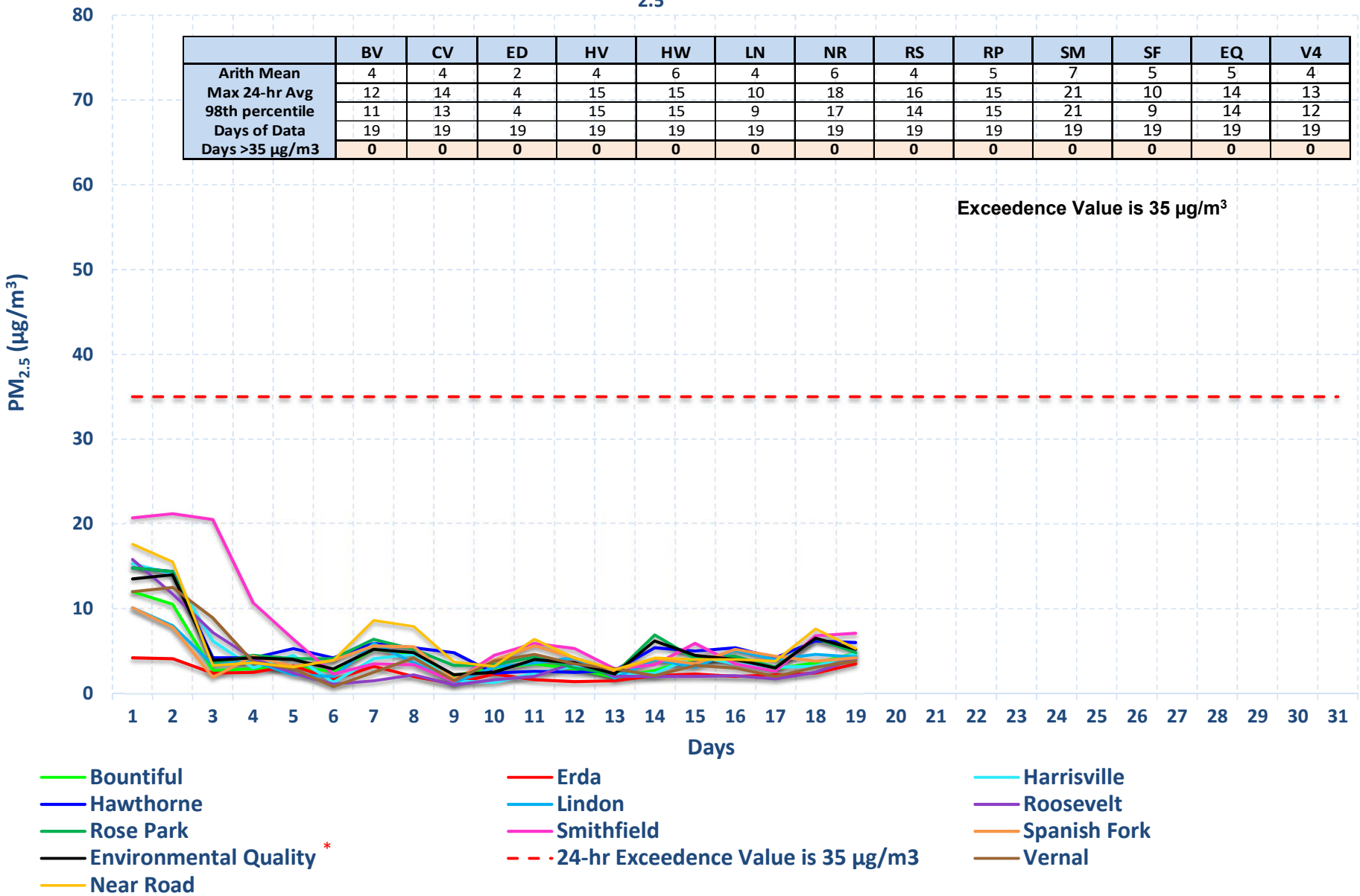


* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)

Utah Division of Air Quality

Utah 24-Hr $PM_{2.5}$ Data March 2022

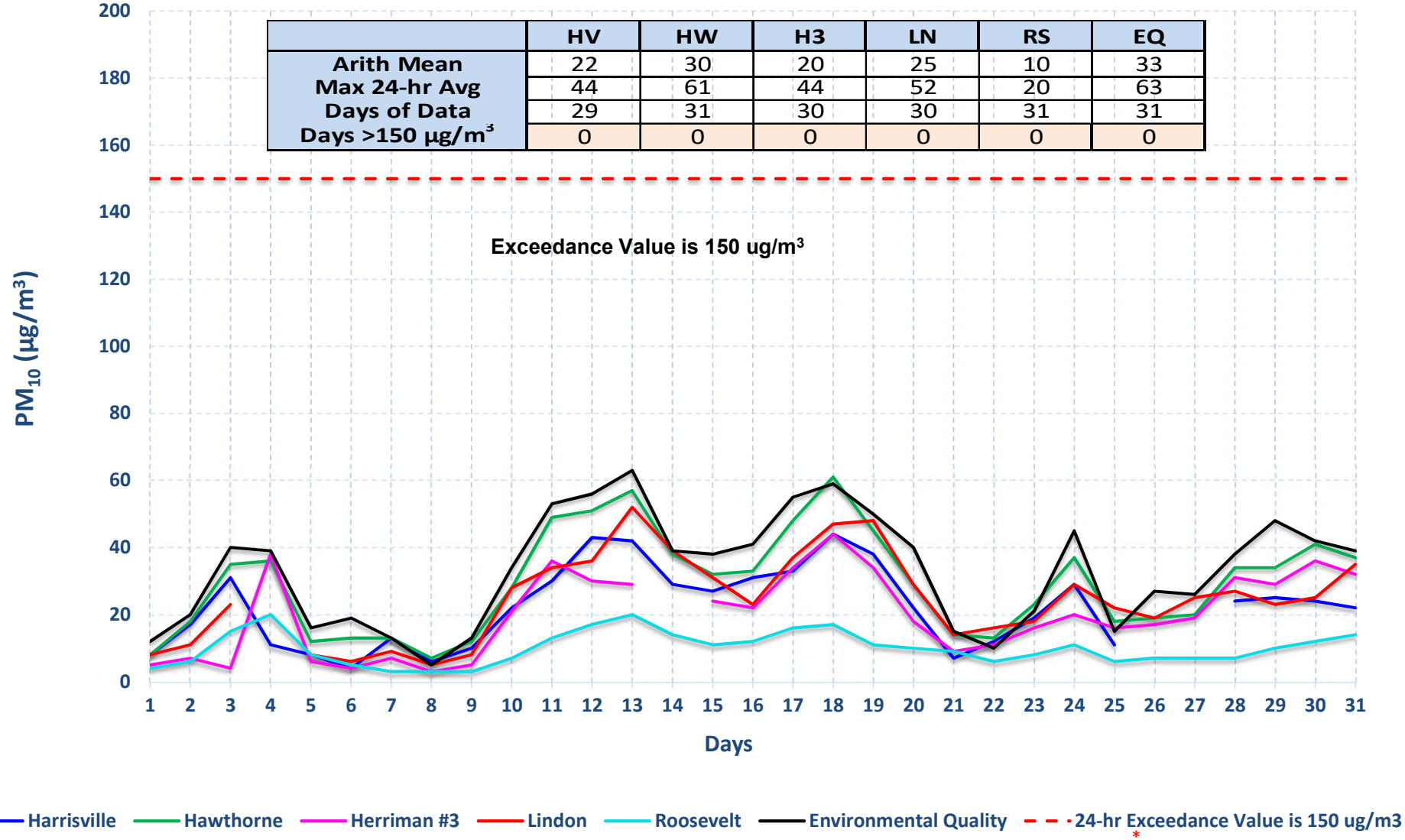
	BV	CV	ED	HV	HW	LN	NR	RS	RP	SM	SF	EQ	V4
Arith Mean	4	4	2	4	6	4	6	4	5	7	5	5	4
Max 24-hr Avg	12	14	4	15	15	10	18	16	15	21	10	14	13
98th percentile	11	13	4	15	15	9	17	14	15	21	9	14	12
Days of Data	19	19	19	19	19	19	19	19	19	19	19	19	19
Days >35 µg/m3	0	0	0	0	0	0	0	0	0	0	0	0	0



* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)

Utah 24-hr PM_{10} Data Jan 2022

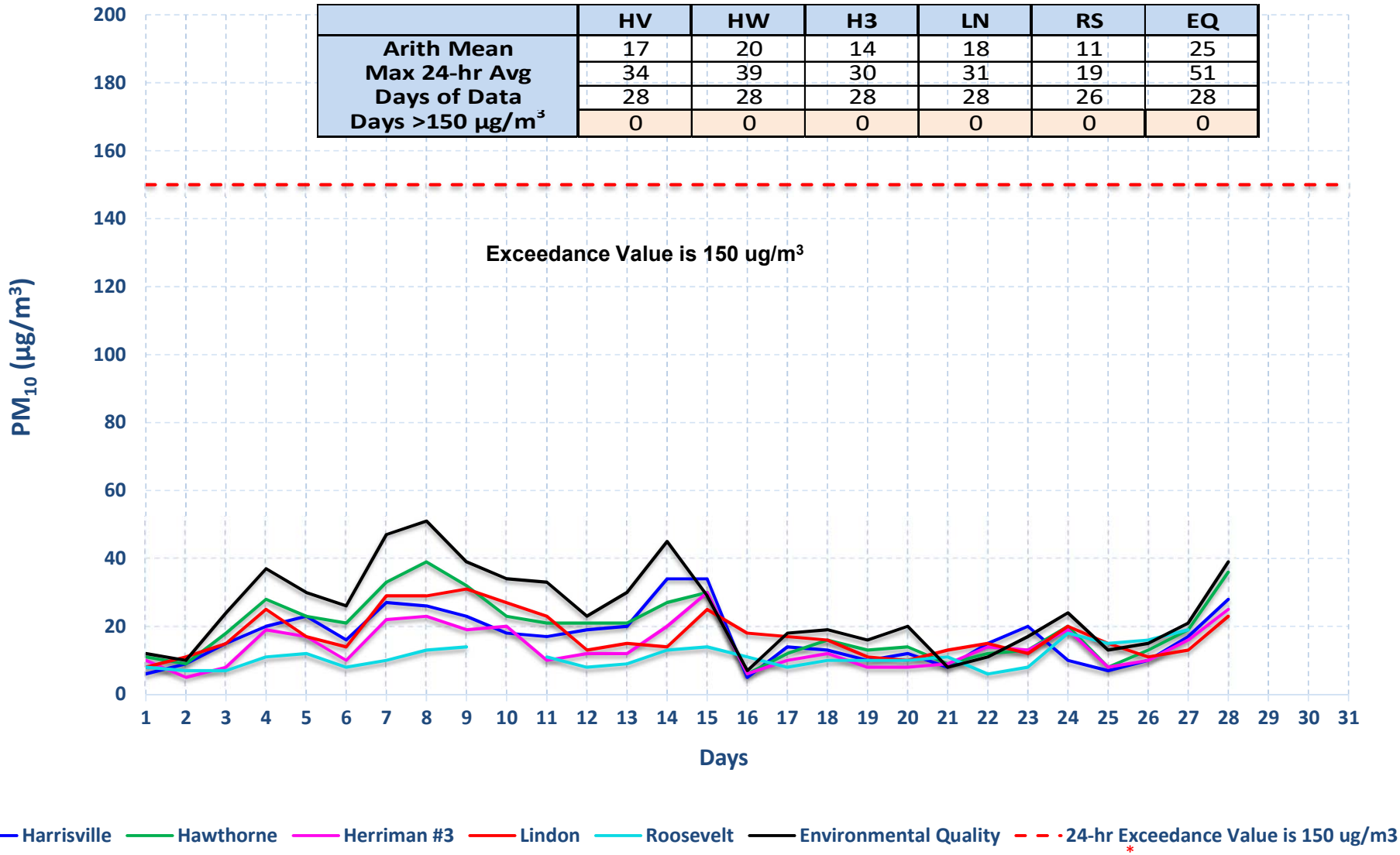
	HV	HW	H3	LN	RS	EQ
Arith Mean	22	30	20	25	10	33
Max 24-hr Avg	44	61	44	52	20	63
Days of Data	29	31	30	30	31	31
Days >150 µg/m³	0	0	0	0	0	0



* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)

Utah 24-hr PM_{10} Data Feb 2022

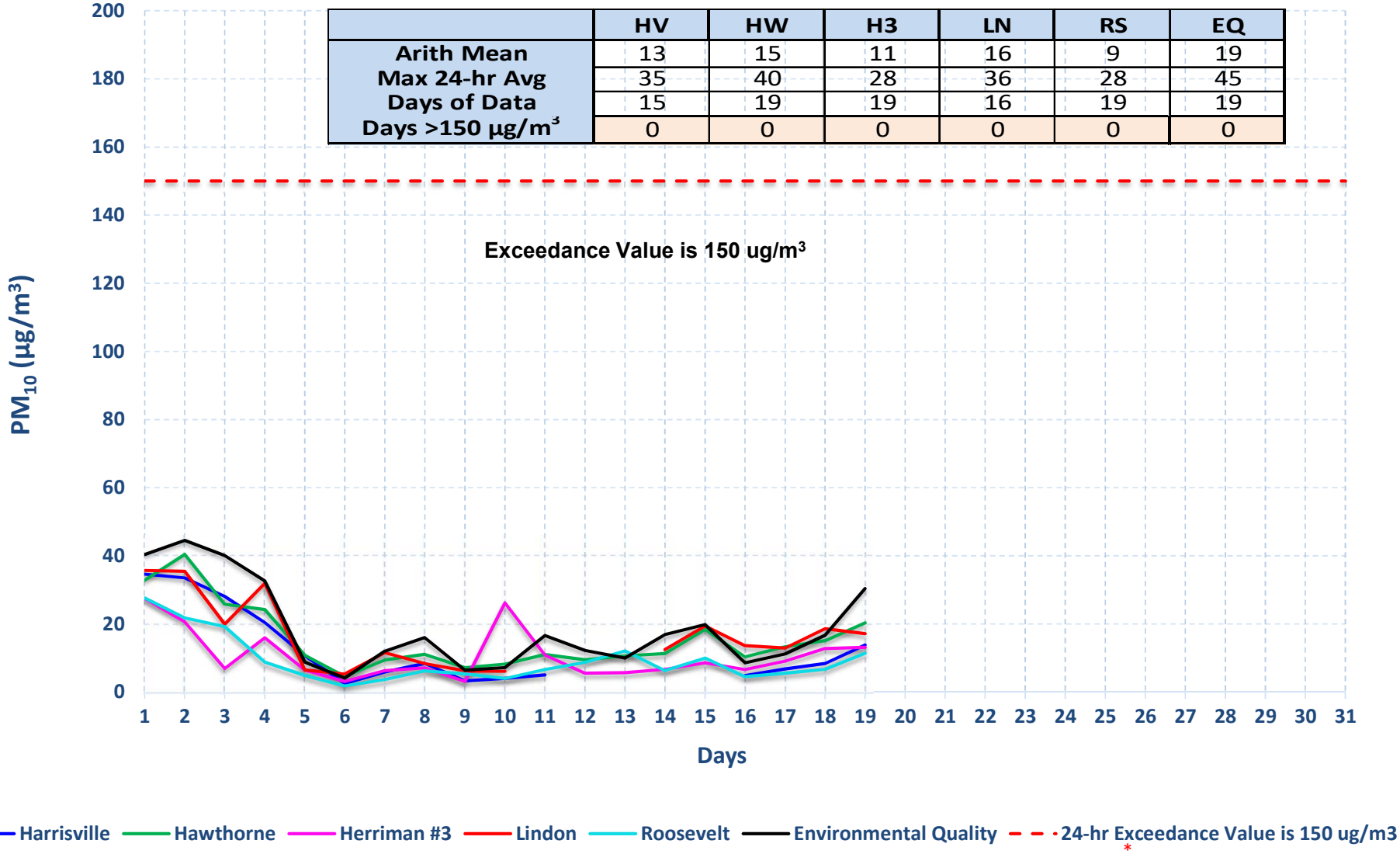
	HV	HW	H3	LN	RS	EQ
Arith Mean	17	20	14	18	11	25
Max 24-hr Avg	34	39	30	31	19	51
Days of Data	28	28	28	28	26	28
Days >150 µg/m³	0	0	0	0	0	0



* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)

Utah 24-hr PM_{10} Data Mar 2022

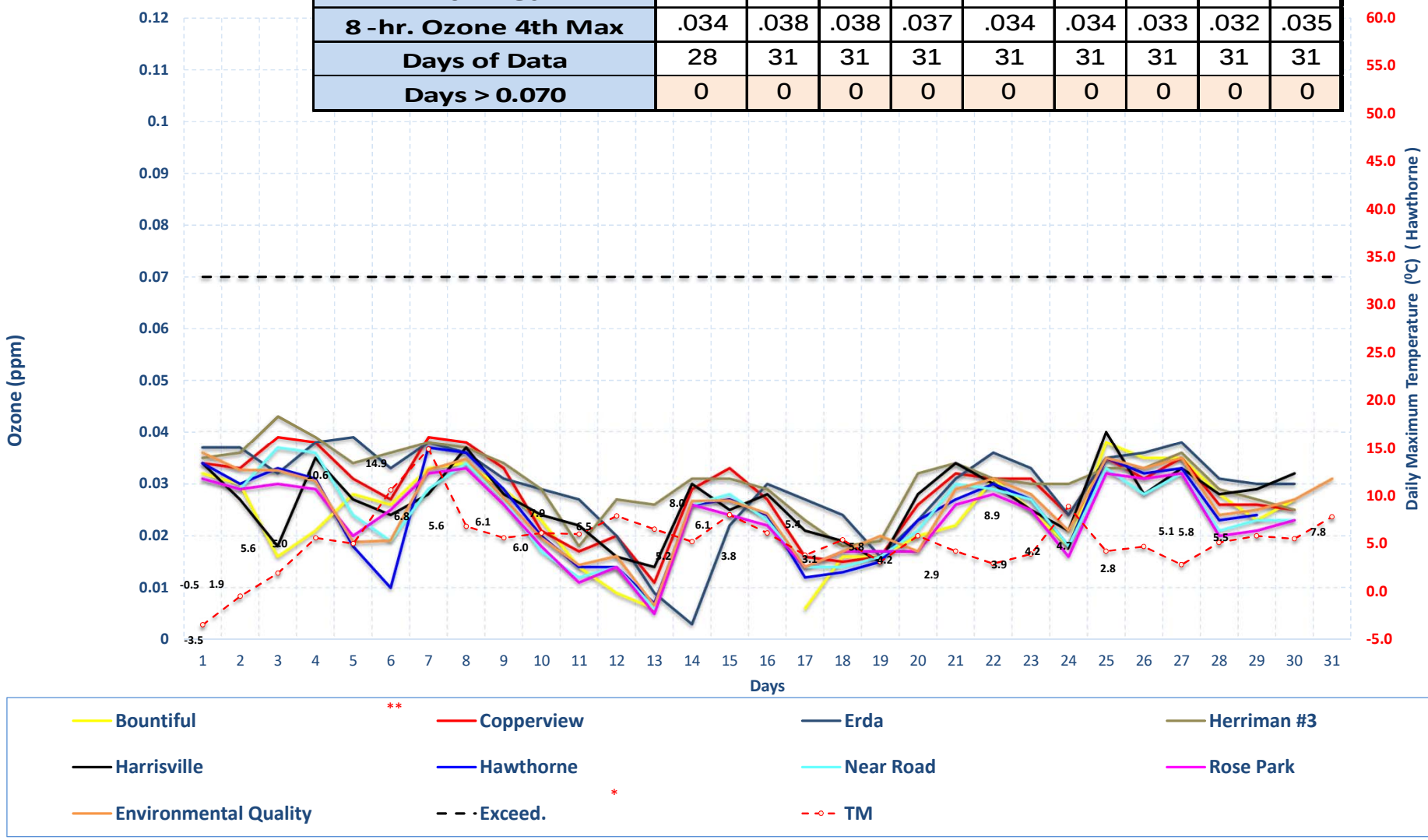
	HV	HW	H3	LN	RS	EQ
Arith Mean	13	15	11	16	9	19
Max 24-hr Avg	35	40	28	36	28	45
Days of Data	15	19	19	16	19	19
Days >150 µg/m³	0	0	0	0	0	0



* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)

Highest 8-hr Ozone Concentration & Daily Maximum Temperature Jan 2022

	BV	CV	ED	H3	HV	HW	NR	RP	EQ
Arith Mean	.024	.028	.029	.031	.027	.024	.024	.023	.025
8 -hr. Ozone 4th Max	.034	.038	.038	.037	.034	.034	.033	.032	.035
Days of Data	28	31	31	31	31	31	31	31	31
Days > 0.070	0	0	0	0	0	0	0	0	0

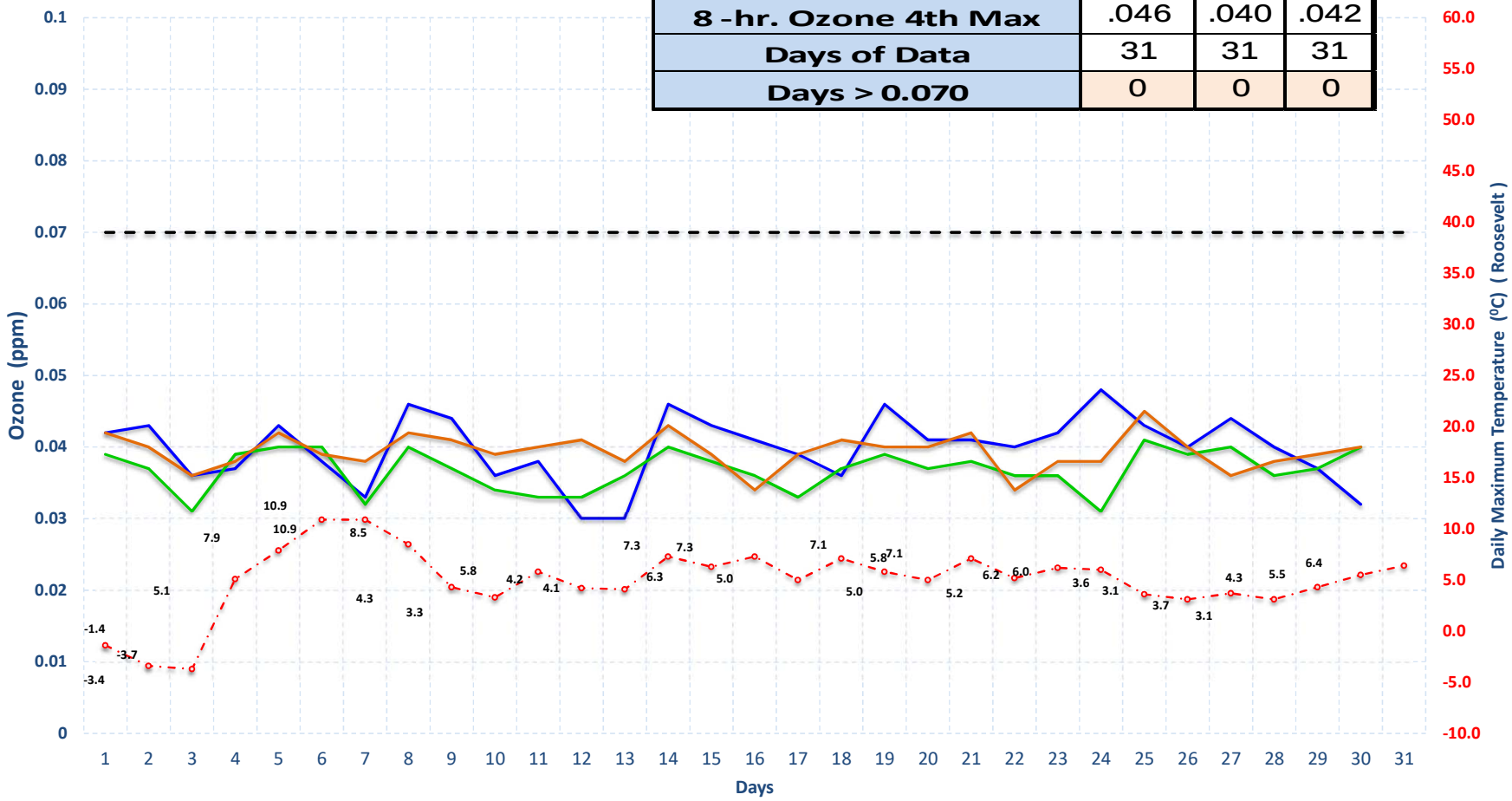


* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)

** Controlling Monitor

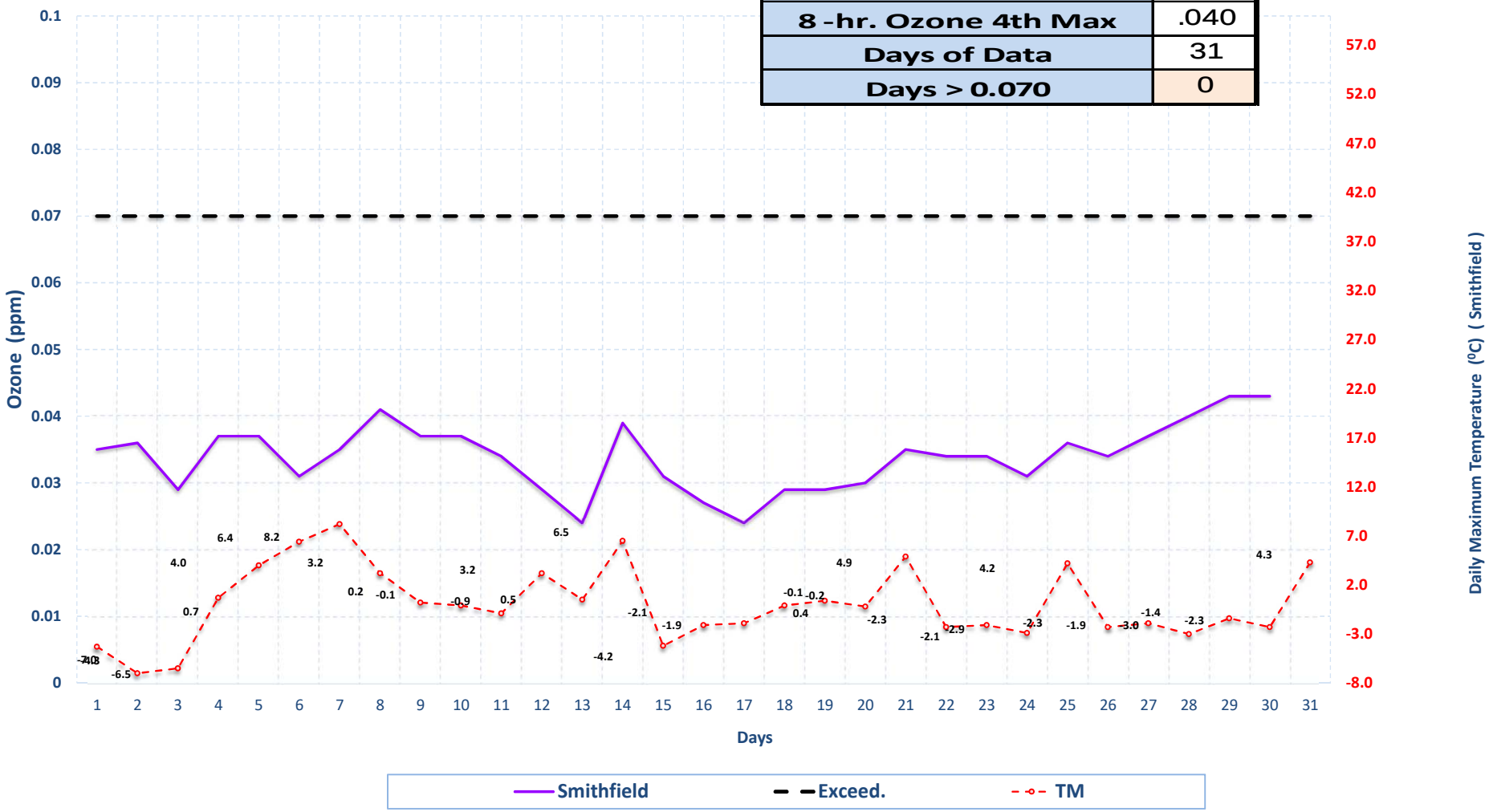
Highest 8-hr Ozone Concentration & Daily Maximum Temperature Jan 2022

	P2	RS	V4
Arith Mean	.040	.037	.039
8 -hr. Ozone 4th Max	.046	.040	.042
Days of Data	31	31	31
Days > 0.070	0	0	0



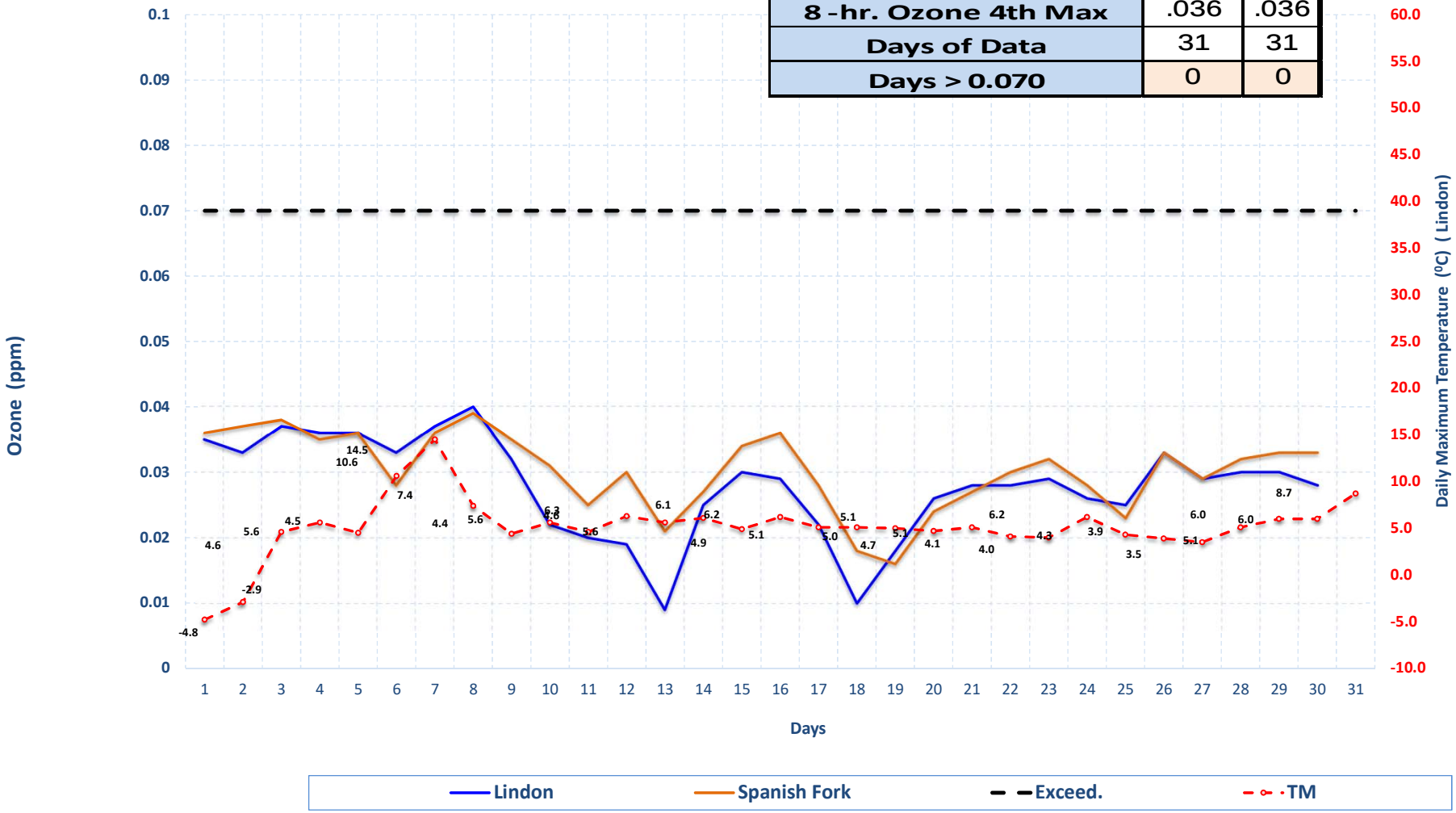
Highest 8-hr Ozone Concentration & Daily Maximum Temperature Jan 2022

	SM
Arith Mean	.034
8 -hr. Ozone 4th Max	.040
Days of Data	31
Days > 0.070	0



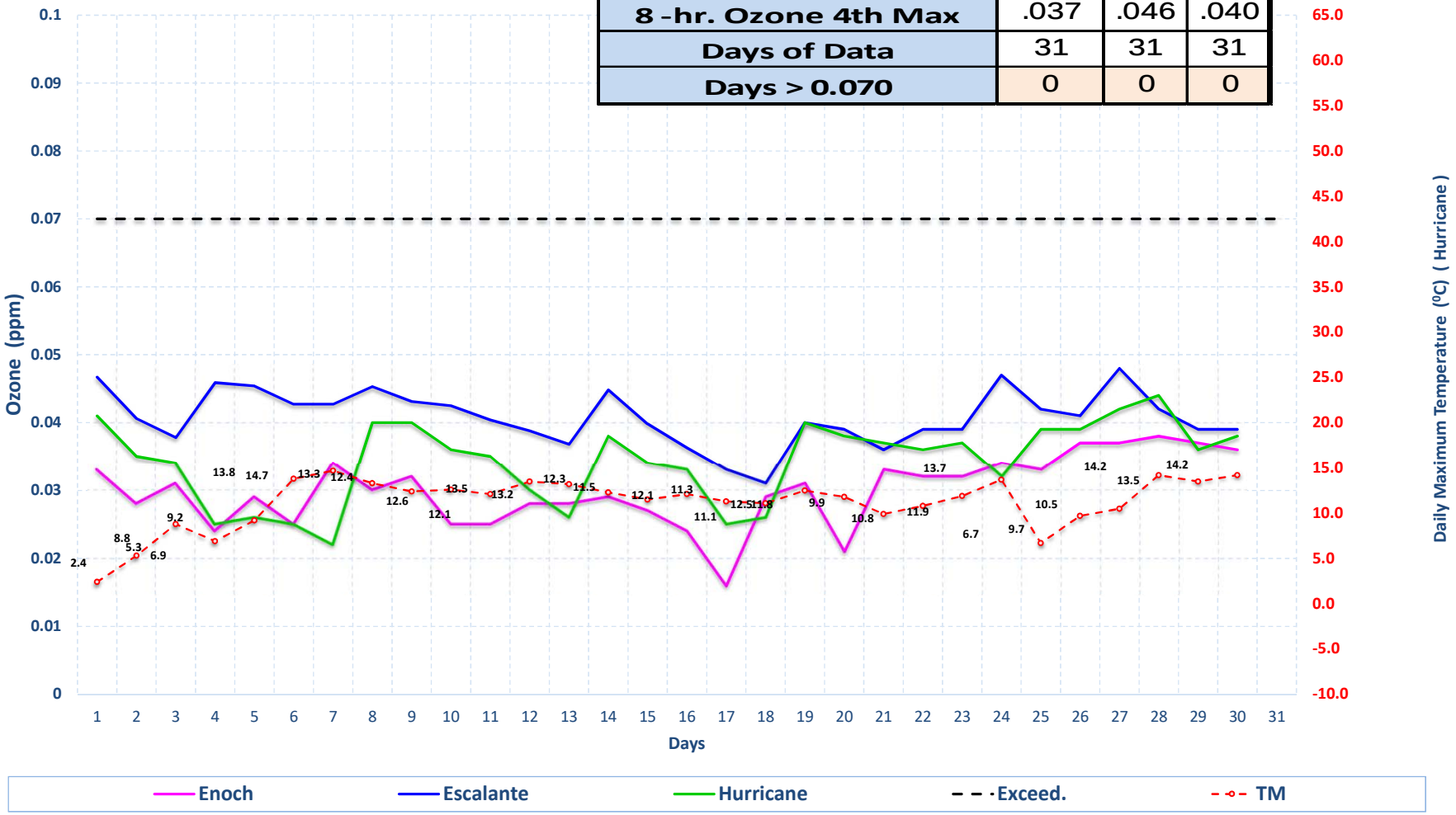
Highest 8-hr Ozone Concentration & Daily Maximum Temperature Jan 2022

	LN	SF
Arith Mean	.028	.030
8 -hr. Ozone 4th Max	.036	.036
Days of Data	31	31
Days > 0.070	0	0



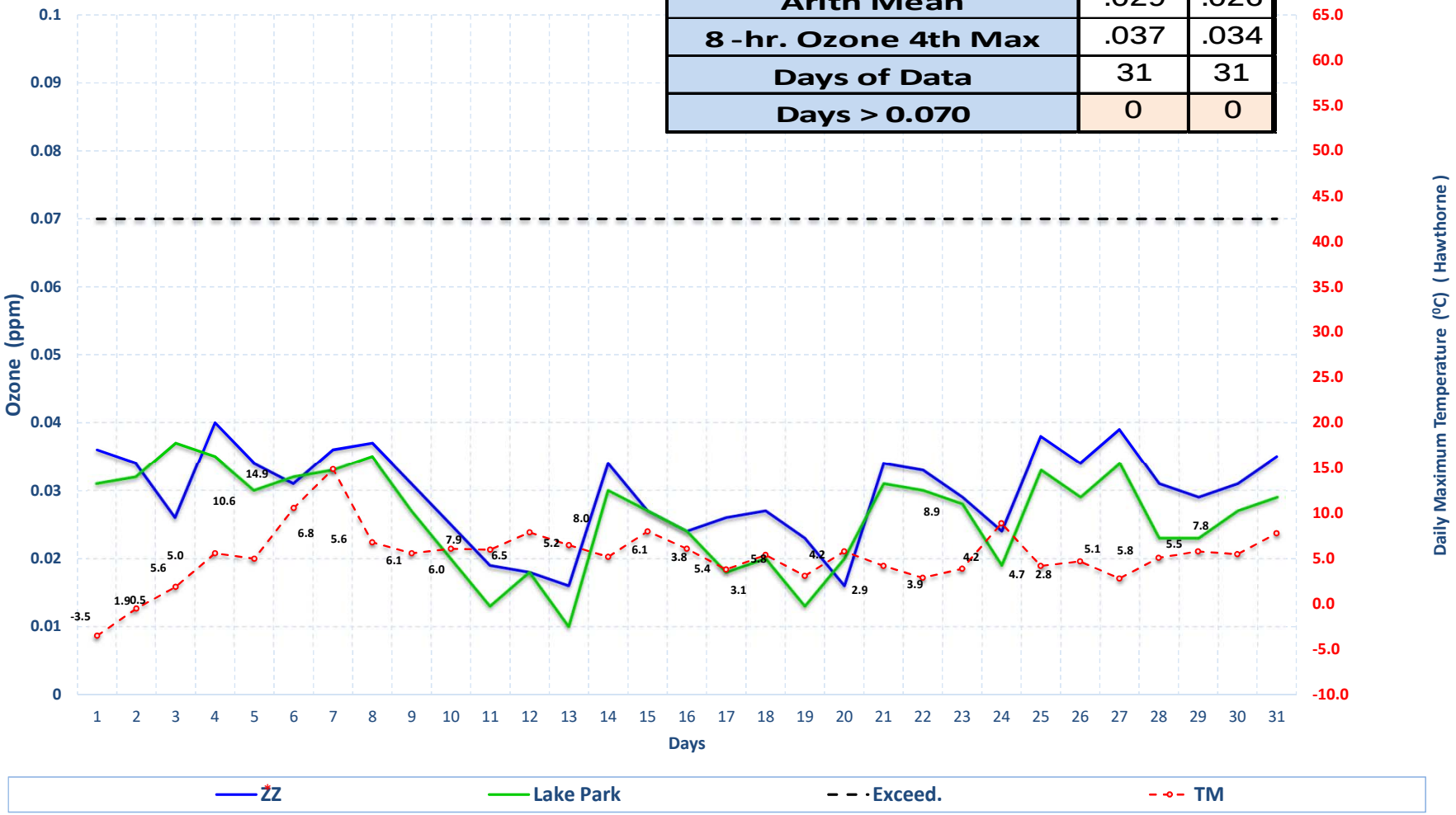
Highest 8-hr Ozone Concentration & Daily Maximum Temperature Jan 2022

	EN	ES	HC
Arith Mean	.030	.041	.034
8 -hr. Ozone 4th Max	.037	.046	.040
Days of Data	31	31	31
Days > 0.070	0	0	0



Highest 8-hr Ozone Concentration & Daily Maximum Temperature Jan 2022
Stations monitoring the Inland Port development

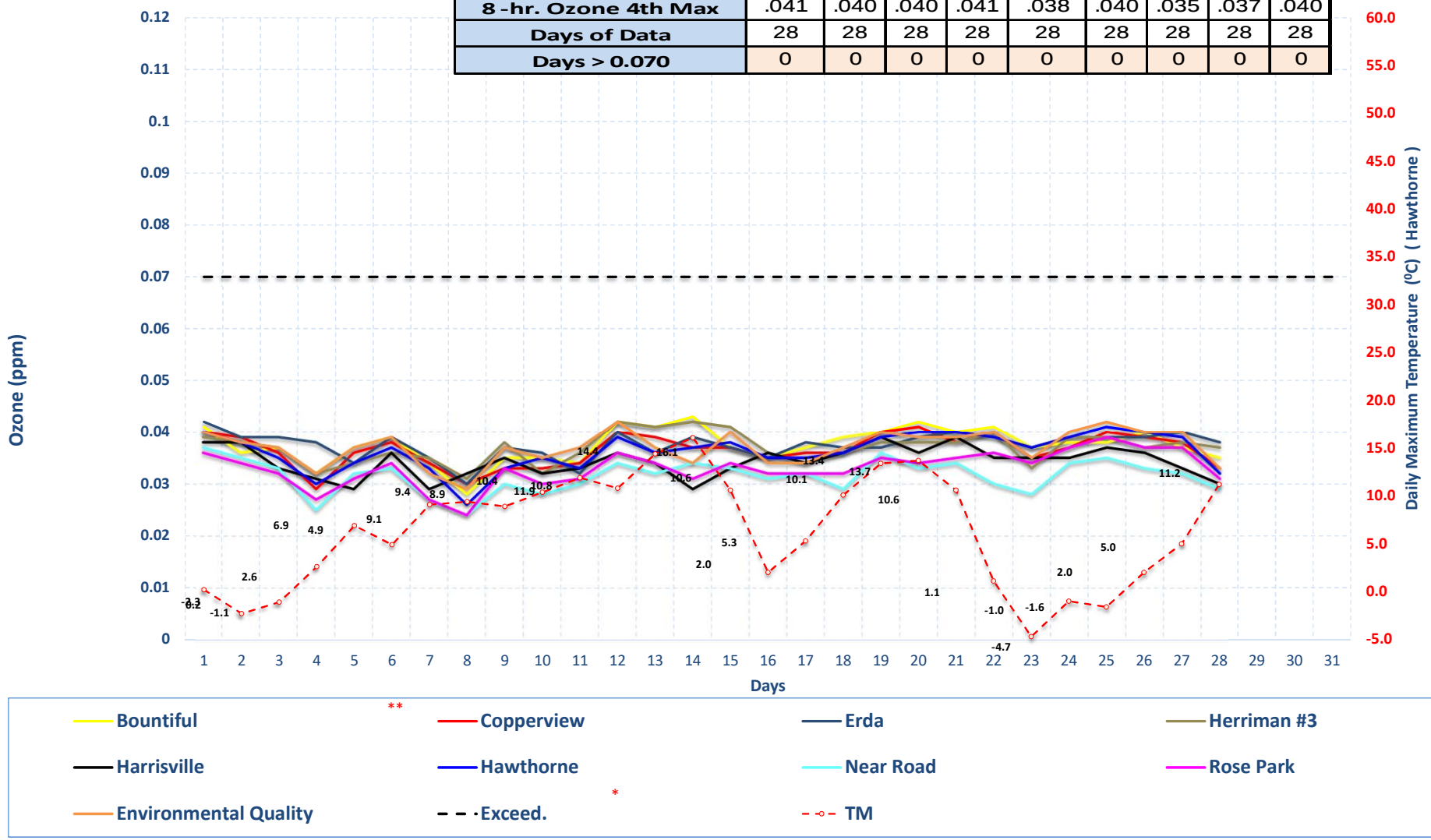
	ZZ	LP
Arith Mean	.029	.026
8 -hr. Ozone 4th Max	.037	.034
Days of Data	31	31
Days > 0.070	0	0



* **ZZ** is located at the New Utah State Prison (1480 North 8000 West, SLC).
This site was previously named **IP**

Highest 8-hr Ozone Concentration & Daily Maximum Temperature Feb 2022

	BV	CV	ED	H3	HV	HW	NR	RP	EQ
Arith Mean	.038	.037	.038	.037	.034	.036	.032	.033	.037
8 -hr. Ozone 4th Max	.041	.040	.040	.041	.038	.040	.035	.037	.040
Days of Data	28	28	28	28	28	28	28	28	28
Days > 0.070	0	0	0	0	0	0	0	0	0

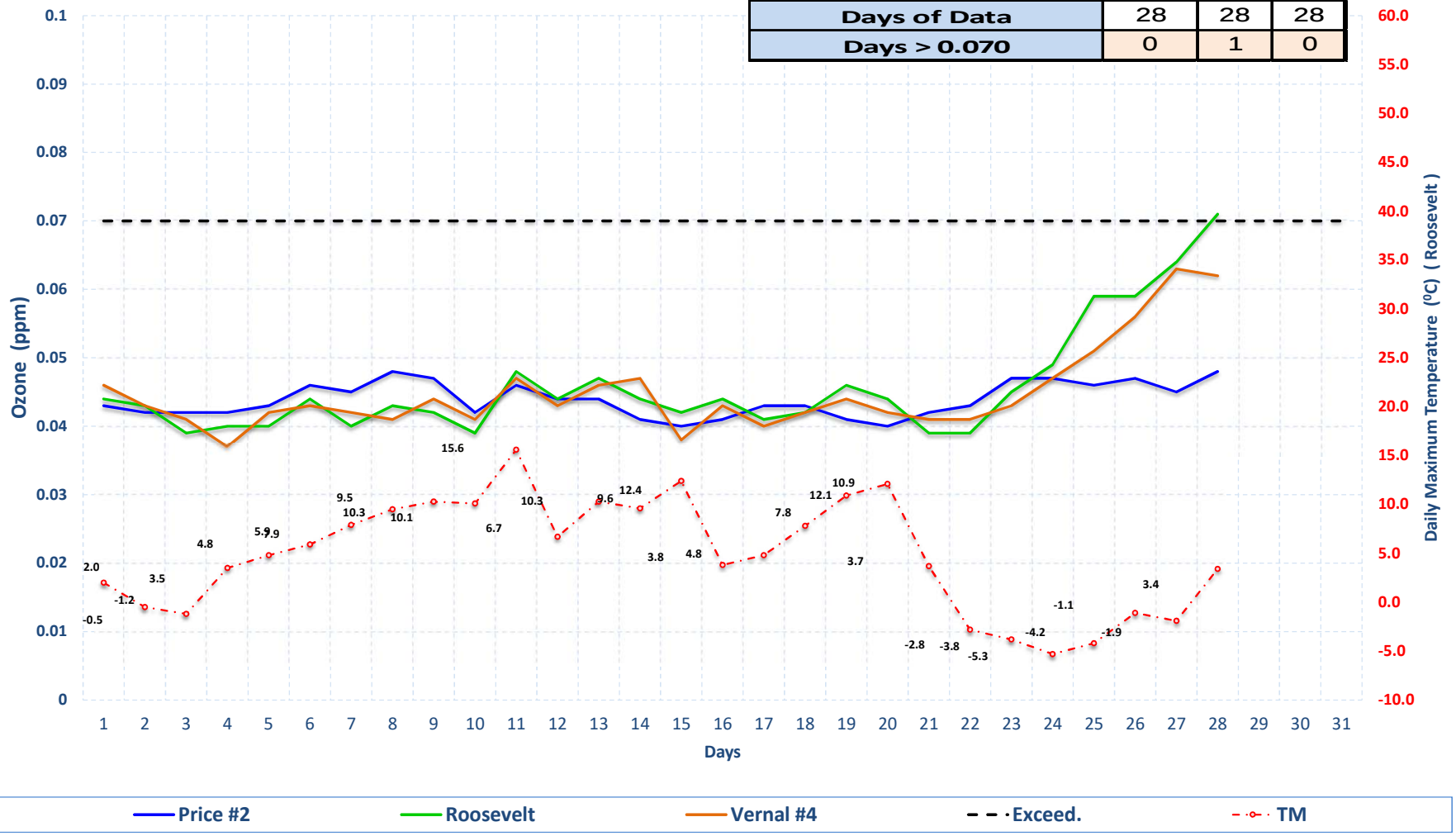


* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)

** Controlling Monitor

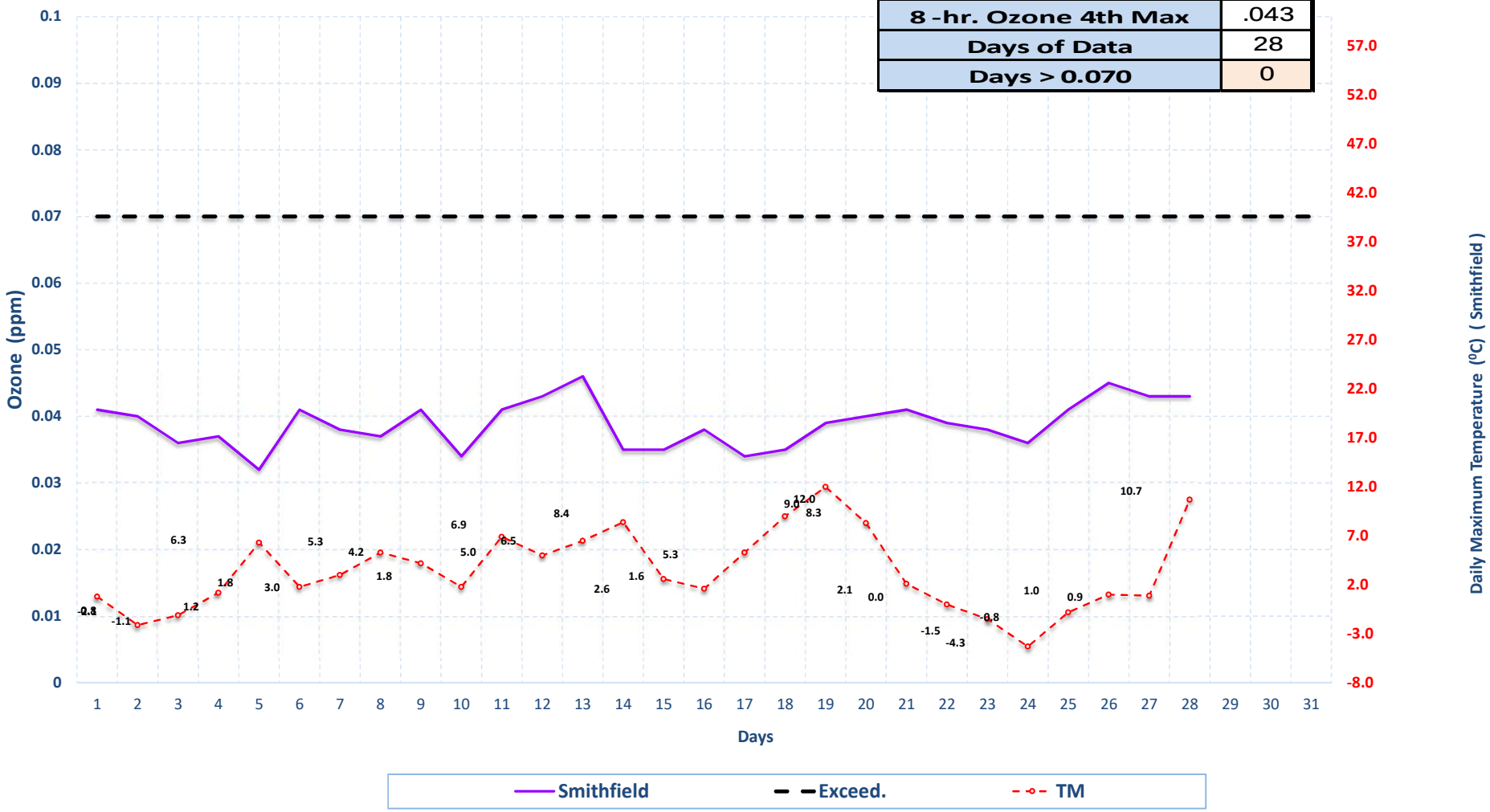
Highest 8-hr Ozone Concentration & Daily Maximum Temperature Feb 2022

	P2	RS	V4
Arith Mean	.044	.046	.045
8 -hr. Ozone 4th Max	.047	.059	.051
Days of Data	28	28	28
Days > 0.070	0	1	0



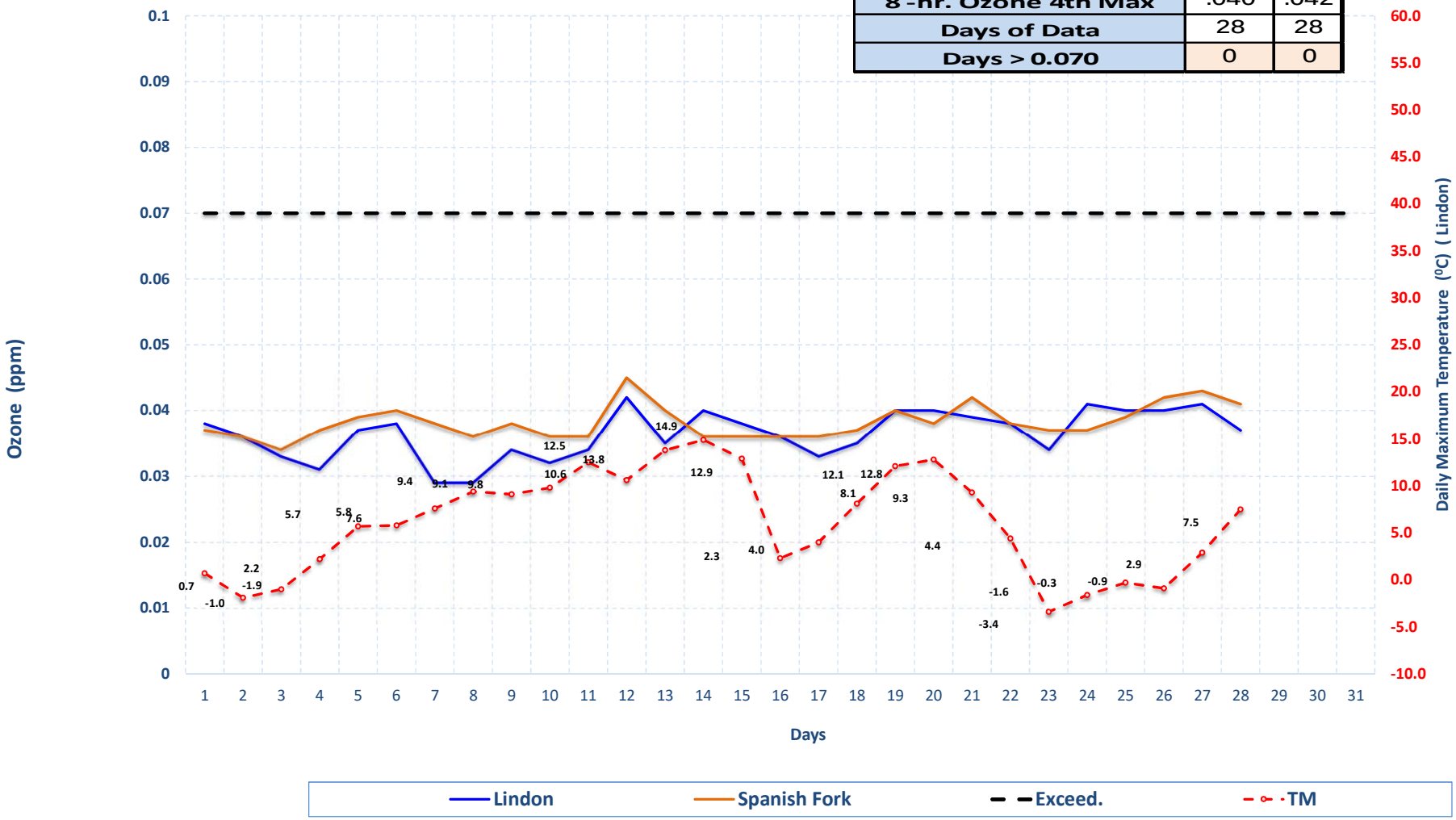
Highest 8-hr Ozone Concentration & Daily Maximum Temperature Feb 2022

	SM
Arith Mean	.039
8 -hr. Ozone 4th Max	.043
Days of Data	28
Days > 0.070	0



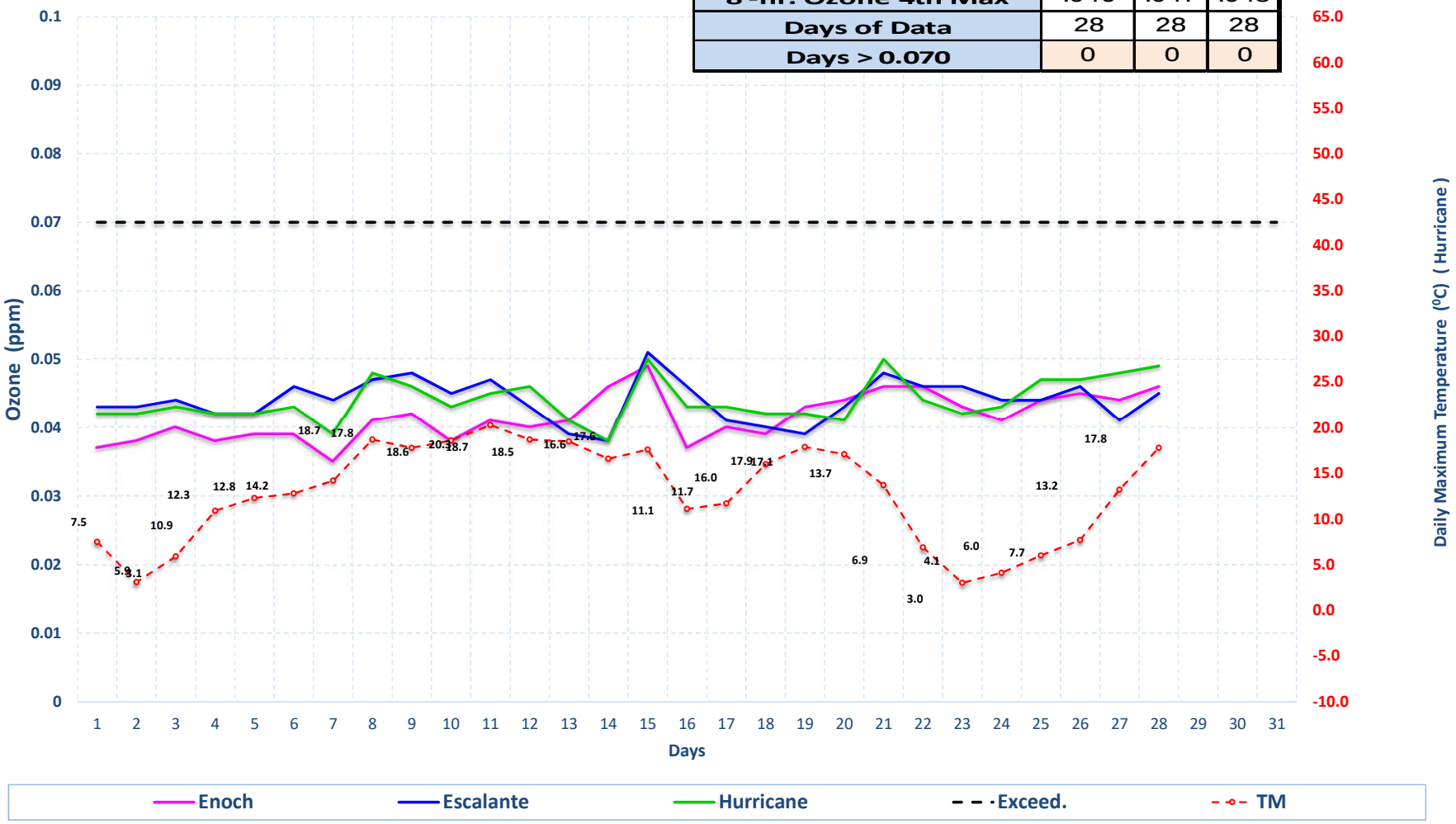
Highest 8-hr Ozone Concentration & Daily Maximum Temperature Feb 2022

	LN	SF
Arith Mean	.036	.038
8 -hr. Ozone 4th Max	.040	.042
Days of Data	28	28
Days > 0.070	0	0



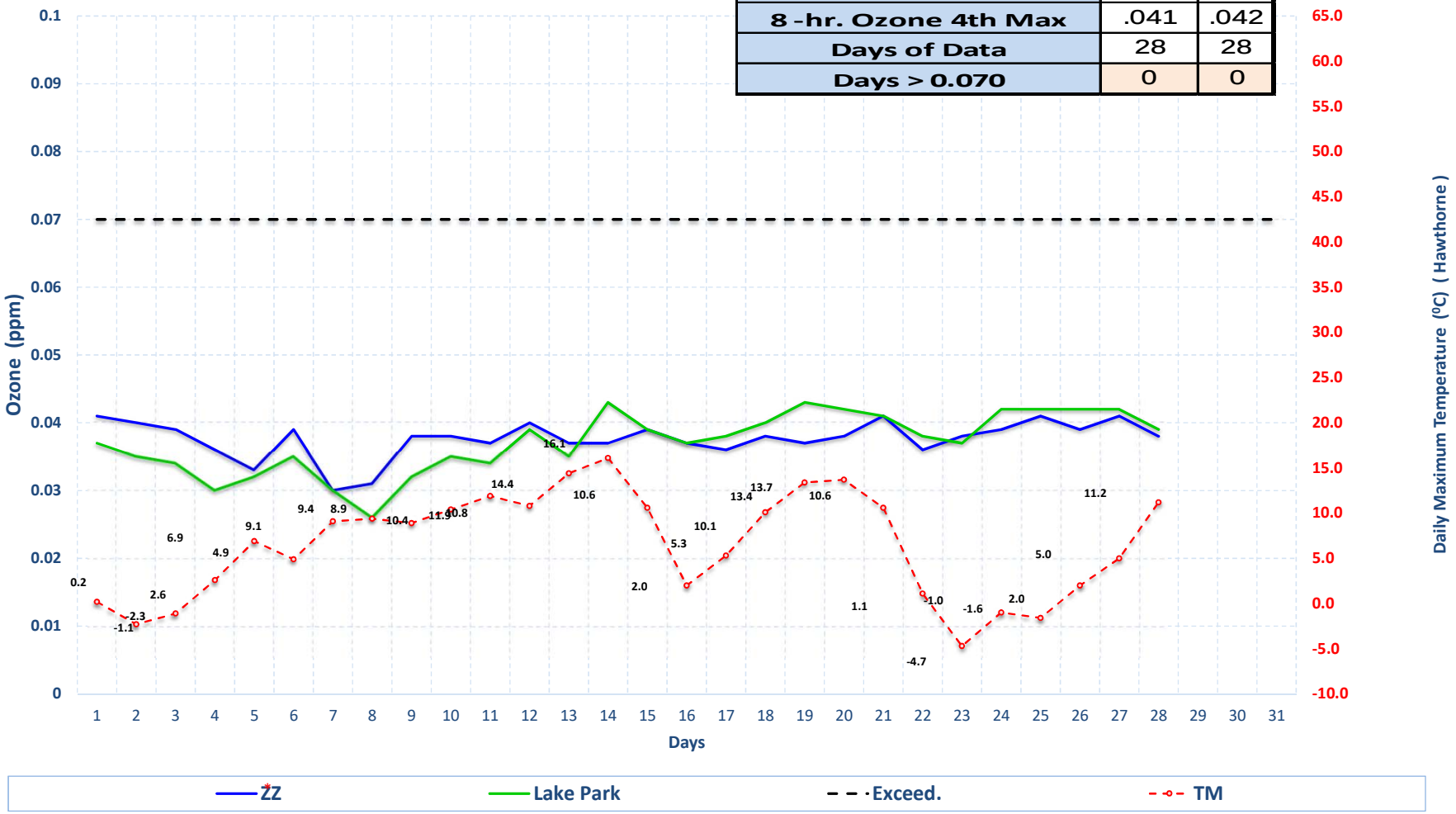
Highest 8-hr Ozone Concentration & Daily Maximum Temperature Feb 2022

	EN	ES	HC
Arith Mean	.042	.044	.044
8 -hr. Ozone 4th Max	.046	.047	.048
Days of Data	28	28	28
Days > 0.070	0	0	0



Highest 8-hr Ozone Concentration & Daily Maximum Temperature Feb 2022
Stations monitoring the Inland Port development

	ZZ	LP
Arith Mean	.038	.037
8 -hr. Ozone 4th Max	.041	.042
Days of Data	28	28
Days > 0.070	0	0



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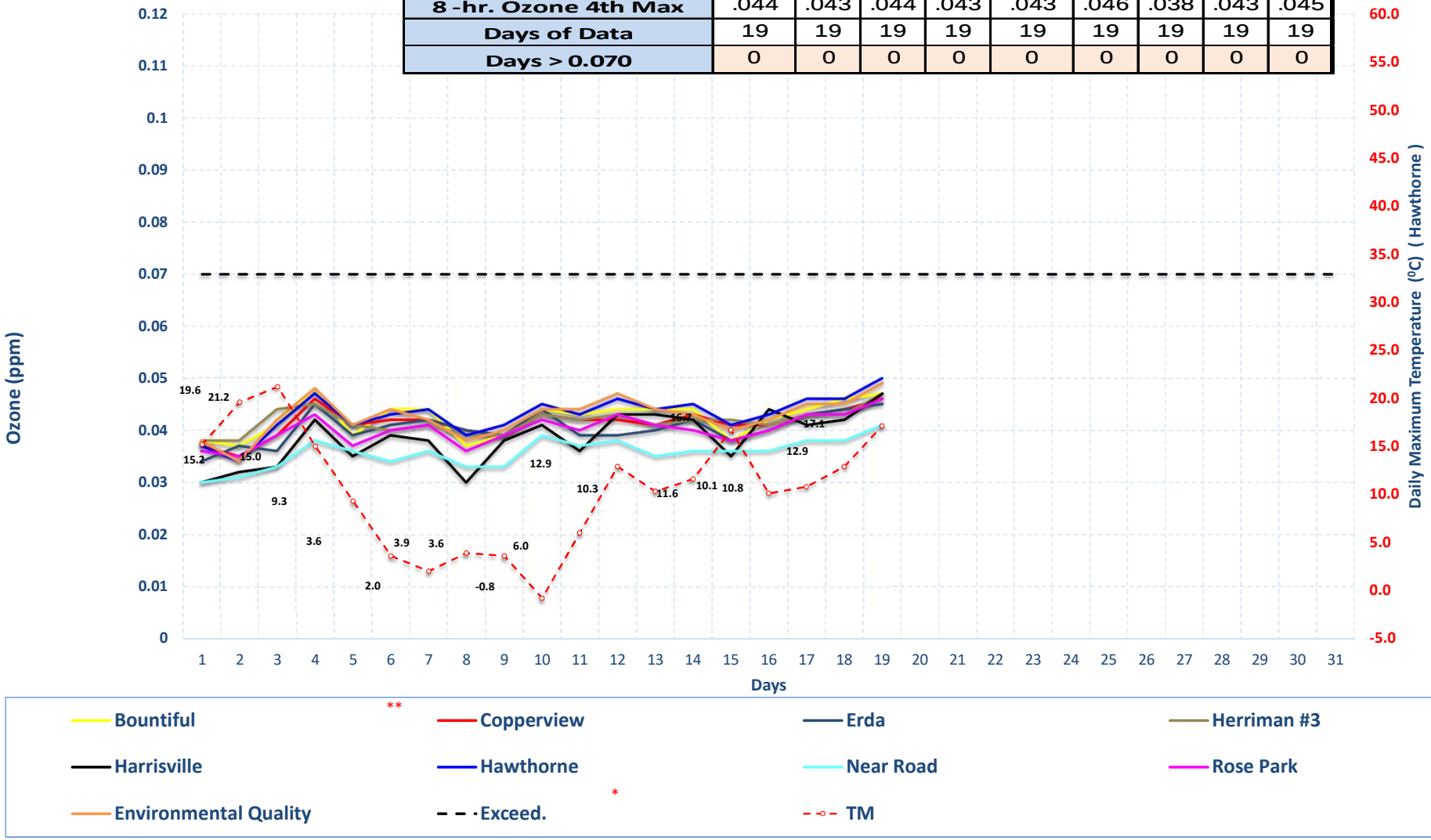
This site was previously named **IP**

Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2022

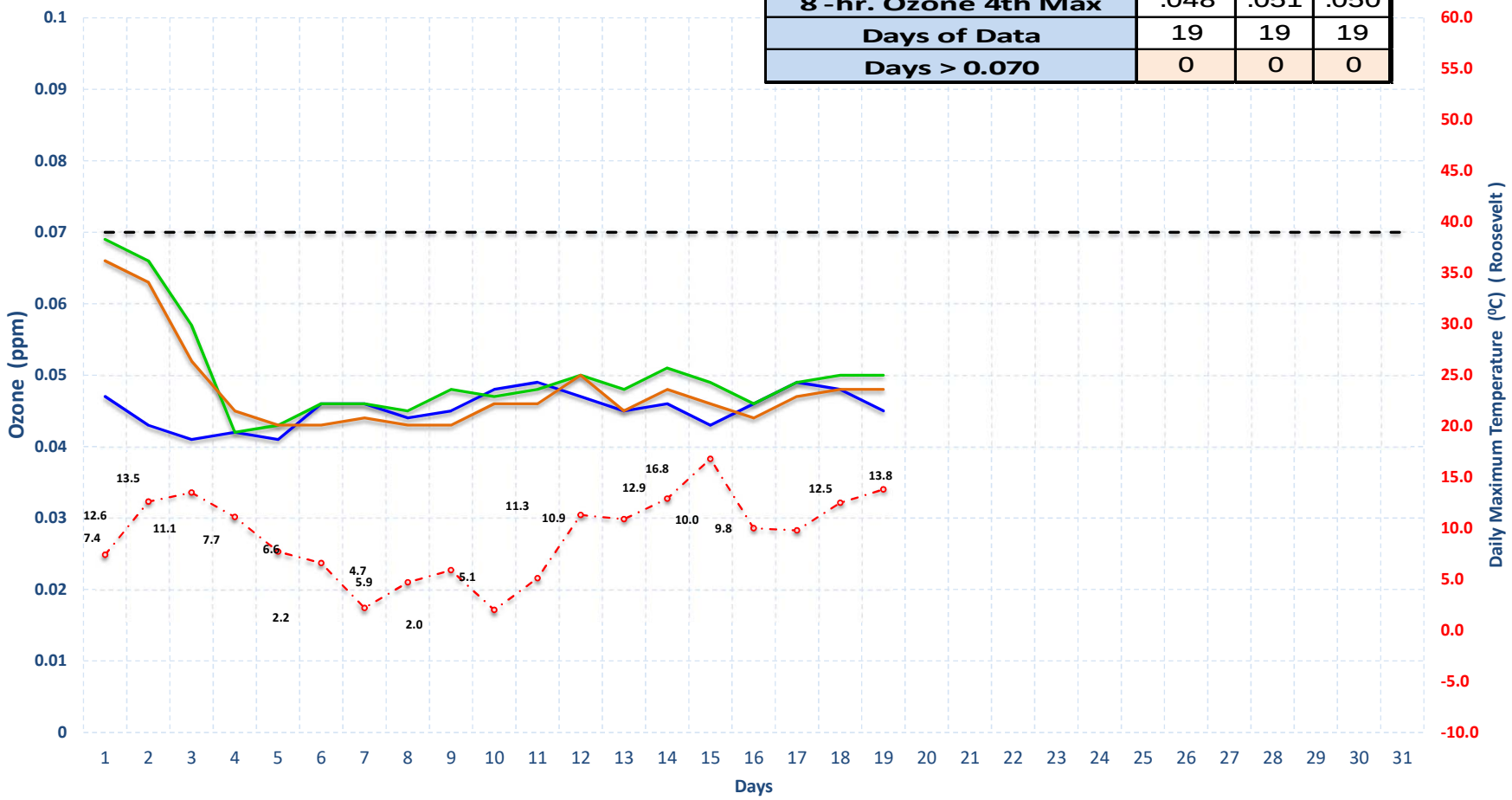
	BV	CV	ED	H3	HV	HW	NR	RP	EQ
Arith Mean	.042	.041	.040	.042	.038	.043	.036	.040	.043
8 -hr. Ozone 4th Max	.044	.043	.044	.043	.043	.046	.038	.043	.045
Days of Data	19	19	19	19	19	19	19	19	19
Days > 0.070	0	0	0	0	0	0	0	0	0



* Environmental Quality (**EQ**) previously named Technical Support Center (**TSC**)
** Controlling Monitor

Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2022

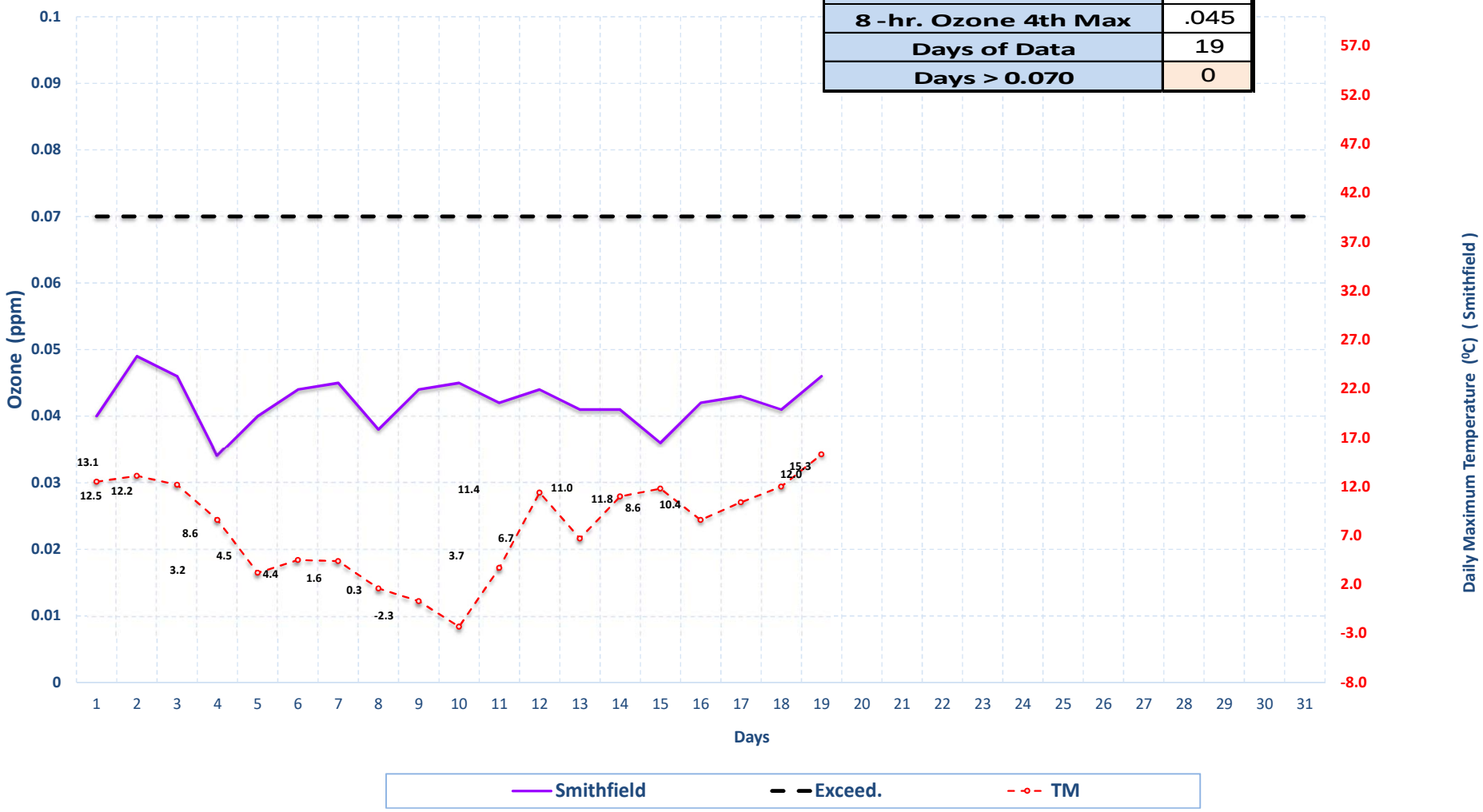
	P2	RS	V4
Arith Mean	.045	.050	.048
8 -hr. Ozone 4th Max	.048	.051	.050
Days of Data	19	19	19
Days > 0.070	0	0	0



Price #2 | Roosevelt | Vernal #4 | Exceed. | TM

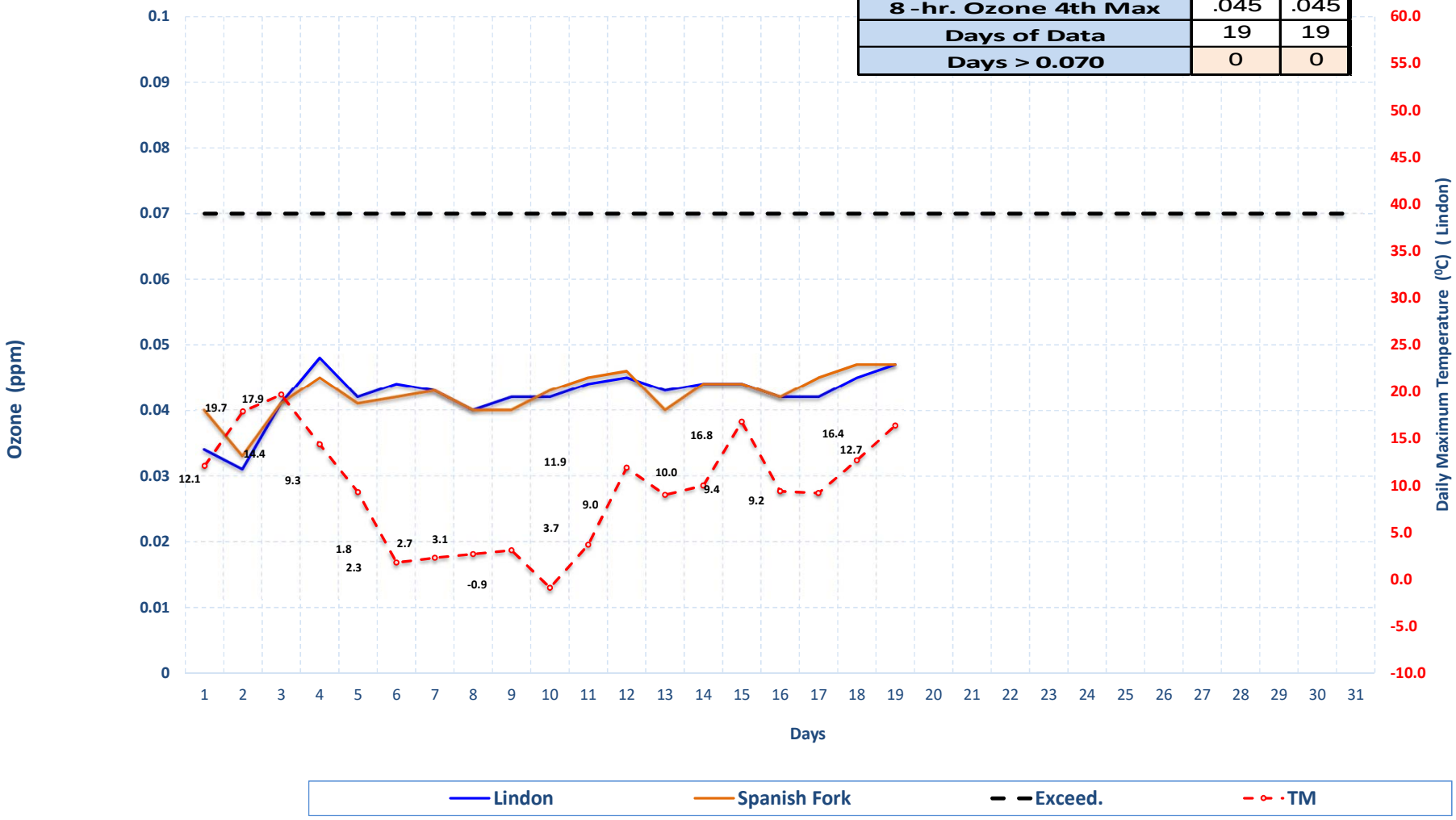
Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2022

	SM
Arith Mean	.042
8 -hr. Ozone 4th Max	.045
Days of Data	19
Days > 0.070	0



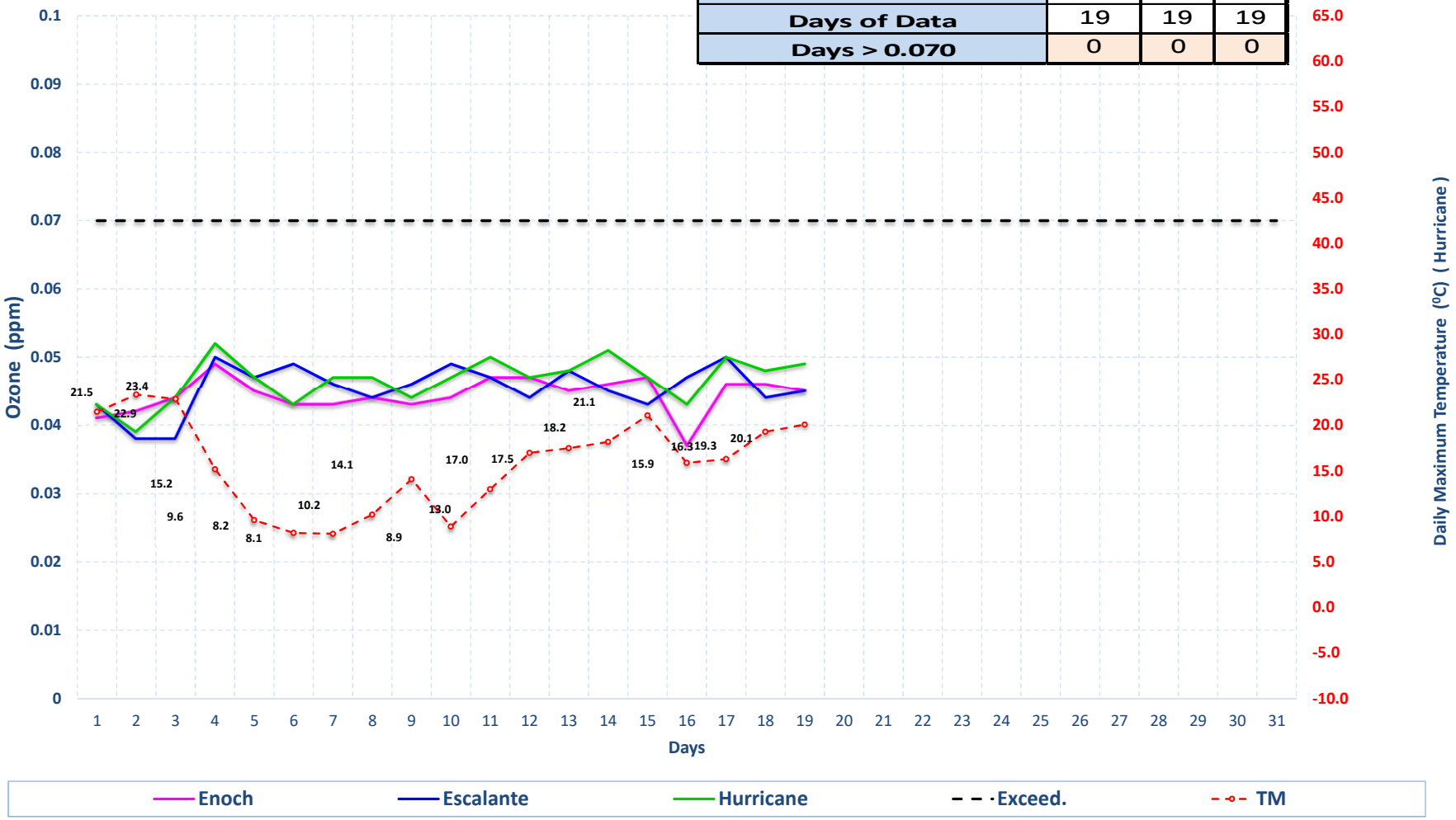
Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2022

	LN	SF
Arith Mean	.042	.043
8 -hr. Ozone 4th Max	.045	.045
Days of Data	19	19
Days > 0.070	0	0



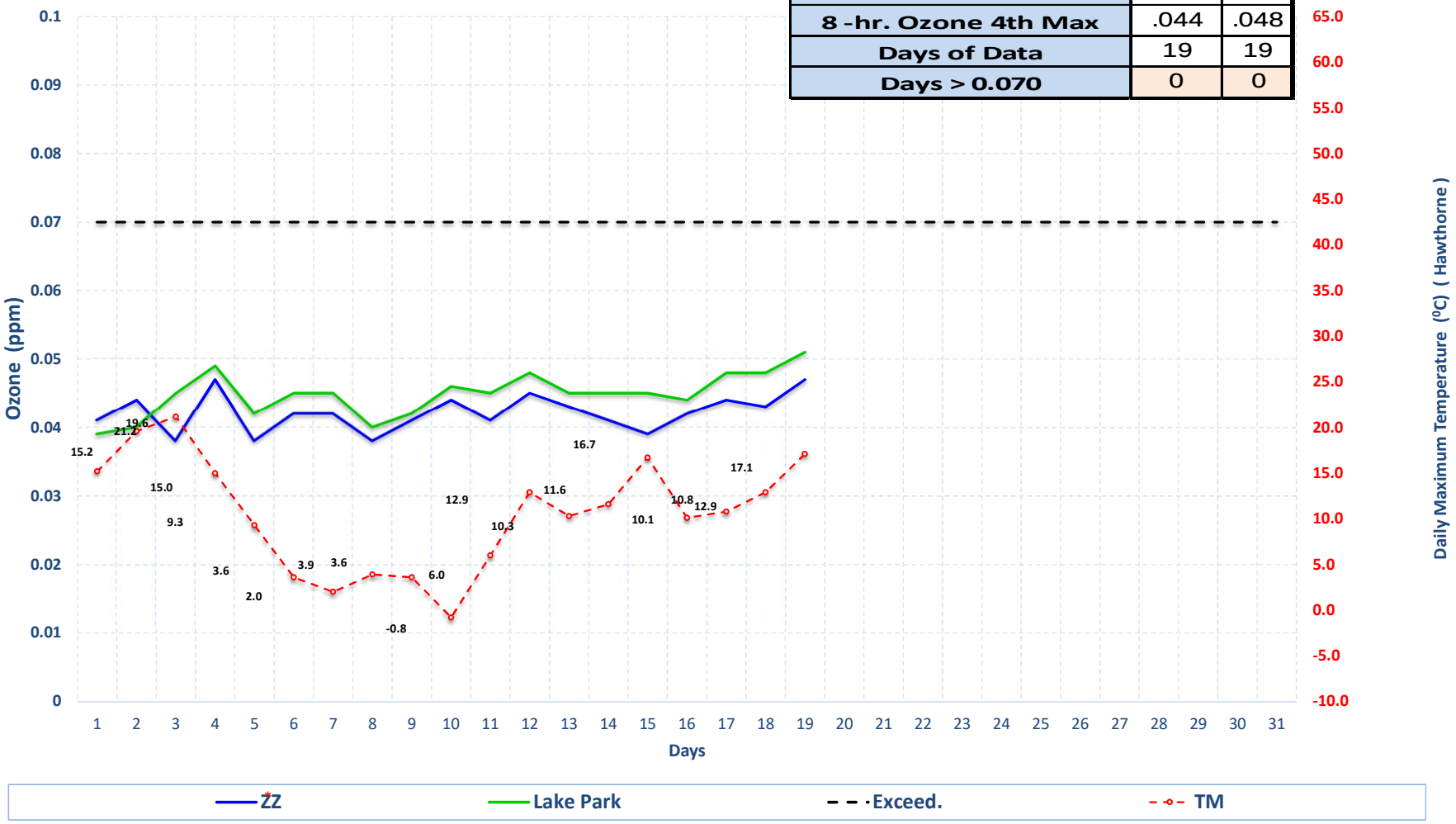
Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2022

	EN	ES	HC
Arith Mean	.044	.045	.047
8 -hr. Ozone 4th Max	.047	.049	.050
Days of Data	19	19	19
Days > 0.070	0	0	0



Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2022
Stations monitoring the Inland Port development

	ZZ	LP
Arith Mean	.042	.045
8 -hr. Ozone 4th Max	.044	.048
Days of Data	19	19
Days > 0.070	0	0



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