



State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

Air Quality Board

Kim Frost, *Chair*
Michelle Bujdoso, *Vice-Chair*
Tim Davis
Seth Lyman
Colton Norman
Sonja Norton
Lorin Palmer
John Rasband
Dave Spence
Bryce C. Bird,
Executive Secretary

DAQ-009-26a

UTAH AIR QUALITY BOARD MEETING FINAL AGENDA

Wednesday, April 1, 2026 - 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 1-475-299-8810 using access code: 449-801-632#, or via the Internet at meeting link:

meet.google.com/dpm-oqgm-nzk

- I. Call-to-Order and Roll Call.
- II. Dates of the Next Air Quality Board Meetings: May 6, 2026 and June 3, 2026
- III. Approval of the Minutes for the February 4, 2026, Board Meeting.
- IV. Propose for Public Comment: Amend Section R307-110-17, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits; Amend Utah State Implementation Plan, Section IX.H.12 and Section IX.H.13: Emission Limitations and Operating Practices. Presented by Ana Williams.
- V. Propose for Public Comment: Amend Section R307-110-11 to incorporate Utah State Implementation Plan Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide; Section IX.B.11, SO₂ Maintenance Provisions for Salt Lake County Nonattainment Area and Section IX.B.12, SO₂ Maintenance Provisions for Tooele County Nonattainment Area. Presented by Tasnuva Islam.
- VI. Propose for Public Comment: Amend Section R307-110-13 to incorporate Utah State Implementation Plan Section IX, Control Measures for Area and Point Sources, Part D, Ozone; Section IX.D.13.a, 2020 Uinta Basin Periodic Inventory Report and Section IX.D.13.b, 2023 Uinta Basin Periodic Inventory Report. Presented by Sheila Vance.

- VII. Informational Items.
 - A. Air Toxics. Presented by Leonard Wright.
 - B. Compliance. Presented by Harold Burge, Rik Ombach, and Chad Gilgen.
 - C. Monitoring. Presented by Thomas Greene.
 - 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 LeAnn Johnson, Office of Human Resources at (385) 226-4881, TDD (801) 536-4284 or by email at leannjohnson@utah.gov.

ITEM 3



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DAQ-006-26

UTAH AIR QUALITY BOARD MEETING February 4, 2026 – 1:30 p.m. 195 North 1950 West, Room 1015 Salt Lake City, Utah 84116

DRAFT MINUTES

I. Call-to-Order and Roll Call

Michelle Bujdoso called the meeting to order at 1:30 p.m.

Board members present: Michelle Bujdoso, Dave Spence, Tim Davis, Colton Norman (attended electronically), John Rasband (attended electronically), Sonja Norton (attended electronically), Seth Lyman (attended electronically)

Excused: Kim Frost

Executive Secretary: Bryce Bird

II. Date of the Next Air Quality Board Meeting: April 1, 2026

Mr. Bird stated that there are no items to bring to the Board in March. A poll will be sent to Board members to see if there will be a quorum for an April 1, 2026, meeting. If no quorum can attend on April 1st, another option would be April 8, 2026.

III. Approval of the Minutes for December 3, 2025, Board Meeting.

- Sonja Norton motioned to approve the minutes from the December 3, 2025, meeting. Dave Spence seconded. The motion carries unanimously.

IV. Five-Year Review: R307-210. Standards of Performance for New Stationary Sources. Presented by Jazmine Lopez.

Jazmine Lopez, Rules Coordinator at DAQ, stated that Utah Code Title 63G-3-305 requires each agency to review and justify each of its rules within five years of a rule's original effective date or within five years of the filing of the last five-year review. This review process is not a time to revise or amend the rules, but only to verify that the rule is still necessary and allowed under state and

federal statute. As part of this process, we are required to identify any comments received during and since the last five-year review of each rule. This process is not the time to revisit those comments or to respond to them. There have not been any comments received on rule R307-210.

The division has completed the five-year review of rule R307-210, Standards of Performance for New Stationary Sources. The result of the five-year review is found in the attached Five-Year Notice of Review and Statement of Continuation form. Staff recommend that the Board continue rule R307-210, Standards of Performance for New Stationary Sources, by approving the attached Five-Year Notice of Review and Statement of Continuation form to be filed with the Office of Administrative Rules.

- Colton Norman motioned to approve continuation of rule R307-210. Sonja Norton seconded. The motion carries unanimously.

V. Propose for Final Adoption: Amend R307-101. General Requirements; including Section R307-101-3. Version of Code of Federal Regulations Incorporated by Reference. Presented by Jazmine Lopez.

Jazmine Lopez, Rules Coordinator at DAQ, stated Section R307-101-3, Version of Code of Federal Regulations Incorporated by Reference, must be updated periodically to reflect changes to the federal air quality regulations as published in Title 40 of the Code of Federal Regulations (40 CFR). All published changes to 40 CFR that are relevant to the Utah Air Quality Rules from July 2, 2024, to September 30, 2025, are listed in the attached table, which is included in the Board packet.

Section R307-101-3 has been amended to identify the most recent version of 40 CFR, September 30, 2025, as the version that is incorporated throughout the Utah Air Quality Rules.

The division is also including additional necessary amendments to rule R307-101 to bring the rule into compliance with Executive Order 2021-12 requiring all departments to update their respective rules to align with the state rule writing manual standards.

At the November 5, 2025, meeting, the Board proposed the amendments to rule R307-101 for a 30-day public comment period from December 1, 2025, to December 31, 2025. During this time, the division received one comment. The comment was regarding air quality standards in general and does not require a formal response. No public hearing was requested by the associated due date. Staff recommend that the Board approve the amendments to rule R307-101 for final adoption.

Ms. Lopez clarified that the summary of changes table is only intended for inclusion in the Board packet and is not submitted to the Office of Administrative Rules. The summary table can be found within the packet on the Board's webpage.

Commissioner Norton requests that in the future any changes be highlighted in color in addition to the underline and strike-through notations. This will make it easier to see changes. Staff agreed to implement this suggestion.

- Dave Spence motioned to approve amendments to rule R307-101 for final adoption. Sonja Norton seconded. The motion carries unanimously.

VI. Informational Items.**A. Air Toxics. Presented by Leonard Wright.****B. Compliance. Presented by Harold Burge, Rik Ombach, and Chad Gilgen.****C. Monitoring. Presented by Lucas Bohne.**

Lucas Bohne, Environmental Scientist at DAQ, updated the Board on monitoring information, noting that there was only exceedance during December and January of PM_{2.5} at the Copperview site on January 1, 2026.

Commissioner Norton asked where does the division state the cause of exceedances. Mr. Bohne then described the data certification process which takes a little over a year. During pending validation, when there are events that could be considered exceptional events those are flagged and looked at during the data certification process and when staff is reviewing the annual and three-year average values.

Mr. Bohne explained that monitoring site identifiers are abbreviations derived from the site names. For instance, the identifier "NR" is assigned to the "Near-Road" site.

D. Other Items to be Brought Before the Board.

The 2025 annual report, which offers an overview of Utah's air quality and details the division's organization, activities, and progress throughout the year, is now available. Mr. Bird confirmed that the report has been posted on the Air Quality website at airquality.utah.gov.

Following Mayor Silvestrini's departure, the Governor's Office completed the recruitment process to fill the resulting Board vacancy. Mr. Bird reported that Mayor Lorin Palmer of Herriman City was selected as the Governor's recommendation after a review of all applications. Mayor Palmer's appointment must now undergo the required 30-day period before the Senate can schedule a hearing or vote for approval.

E. Board Meeting Follow-up Items.

Meeting adjourned at 1:51 p.m.

ITEM 4



State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-010-26

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

THROUGH: Jazmine Lopez, Rules Coordinator

FROM: Ana Williams, Environmental Scientist

DATE: March 19, 2026

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend Section R307-110-17, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits; Amend Utah State Implementation Plan, Section IX.H.12 and Section IX.H.13: Emission Limitations and Operating Practices.

On December 19, 2025, the Environmental Protection Agency (EPA) approved the redesignation of the Salt Lake City, UT and Provo, UT nonattainment areas to attainment for the 2006 24-hour PM_{2.5} standard and approved multiple related state implementation plan (SIP) submissions. Now that the Salt Lake City, UT and Provo, UT areas have been redesignated to attainment for the PM_{2.5} standard, the division has received several requests to update conditions contained in the PM_{2.5} SIP Sections IX.H.12 and IX.H.13, affecting seven total sources. Although the areas are technically in attainment, they must show continued maintenance of the standard for the next 20 years.

Clean Air Act Section 110(l) requires a non-interference or anti-backsliding demonstration if any SIP-approved rules are relaxed. EPA must incorporate this demonstration during their rulemaking process. The 110(l) demonstration must show that the relaxation will not interfere with continued attainment or maintenance of National Ambient Air Quality Standards, and quantitatively or qualitatively show that it has a negligible air quality impact. The 110(l) demonstration for two Part H amendments that will result in a slight increase in emission limitations for two sources, HF Sinclair Woods Cross Refinery (HF Sinclair) and McWane Ductile, can be found in Appendix A of the Board packet.

One emission limitation in SIP Section IX.H.12(g)(i)(A) for HF Sinclair Woods Cross Refinery's Reformer Reheat Furnace 6H1 is being increased from 0.15 lb/MMBtu to 0.20 lb/MMBtu. During the original drafting period of this emission limit, HF Sinclair proposed the existing limit based on best engineering judgement. This emission unit was constructed in 1957, and due to its age, HF Sinclair did not have existing vendor emission performance guarantees nor testing data. Since the final adoption of this emission limit, HF Sinclair has conducted engineering nitrogen oxide emissions testing and determined that the original limit of 0.15 lb/MMBtu is not achievable. After reviewing the submitted information, the division agrees with HF Sinclair's assessment and proposes that the limit on the Reformer Reheat Furnace 6H1 should be increased to 0.20 lb/MMBtu.

One emission limitation in SIP Section IX.H.13(c)(ii) for McWane Ductile's annealing oven is being increased from 63.29 MMBtu/hr to 76.5 MMBtu/hr. McWane Ductile has requested to reconstruct their existing annealing oven, which will result in an increase in the annealing oven's size and burner capacity. The new oven is needed to improve balanced heating of the products, add the ability to control the target temperature of the oven, and improve the thermal penetration in the oven. After reviewing the submitted application, the division is proposing that the limit on the annealing oven should be increased to 76.5 MMBtu/hr.

In addition to these two emission limitation amendments, the division is proposing to remove conditions from Section IX.H.13 for the following five sources: (1) Brigham Young University – Main Campus; (2) Geneva Nitrogen Inc. – Geneva Nitrogen Plant; (3) Payson City Corporation – Payson City Power; (4) Provo City Power – Power Plant; and (5) Springville City Corporation – Whitehead Power Plant. These five sources fall below the 70 ton per year threshold for Serious 2006 24-hour PM_{2.5} major stationary sources and are therefore considered minor sources and were not included in EPA's final redesignation action. The removal of these five sources will not impact existing permit conditions and requirements for the sources, and these sources will continue to be regulated through the division's Minor Source Permitting Section.

Recommendation: Staff recommend the Board approve the amendment to Section R307-110-17, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits; Amend Utah State Implementation Plan, Section IX.H.12 and Section IX.H.13: Emission Limitations and Operating Practices, for a 30-day public comment period.

State of Utah
Administrative Rule Analysis
Revised May 2025

NOTICE OF SUBSTANTIVE CHANGE

TYPE OF FILING: Amendment

Rule or section number:

R307-110-17

Filing ID: OFFICE USE ONLY

Date of previous publication (only for CPRs):

Agency Information

1. Title catchline:	Environmental Quality, Air Quality	
Building:	Multi-Agency State Office Building	
Street address:	195 N 1950 W	
City, state:	Salt Lake City, UT	
Mailing address:	PO Box 144820	
City, state and zip:	Salt Lake City, UT 84114-4820	
Contact persons:		
Name:	Phone:	Email:
Jazmine Lopez	801-536-4050	jazminelopez@utah.gov
Ana Williams	385-306-6505	anawilliams@utah.gov

Please address questions regarding information on this notice to the persons listed above.

General Information

2. Rule or section catchline:	
R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.	
3. Are any changes in this filing because of state legislative action?	Changes are not because of legislative action.
If yes, any bill number and session:	
4. Purpose of the new rule or reason for the change:	
The Utah Air Quality Board has proposed for public comment amendments to the Utah State Implementation Plan (SIP), amending Subsections IX.H.12 and IX.H.13 Source-Specific Emission Limitations to comply with source requests for emission limitation changes. Section R307-110-17 incorporates SIP Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits into the rule, and shall be amended to change the Board adoption date to the anticipated adoption date of the amended plan.	
5. Summary of the new rule or change:	
This rule amendment is in response to source requests to change emission limitations after US EPA approval of the Utah PM2.5 nonattainment redesignation. The following plan amendments are being proposed: (1) Increase the emission limitation for one source under Subsection IX.H.12 Source-Specific Emission Limitations. (2) Increase the emission limitation for one source under Subsection IX.H.13 Source-Specific Emission Limitations. (3) Remove requirements for five minor sources under Subsection IX.H.13 Source-Specific Emission Limitations that do not need to be included in the state requirements due to minor source status. The plan also includes a 110(l), or anti-backsliding, demonstration to show that the relaxation of requirements will not interfere with continued attainment or maintenance of National Ambient Air Quality Standards, and quantitatively or qualitatively show that it has a negligible air quality impact.	

Fiscal Information

6. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:	
A. State budget:	
This rule amendment is not expected to create additional costs or savings for the state government. These facilities are already permitted and inspected under existing rules and have existing compliance requirements in place.	
B. Local governments:	
This rule amendment is not expected to impact local governments; therefore, no costs or savings are anticipated.	

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

This rule amendment is not expected to impact small businesses; therefore, no costs or savings are anticipated.

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

This rule amendment is not expected to create additional costs or savings for seven non-small businesses. The increased emission limitations for two non-small businesses will not fundamentally change how those businesses operate or are inspected because all existing requirements will stay the same for these two sources. The removal of the five non-small businesses from Subsection IX.H.13 will not change existing minor source permitting requirements or compliance requirements, and therefore all existing requirements will stay the same for these five sources.

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 amendment does not apply to persons other than small business, non-small businesses, state, or local government entities; therefore, no additional costs are expected as a result of these changes.

F. Compliance costs for affected persons:

There are no additional compliance costs expected for the seven non-small businesses because all existing compliance requirements will stay the same for these sources.

G. Regulatory Impact Summary Table (This table includes only fiscal impacts the agency was able to measure. If the agency could not estimate an impact, it is excluded from this table but described in boxes A through F.)**Regulatory Impact Summary Table**

Fiscal Cost	FY2026	FY2027	FY2028	FY2029	FY2030
State Budget	\$0	\$0	\$0	\$0	\$0
Local Governments	\$0	\$0	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0	\$0	\$0
Other Persons	\$0	\$0	\$0	\$0	\$0
Total Fiscal Cost	\$0	\$0	\$0	\$0	\$0
Fiscal Benefits	FY2026	FY2027	FY2028	FY2029	FY2030
State Budget	\$0	\$0	\$0	\$0	\$0
Local Governments	\$0	\$0	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0	\$0	\$0
Other Persons	\$0	\$0	\$0	\$0	\$0
Total Fiscal Benefits	\$0	\$0	\$0	\$0	\$0
Net Fiscal Benefits	\$0	\$0	\$0	\$0	\$0

H. Department head comments on fiscal impact and approval of regulatory impact analysis:

The Executive Director of the Department of Environmental Quality, Tim Davis, has reviewed and approved this regulatory impact 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:**

Section 19-2-104	40 CFR 51 Subpart Z	

Incorporation by Reference Information**8. Incorporation by Reference** (if this rule incorporates more than two items by reference, please include additional tables):

A. This rule adds or updates the following title of material incorporated by reference (a copy of the material incorporated by reference must be submitted to the Office of Administrative Rules. *If none, leave blank*):

Official Title of Materials Incorporated	Utah State Implementation Plan, Section IX, Control Measures for Area and Point
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(from title page)	Sources, Part H, Emission Limits and Operating Practices.
Publisher	Division of Air Quality, Utah Department of Environmental Quality
Issue Date	July 1, 2026
Issue or Version	

B. This rule adds or updates the following title of material incorporated by reference (a copy of the material incorporated by reference must be submitted to the Office of Administrative Rules. *If none, leave blank*):

Official Title of Materials Incorporated (from title page)	
Publisher	
Issue Date	
Issue or Version	

Public Notice Information

9. The public may submit written or oral comments to the agency identified in box 1.

A. Comments will be accepted until: 05/15/2026

B. A public hearing (optional) will be held (The public may request a hearing by submitting a written request to the agency, as outlined in Section 63G-3-302 and Rule R15-1.):

Date:	Time (hh:mm AM/PM):	Place (physical address or URL):
05/12/2026	03:00PM - 04:00PM	A public hearing is set for May 12, 2026. Further details may be found below. The hearing will be cancelled should no request for one be made by May 11, 2026, at 10 AM MT. The final status of the public hearing will be posted on May 11, 2026, after 10 AM MT. The status of the public hearing may be checked at the following website location under the corresponding rule. https://deq.utah.gov/public-notices-archive/air-quality-rule-plan-changes-open-public-comment Interested Persons can participate in person or electronically, via the internet. In Person: MASOB 195 N. 1950 W. Salt Lake City, UT, 84116, First Floor, Air Quality Board Room Virtual Attendance: Time zone: America/Denver Google Meet joining info: Video call link: https://meet.google.com/tvd-adeq-xry Or dial: (US) +1 402-307-1278 PIN: 367 842 220#

To the agency: If more than one hearing is planned to take place, continue to add rows.

10. This rule change MAY become effective on: 07/01/2026

NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date.

Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 63G-3-302, 63G-3-303, and 63G-3-402. The office may return incomplete forms to the agency, 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, Division of Air Quality	Date:	03/13/2026
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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 ~~May 7, 2025~~ July 1, 2026, pursuant to Section 19-2-104, is incorporated by reference and made a part of Rule R307-110.

KEY: air pollution, PM10, PM2.5, ozone

Date of Last Change: ~~July 2, 2025~~ 2026

Notice of Continuation: December 1, 2021

Authorizing, and Implemented or Interpreted Law: 19-2-104

H.12. Source-Specific Emission Limitations in Salt Lake City – UT PM2.5 Nonattainment Area

- a. ATK Launch Systems Inc. Promontory
 - i. During the period November 1 to February 28/29 on days when the 24-hour average PM2.5 levels exceed 35 µg/m³ at the nearest real-time monitoring station, the open burning of reactive wastes with properties identified in 40 CFR 261.23 (a) (6) (7) (8) may be conducted when the 24-hour average PM2.5 levels exceed 35 µg/m³ at the nearest real time monitoring station in limited quantities. Limited quantities, as authorized in the facility's RCRA Subpart X permit, of time sensitive reactive wastes may be open burned when the 24-hour average PM2.5 levels exceed 35 µg/m³ at the nearest real-time monitoring station.
 - ii. During the period November 1 to February 28/29, on days when the 24-hour average PM2.5 levels exceed 35 µg/m³ at the nearest real-time monitoring station, the following shall not be tested:
 - A. Propellant, energetics, pyrotechnics, flares and other reactive compounds greater than 2,400 lbs. per day; or
 - B. Rocket motors less than 1,000,000 lbs. of propellant per motor subject to the following exception:
 - I. A single test of rocket motors less than 1,000,000 lbs. of propellant per motor is allowed on a day when the 24-hour average PM2.5 level exceeds 35 µg/m³ at the nearest real-time monitoring station provided notice is given to the Director of the Utah Air Quality Division. No additional tests of rocket motors less than 1,000,000 lbs. of propellant may be conducted during the inversion period until the 24-hour average PM2.5 level has returned to a concentration below 35 µg/m³ at the nearest real-time monitoring station.
 - C. During this period, records will be maintained identifying the size of the rocket motors tested and the 24-hour average PM2.5 level at the nearest real-time monitoring station on days when motor testing occurs.
 - iii. Natural Gas-Fired Boilers
 - A. Building M-576
 - I. One 71 MMBTU/hr boiler shall be upgraded with low NO_x burners and flue gas recirculation by January 2016. The boiler shall be rated at a maximum of 9 ppm. The remaining boiler shall not consume more than 100,000 MCF of natural gas per rolling 12-month period unless upgraded so the NO_x emission rate is no greater than 30 ppm.

II. Emissions to the atmosphere from the Cleaver Brooks 71 MMBTU/hr boiler in building M-576 shall not exceed the following concentration:

1. Pollutant ppm_{dv} (3% O₂ dry)
NOX 9
2. Compliance with the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP.
3. Subsequent to initial compliance testing, stack testing is required every three years.

B. Building M-14

I. The two 25 MMBTU/hr boilers shall be upgraded with low NO_x burners and flue gas recirculation by December 31, 2024. The boiler shall be rated at a maximum of 9 ppm.

II. Emissions to the atmosphere from the two (2) Cleaver Brooks 25 MMBTU/hr boilers in building M-14 shall not exceed the following concentrations:

1. Pollutant ppm_{dv} (3% O₂ dry)
NOX 9
2. Compliance with the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP.
3. Subsequent to initial compliance testing, stack testing is required every three years.

b. Big West Oil, LLC Refinery

- i. NO_x emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations.

Emission Points	Emission Rate (lb/MMBtu)
A. FCC Heater H-101	0.16 lb/MMBtu
B. Reformer Heaters H-621, 622, 624	0.08 lb/MMBtu
C. #1 Boiler	0.035 lb/MMBtu
D. #6 Boiler	0.035 lb/MMBtu

- ii. Initial NO_x stack testing has been performed for the #1 Boiler and #6 Boiler. For these units, stack testing shall be performed no later than December 31st, 2025. Subsequent stack testing shall be conducted at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as

outlined in IX.H.11.e.

iii. Initial compliance testing for FCC Heater H-101, Reformer Heater H-621, Reformer Heater H-622, and Reformer Heater H-624 is required. The initial test shall be performed no later than December 31st, 2025. After the initial compliance test, stack testing shall be performed at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.

iv. In lieu of the stack testing requirements listed above, any units equipped with a CEMs shall determine compliance with the emission limits by the CEMs. For units equipped with CEMs, compliance shall be determined on a 30-day rolling average. The CEMs shall operate as outlined in IX.H.11.f.

v. Alternate Startup and Shutdown Requirements

A. During any day which includes startup or shutdown of the FCCU, combined emissions of SO₂ shall not exceed 1.2 tons per day (tpd). For purposes of this subsection, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

B. The total number of days which include startup or shutdown of the FCCU shall not exceed ten (10) per 12-month rolling period.

vi. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	Control Equipment
FCCU Regenerator	Flue gas blowback "Pall Filter," quaternary cyclones with fabric filter
H-404 #1 Crude Heater	Ultra-low NO _x burners
Refinery Flares	Subpart Ja, and MACT CC flaring standards
SRU	Tail gas incinerator and redundant caustic scrubber
Product Loading Racks	Vapor recovery and vapor combustors
Wastewater Treatment System	API separator fixed cover, carbon adsorber canisters to be installed 2019

c. Chemical Lime Company (LHoist North America) Lime Production Kiln

i. No later than January 1, 2019, or upon source start-up, whichever comes later, SNCR technology shall be installed on the Lime Production Kiln.

A. Effective January 1, 2019, or upon source start-up, whichever comes later, NO_x emissions shall not exceed 56 lb/hr. (3-hr rolling average)

- 1 B. Compliance with the above emissions limit shall be determined by stack
2 testing as outlined in Section IX Part H.11.e of this SIP.
3
- 4 ii. No later than January 1, 2019, or upon source start-up, whichever comes later, a
5 baghouse control technology shall be installed and operating on the Lime
6 Production Kiln.
7
- 8 A. Effective January 1, 2019, or upon source start-up, whichever comes later, PM
9 emissions shall not exceed 0.12 pounds per ton (lb/ton) of stone feed. (3-hr
10 rolling average)
11
- 12 B. Effective January 1, 2019, or upon source start-up, whichever comes later,
13 PM2.5 (filterable + condensable) emissions shall not exceed 1.5 lbs/ton of
14 stone feed. (3-hr rolling average)
15
- 16 C. Compliance with the above emission limits shall be determined by stack
17 testing as outlined in Section IX Part H.11.e of this SIP and in accordance
18 with 40 CFR 63 Subpart AAAAA.
19
- 20 iii. An initial compliance test is required no later than January 1, 2019 (if start-up
21 occurs on or before January 1, 2019) or within 180 days of source start-up (if
22 start-up occurs after January 1, 2019) All subsequent compliance testing shall be
23 performed at least once annually based upon the date of the last compliance test.
24
- 25 iv. Upon plant start-up kiln emissions shall be exhausted through the baghouse during
26 all startup, shutdown, and operations of the kiln.
27
- 28 v. Start-up/shut-down provisions for SNCR technology are as follows:
29
- 30 A. No ammonia or urea injection during startup until the combustion gases
31 exiting the kiln reach the temperature when NOx reduction is effective, and
32
- 33 B. No ammonia or urea injection during shutdown.
34
- 35 C. Records of ammonia or urea injection shall be documented in an operations
36 log. The operations log shall include all periods of start-up/shut-down and
37 subsequent beginning and ending times of ammonia or urea injection which
38 documents v.a and v.b above.
39
- 40 d. Chevron Products Company – Salt Lake Refinery
41
- 42 i. NOx Emissions to the atmosphere from the indicated emission points shall not
43 exceed the following rates and concentrations.
44
- | | |
|-------------------------|--------------------------|
| 45 Emission Points | Emission Rate (lb/MMBtu) |
| 46 A. F-11005 Boiler #5 | 0.20 lb/MMBtu |

B. F-11006 Boiler #6	0.20 lb/MMBtu
C. F-11007 Boiler #7	0.20 lb/MMBtu
D. F-21001 Crude Furnace #1	0.09 lb/MMBtu
E. F-21002 Crude Furnace #2	0.09 lb/MMBtu
F. F-32021 FCC Furnace #1	0.17 lb/MMBtu
G. F-32023 FCC Furnace #2	0.17 lb/MMBtu
H. F-35001 Reformer Furnace F-1	0.17 lb/MMBtu
I. F-35002 Reformer Furnace F-2	0.17 lb/MMBtu
J. F-36017 Alkylation Furnace	0.12 lb/MMBtu
K. F-70001 Coker Furnace	0.16 lb/MMBtu
L. F-66100 VGO Furnace #1	0.05 lb/MMBtu
M. F-66200 VGO Furnace #2	0.05 lb/MMBtu

- ii. Initial NO_x stack testing has been performed for the following units: F-11005 Boiler #5, F-11006 Boiler #6, F-21001 Crude Furnace #1, F-21002 Crude Furnace #2, F-36017 Alkylation Furnace, and F-70001 Coker Furnace. For these units, stack testing shall be conducted at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.
- iii. For F-11007 Boiler #7, NO_x emissions shall be monitored by CEMs to determine compliance. The CEM shall operate as outlined in IX.H.11.f.
- iv. Initial compliance testing for F-66100 VGO Furnace #1 and F-66200 VGO Furnace #2 is required. The initial test shall be performed no later than December 31st, 2025. After the initial compliance test, stack testing shall be performed at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.
- v. A stack testing port shall be installed for F-32021 FCC Furnace #1, F-32023 FCC Furnace #2, F-35001 Reformer Furnace F-1, and F-35002 Reformer Furnace F-2 and initial compliance testing shall be performed no later than December 31st, 2027. After the initial compliance test, stack testing shall be performed at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.
- vi. In lieu of the stack testing requirements listed above, any units equipped with a CEMs shall determine compliance with the emission limits by the CEMs. For units equipped with CEMs, compliance shall be determined on a 30-day rolling average. The CEMs shall operate as outlined in IX.H.11.f.
- vii. Emergency and Standby Equipment and Alternative Fuels
 - A. Plant coke may be burned in the FCC Catalyst Regenerator.

viii. Compressor Engine Requirements

- A. Emissions of NOx from each rich-burn compressor engine shall not exceed the following:

Engine Number	NOx in ppmvd @ 0% O2
K35001	236
K35002	208
K35003	230

- B. Initial stack testing to demonstrate compliance with the above emission limitations shall be performed no later than January 1, 2019, and at least once every three years thereafter. Stack testing shall be performed as outlined in IX.H.11.e.

- ix. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	Control Equipment
Boilers: 5, 6, 7	Low NOx burners and flue gas recirculation (FGR)
Cooling Water Towers	High efficiency drift eliminators
Crude Furnaces F21001, F21002	Low NOx burners
Crude Oil Loading	Vapor Combustion Unit (VCU)
FCC Regenerator Stack	Vacuum gas oil hydrotreater, Electrostatic precipitator (ESP) and cyclones
Flares: Flare 1, 2	Flare gas recovery system
HDS Furnaces F64010, F64011	Low NOx burners
Reformer Compressor Drivers K35001, K35002, K35003	Selective Catalytic Reduction (SCR)
Sulfur Recovery Unit 1	Tail gas treatment unit and tail gas incineration
Sulfur Recovery Unit 2	Tail gas treatment unit and tail gas incineration
Wastewater Treatment Plant	Existing wastewater controls system of induced air flotation (IAF) and regenerative thermal oxidation (RTO). Upon completion of startup and initial commissioning, the Dissolved Nitrogen Flootation (DNF) process is allowed instead of the IAF system

e. Compass Minerals Ogden Inc.

- i. NO_x emissions to the atmosphere from the indicated emission point shall not exceed the following concentrations:

Emission Points	Concentration (ppm)	lb/hr
Boiler #1	9.0	1.3
Boiler #2	9.0	1.3

Compliance with the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP. A compliance test shall be performed at least annually subsequent to the initial compliance test.

- ii. PM_{2.5} emissions (filterable+condensable) to the atmosphere from each of the following emission points shall not exceed the listed concentration and lb/hr emission rates:

Emission Unit	PM _{2.5} Emission Rate (lb/hr)	Concentration Emission Rate (grains/dscf)
AH-500	1.61	0.01
AH-502	0.74	0.04
AH-513	1.49	0.0114
BH-001	0.37	0.01
BH-002	0.47	0.01
BH-008	4.25	0.01
BH-501	1.15	0.01
BH-502	0.06	0.0053
BH-503	0.23	0.01
BH-505	0.12	0.01
AH-1555	0.39	0.01
BH-1400	2.78	0.02
AH-692	0.12	0.01
BH-1516	0.22	0.01

A. Compliance with the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP. Compliance testing shall be performed annually.

B. Process emissions shall be routed through operating controls prior to being emitted to the atmosphere.

- iii. Emissions of VOC from all Magnesium Chloride Evaporators (four stacks total) shall not exceed 6.18 lb/hr.

A. Compliance shall be determined by stack test as outlined in Section IX Part

H.11.e of this SIP. Compliance testing shall be performed at least once every three years.

- B. Process emissions shall be routed through operating controls prior to being emitted to the atmosphere.

f. Hexcel Corporation: Salt Lake Operations

- i. The following limits shall not be exceeded for fiber line operations:
 - A. 5.50 MMscf of natural gas consumed per day.
 - B. 0.061 MM pounds of carbon fiber produced per day.
 - C. Compliance with each limit shall be determined by the following methods:
 - I. Natural gas consumption shall be determined by examination of natural gas billing records for the plant and onsite pipe-line metering.
 - II. Fiber production shall be determined by examination of plant production records.
 - III. Records of consumption and production shall be kept on a daily basis for all periods when the plant is in operation.
- ii. After a shutdown and prior to startup of fiber lines 13 to 16, the line's baghouse(s) and natural gas injection dual chambered regenerative thermal oxidizer shall be started and remain in operation during production.
 - A. During fiber line production, the static pressure differential across the filter media shall be within the manufacturer's recommended range and shall be recorded daily.
 - B. The manometer or the differential pressure gauge shall be calibrated according to the manufacturer's instructions at least once every 12 months.
- iii. Filter boxes will be installed on Fiber lines 13 and 14 to control PM_{2.5} emissions no later than December 31, 2019.
- iv. After a shutdown and prior to startup of the fiber lines, the residence time and temperature associated with the regenerative thermal-oxidation fume incinerators and solvent-coating fume incinerators shall be started and remain in operation during production.
 - A. Unless otherwise indicated, the carbon fiber production thermal-oxidation fume incinerators the minimum temperature shall be 1,400 deg F and the

residence time shall be greater than or equal to 0.5 seconds
 Solvent-coating fume incinerators the minimum temperature shall be 1,450 deg F and the residence time shall be greater than or equal to 0.5 seconds

For fiber lines 6, 7, 8, 10, 11, 12, and the line associated with the Research and Development Facility, the solvent coating fume incinerators temperature shall range from 1,400 to 1,700 deg F and the residence time shall be greater than or equal to 1.0 second

Residence times shall be determined by:

$$R = V /$$

Q_{max}

Where

R = residence time

V = interior volume of the incinerator – ft³

Q_{max} = maximum exhaust gas flow rate – ft³/second

- B. Incinerator temperatures shall be monitored with temperature sensing equipment that is capable of continuous measurement and readout of the combustion temperature. The readout shall be located such that an inspector/operator can at any time safely read the output. The measurement shall be accurate within $\pm 25^{\circ}\text{F}$ at operating temperature. The measurement need not be continuously recorded. All instruments shall be calibrated against a primary standard at least once every 180 days. The calibration procedure shall be in accordance with 40 CFR 60, Appendix A, Method 2, paragraph 6.3, and 10.31, or use a type "K" thermocouple.

g. HF Sinclair Woods Cross Refinery

- i. NO_x Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations.

Emission Points	Emission Rate (lb/MMBtu)
A. Reformer Reheat Furnace 6H1	~~0.15~~ 0.20 lb/MMBtu
B. Crude Furnace #1 8H2	0.04 lb/MMBtu
C. NHDS Reactor Charge Furnace 12H1	0.10 lb/MMBtu
D. Fractionator Charge Heater 20H2	0.04 lb/MMBtu
E. Boiler #5	0.02 lb/MMBtu
F. Boiler #8	0.02 lb/MMBtu
G. Boiler #9	0.02 lb/MMBtu
H. Boiler #10	0.02 lb/MMBtu
I. Boiler #11	0.02 lb/MMBtu

- ii. A stack testing port shall be installed for Reformer Reheat Furnace 6H1 and initial compliance testing shall be performed no later than December 31st, 2028. After

the initial compliance test, stack testing shall be performed at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.

- iii. Initial NO_x stack testing has been performed for the following units: Crude Furnace #1 8H2, NHDS Reactor Charge Furnace 12H1, Boiler #5, Boiler #8, Boiler #9, Boiler #10, and Boiler #11. For these units, stack testing shall be conducted at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.
- iv. Initial compliance testing for the Fractionator Charge Heater 20H2 is required. The initial test shall be performed no later than December 31st, 2025. After the initial compliance test, stack testing shall be performed at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.
- v. In lieu of the stack testing requirements listed above, any units equipped with a CEMs shall determine compliance with the emission limits by the CEMs. For units equipped with CEMs, compliance shall be determined on a 30-day rolling average. The CEMs shall operate as outlined in IX.H.11.f.
- vi. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	Control Equipment
Process heaters and boilers	Boilers 8&11: LNB+SCR Boilers 5, 9 & 10: SCR Process heaters 20H2, 20H3, 24H1, 25H1: ULNB
Cooling water towers 10, 11	High efficiency drift eliminators
FCCU regenerator stacks	WGS with Lo-TOx
Flares	Flare gas recovery system
Sulfur recovery unit	Tail gas incineration and WGS with Lo-TOx
Wastewater treatment plant	API separators, dissolved gas floatation (DGF), moving bed bio-film reactors (MBBR)

h. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

- A. Maximum total mileage per calendar day for diesel-powered ore and waste haul trucks shall not exceed 30,000 miles.

KUC shall keep records of daily total mileage for all periods when the mine is in operation. KUC shall track haul truck miles with a Global

Positioning System or equivalent. The system shall use real time tracking to determine daily mileage.

- B. To minimize fugitive dust on roads at the mine, the owner/operator shall perform the following measures:
 - I. Apply water to all active haul roads as weather and operational conditions warrant except during precipitation or freezing weather conditions, and shall apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.
 - II. Chemical dust suppressant shall be applied as weather and operational conditions warrant except during precipitation or freezing weather conditions on unpaved access roads that receive haul truck traffic and light vehicle traffic.
 - III. Records of water and/or chemical dust control treatment shall be kept for all periods when the BCM is in operation.
 - IV. KUC is subject to the requirements in the most recent federally approved Fugitive Emissions and Fugitive Dust rules.
- C. The In-pit crusher baghouse shall not exceed a PM_{2.5} emission limit of 0.78 lbs/hr (0.007 gr/dscf) PM_{2.5} monitoring shall be performed by stack testing every three years.

ii. Copperton Concentrator (CC)

- A. Control emissions from the Product Molybdenite Dryers with a scrubber during operation of the dryers.

During operation of the dryers, the static pressure differential between the inlet and outlet of the scrubber shall be within the manufacturer's recommended range and shall be recorded weekly.

The manometer or the differential pressure gauge shall be calibrated according to the manufacturer's instructions at least once per year.

The remaining heaters shall not operate more than 300 hours per rolling 12- month period unless upgraded so the NO_x emission rate is no greater than 30 ppm.

i. Kennecott Utah Copper (KUC): Power Plant

i. Utah Power Plant

A. The following requirements are applicable to Unit #4:

- I. Only natural gas shall only be used as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. Unit #4 may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment. The Director shall be notified of the curtailment within 48 hours of when it begins and within 48 hours of when it ends.
- II. Emissions to the atmosphere when burning natural gas shall not exceed the following rates and concentrations:

Pollutant	grains/dscf	ppmdv	lbs/hr	lbs/MMBtu
68oF. 29.92 in Hg		3% O2		

1. PM2.5:
Filterable 0.004
Filterable +
condensabe 0.03

2. NOx: 30 32 0.04

B. Upon commencement of operation of Unit #4, stack testing to demonstrate compliance with each emission limitation in IX.H.12.j.i.A and IX.H.12.j.i.B shall be performed as follows:

* Initial compliance testing for the Unit 4 boiler is required. Initial testing shall be performed when burning natural gas. The initial test shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

The limited use of natural gas during maintenance firings and break-in firings does not constitute operation and does not require stack testing.

Pollutant	Test Frequency
I. PM2.5	every year

II. NOx	every year
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C. Unit #5 (combined cycle, natural gas-fired combustion turbine) shall not exceed the following emission rates to the atmosphere:

Pollutant	lbs/hr	ppmdv (15% O2 dry)
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- I. PM2.5 with duct firing:
Filterable + condensable 18.8
- II. VOC: 2.0
- III. NOx: 2.0

D. Upon commencement of operation of Unit #5*, stack testing to demonstrate compliance with the emission limitations in IX.H.12.m.i.B shall be performed as follows for the following air contaminants

* Initial compliance testing for the natural gas turbine and duct burner is required. The initial test shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

The limited use of natural gas during maintenance firings and break-in firings does not constitute operation and does not require stack testing.

Pollutant	Test Frequency
I. PM2.5	every year
II. NOx	every year
III. VOC	every year

j. Kennecott Utah Copper: Smelter and Refinery

i. Smelter:

A. Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

- I. Main Stack (Stack No. 11)
 - 1. PM2.5
 - a. 85 lbs/hr (filterable)
 - b. 434 lbs/hr (filterable + condensable)
 - 2. SO2
 - a. 552 lbs/hr (3 hr. rolling average)
 - b. 422 lbs/hr (daily average)
 - 3. NOx 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_x

a. 14 lbs/hr, (calendar-day average)

- B. Stack testing to show compliance with the emissions limitations of Condition (A) above shall be performed as specified below:

EMISSION POINT	POLLUTANT	TEST FREQUENCY
I. Main Stack (Stack No. 11)	PM _{2.5}	Every Year
	SO ₂	CEM
	NO _x	CEM
II. Holman Boiler	NO _x	Every three years and CEMS or alternate method according to applicable NSPS Standards

The Holman boiler shall use an EPA approved test method every three years and in between years use or an approved CEMS or alternate method according to applicable NSPS standards.

- C. During startup/shutdown operations, NO_x and SO₂ emissions are monitored by CEMS or alternate methods in accordance with applicable NSPS standards.
- D. KUC must operate and maintain the air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

ii. Refinery:

- A. Emissions to the atmosphere from the indicated emission point shall not exceed the following rate:

EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
I. The sum of two (Tankhouse) Boilers	NO _x	9.5 lbs/hr (before December 2020)
II. (Upgraded Tankhouse Boiler)	NO _x	1.5 lbs/hr (After December 2020)
III. Combined Heat Plant	NO _x	5.96 lbs/hr

- B. Stack testing to show compliance with the above emission limitations shall be performed as follows:

EMISSION POINT	POLLUTANT	TESTING FREQUENCY
I. Upgraded Tankhouse Boilers	NOx	every three years*
II. Combined Heat Plant	NOx	every year

*Stack testing shall be performed on boilers that have operated more than 300 hours during a three-year period.

- C. One 82 MMBTU/hr Tankhouse boiler shall be upgraded to meet a NOx rating of 9 ppm no later than December 31, 2020. The remaining Tankhouse boiler shall not consume more than 100,000 MCF of natural gas per rolling 12-month period unless upgraded so the NOx emission rate is no greater than 30 ppm.
- D. KUC must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. Records shall be kept on site which indicate the date and time of startups and shutdowns.

k. Nucor Steel Mills

- i. Emissions to the atmosphere from the indicated emission points shall not exceed the following rates:

A. Electric Arc Furnace Baghouse

I. PM2.5

1. 17.4 lbs/hr (24 hr. average filterable)
2. 29.53 lbs/hr (24 hr. average condensable)

II. SO2

1. 93.98 lbs/hr (3 hr. rolling average)
2. 89.0 lbs/hr (daily average)

III. NOx 59.5 lbs/hr (calendar-day average)

IV. VOC 22.20 lbs/hr

B. Reheat Furnace #1 NOx 15.0 lb/hr

C. Reheat Furnace #2 NOx 8.0 lb/hr

- ii. Stack testing to show compliance with the emissions limitations of Condition (i) above shall be performed as outlined in IX.H.11.e and as specified below:

EMISSION POINT	POLLUTANT	TEST FREQUENCY
A. Electric Arc Furnace		
Baghouse	PM2.5	every year
	SO2	CEM
	NOx	CEM
	VOC	every year
B. Reheat Furnace #1	NOx	every year
C. Reheat Furnace #2	NOx	every year

- iii. Testing Status (To be applied to (i) and (ii) above)

- A. To demonstrate compliance with the Electric Arc Furnace stack mass emissions limits for SO2 and NOx of Condition (i)(A) above, Nucor shall calibrate, maintain, and operate the measurement systems for continuously monitoring for SO2 and NOx concentrations and stack gas volumetric flow rates in the Electric

Arc Furnace stack. Such measurement systems shall meet the requirements of R307-170.

- B. For PM2.5 testing, 40 CFR 60, Appendix A, Method 5D, or another EPA approved method acceptable to the Director, shall be used to determine total TSP emissions. If TSP emissions are below the PM2.5 limit, that will constitute compliance with the PM2.5 limit. If TSP emissions are not below the PM2.5 limit, the owner/operator shall retest using EPA approved methods specified for PM2.5 testing, within 120 days.

- C. Startup/shutdown NOx and SO2 emissions are monitored by CEMS.

1. PacifiCorp Energy: Gadsby Power Plant

- i. Steam Generating Unit #1:

- A. Emissions of NOx shall be no greater than 179 lbs/hr on a three (3) hour block average basis.
- B. Emissions of NOx shall not exceed 336 ppmdv (@ 3% O2, dry)
- C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NOx and O2 monitors to determine compliance with the NOx limitation. The CEM shall operate as outlined in IX.H.11.f.

ii. Steam Generating Unit #2:

- A. Emissions of NO_x shall be no greater than 204 lbs/hr on a three (3) hour block average basis.
- B. Emissions of NO_x shall not exceed 336 ppmdv (@ 3% O₂, dry)
- C. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_x and O₂ monitors to determine compliance with the NO_x limitation.

iii. Steam Generating Unit #3:

- A. Emissions of NO_x shall be no greater than
 - I. 142 lbs/hr on a three (3) hour block average basis, applicable between November 1 and February 28/29.
 - II. 203 lbs/hr on a three (3) hour block average basis, applicable between March 1 and October 31.
- B. Emissions of NO_x shall not exceed
 - I. 168 ppmdv (@ 3% O₂, dry), applicable between November 1 and February 28/29
 - II. 168 ppmdv (@ 3% O₂, dry), applicable between applicable between March 1 and October 31.
- C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

iv. Steam Generating Units #1-3:

- A. The owner/operator shall use only natural gas as a primary fuel and No. 2 fuel oil or better as back-up fuel in the boilers. The No. 2 fuel oil may be used only during periods of natural gas curtailment and for maintenance firings. Maintenance firings shall not exceed one percent of the annual plant Btu requirement. In addition, maintenance firings shall be scheduled between April 1 and November 30 of any calendar year. Records of fuel oil use shall be kept, and they shall show the date the fuel oil was fired, the duration in hours the fuel oil was fired, the amount of fuel oil consumed during each curtailment, and the reason for each firing.
- v. Natural Gas-fired Simple Cycle, Catalytic-controlled Turbine Units:

- A. Total emissions of NO_x from all three turbines shall be no greater than 600 lbs/day. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.
- B. Emissions of NO_x from each turbine stack shall not exceed 5 ppmvd (@ 15% O₂ dry). Emissions shall be calculated on a 30-day rolling average. This limitation applies to steady state operation, not including startup and shutdown.
- C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

- A. Startup begins when the fuel valves open and natural gas is supplied to the combustion turbines
- B. Startup ends when either of the following conditions is met:
 - I. The NO_x water injection pump is operational, the dilution air temperature is greater than 600°F, the stack inlet temperature reaches 570°F, the ammonia block valve has opened, and ammonia is being injected into the SCR and the unit has reached an output of ten (10) gross MW; or
 - II. The unit has been in startup for two (2) hours.
- C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross MW with the intent of removing the unit from service.
- D. Shutdown ends at the cessation of fuel input to the turbine combustor.
- E. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.
- F. Turbine output (turbine load) shall be monitored and recorded on an hourly basis with an electrical meter.

m. Tesoro Refining and Marketing Company, LLC Marathon Refinery: Salt Lake City Refinery

- i. NO_x Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations.

Emission Points	Emission Rate (lb/MMBtu)
A. Crude Unit Furnace H-101	0.054 lb/MMBtu

B. UFU Furnace F-1

0.065 lb/MMBtu

- ii. Initial NO_x stack testing has been performed for the Crude Unit Furnace H-101 and UFU Furnace F-1 and shall be conducted at least once within a three (3) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.
- iii. In lieu of the stack testing requirements listed above, any unit equipped with a CEMs shall determine compliance with the emission limits by the CEMs. For units equipped with CEMs, compliance shall be determined on a 30-day rolling average. The CEMs shall operate as outlined in IX.H.11.f.
- iv. Emissions to the atmosphere from the cogeneration turbines with heat recovery steam generation CG1 and CG2 shall not exceed the following concentration.
 - A. Pollutant ppmdv (15% O₂ dry)
NO_x 32
 - B. Initial NO_x stack testing has been performed and shall be conducted at least once within a two (2) year period from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.
 - C. The above emission limits apply to steady state operations when ambient temperature is between 0 °F and 120 °F, not including startup, shutdown, and minimum power load operations.
 - D. In lieu of the stack testing requirements listed above, any unit equipped with a CEMs shall determine compliance with the emission limits by the CEMs. For units equipped with CEMs, compliance shall be determined on a 30-day rolling average. The CEMs shall operate as outlined in IX.H.11.f.
- v. Cogeneration Unit Startup / Shutdown / Minimum Power Load Emission Minimization Plan
 - A. Startup and shutdown events shall not exceed 614 hours per 12-month rolling period per turbine.
 - B. Cumulative minimum power load operations shall not exceed 421 hours per 12- month rolling period per turbine.
 - C. Startup begins when the fuel valves open and natural gas or fuel gas is supplied to the combustion turbines.
 - D. Startup ends when the following conditions are met:
 - I. The gas temperature is at least 575 °F, and the unit has reached an output of 50% operating load.

- E. Shutdown begins when the unit load or output is reduced below 50% operating load with the intent of removing the unit from service.
 - F. Shutdown ends at the cessation of fuel input to the turbine combustor.
 - G. Minimum Power Load begins when the turbine generator is less than 50% operating load and the heat recovery steam generation unit is no longer supplemental fired, with the intent to continue operation of the turbine generator at minimum power make.
 - H. Minimum Power Load ends when the turbine generator is greater than 50% operating load.
 - I. Turbine output (turbine load) shall be monitored and recorded on an hourly basis with an electrical meter.
- vi. SO₂ emissions from the SRU/TGTU/TGI shall be limited to:
- A. 1.68 tons per day (tpd) for up to 21 days per rolling 12-month period, and
 - B. 0.69 tpd for the remainder of the rolling 12-month period.
 - C. Daily sulfur dioxide emissions from the SRU/TGI/TGTU shall be determined by multiplying the SO₂ concentration in the flue gas by the mass flow of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f
- vii. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	Control Equipment
FCCU / CO Boiler	Wet Gas Scrubber, LoTOx
Furnace F-1	Ultra Low NO _x Burners
Tanks	Tank Degassing Controls
North and South Flares	Flare Gas Recovery
Furnace H-101	Ultra Low NO _x Burners
Truck loading rack	Vapor recovery unit
Sulfur recovery unit	Tail Gas Treatment Unit
Existing API separator	Floating roof (single seal)

- n. The Procter & Gamble Paper Products Company
- i. Emissions to the atmosphere at all times from the indicated emission points shall not exceed the following rates:
 - ii.

Source: Paper Making Boilers (Each)

Pollutant	Oxygen Ref.	lb/hr
NOx	3%	3.3
PM2.5 (Filterable and Condensables)	3%	0.9

Source: Paper Machine Process Stack

Pollutant	Oxygen Ref.	lb/hr
NOX	3%	13.50
PM2.5 (Filterable and Condensables)	3%	17.95

Source: Utility Boilers (Each)

Pollutant	Oxygen Ref.	lb/hr
NOX	3%	1.8
PM2.5 (Filterable and Condensables)	3%	0.74

- A. Compliance with the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP.
- B. Subsequent to initial compliance testing, stack testing is required at a minimum of once every three years.

iii. Boiler Startup/Shutdown Emissions Minimization Plan

- A. Startup begins when natural gas is supplied to the Boiler(s) with the intent of combusting the fuel to generate steam. Startup conditions end within thirty (30) minutes of natural gas being supplied to the boilers(s).
- B. Shutdown begins with the initiation of the stop sequence of the boiler until the cessation of natural gas flow to the boiler.

iv. Paper Machine Startup/Shutdown Emissions Minimization Plan

- A. Startup begins when natural gas is supplied to the dryer combustion equipment with the intent of combusting the fuel to heat the air to a desired temperature for the paper machine. Startup conditions end within thirty (30) minutes of natural gas being supplied to the dryer combustion equipment.

- B. Shutdown begins with the diversion of the hot air to the dryer startup stack and then the cessation of natural gas flow to the dryer combustion equipment. Shutdown conditions end within thirty (30) minutes of hot air being diverted to the dryer startup stack.

o. Utah Municipal Power Association: West Valley Power Plant.

- i. Total emissions of NO_x from all five (5) catalytic-controlled turbines combined shall be no greater than 1050 lb of NO_x on a daily basis. For purposes of this subpart, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.
- ii. Emissions of NO_x shall not exceed 5 ppmdv (@ 15% O₂, dry) on a 30-day rolling average.
- iii. Total emissions of NO_x from all five (5) catalytic-controlled turbines shall include the sum of all periods in the day including periods of startup, shutdown, and maintenance.
- iv. The NO_x emission rate (lb/hr) shall be determined by CEM. The CEM shall operate as outlined in IX.H.11.f.

p. University of Utah: University of Utah Facilities

- i. Emissions to the atmosphere from the listed emission points in Building 303 LCHWTP shall not exceed the following concentrations:

Emissions Point	Pollutant	ppmdv (3% O ₂ dry)
BoilerA#4*		
.B	NO _x	187
Boiler1s)#6 & 7		
.C.B	NO _x	9
Boiler2)#9*		
.C	NO _x	9
Turbin3e)		
.D	NO _x	9
Turbin4e) and WHRU		
Duct burner	NO _x	15

*By December 31, 2019, Boiler #4 will be decommissioned, and Boiler #9 will be installed and operational.

- ii. Stack testing to show compliance with the emissions limitations of Condition i above shall be performed as outlined in IX.H.11.e and as specified below:

Initial test already performed

Emissions Point	Pollutant	Initial Test	Test Frequency *
Boiler #4*			
.B	NOx	*	#
Boilers #6 & 7			
.C	NOx	*	#
Boiler #9*			
.C	NOx	2020	#
Turbine			
.C	NOx	*	#
Turbine and WHRU Duct Burner	NOx	*	#

Initial tests have been performed and the next method test using EPA approved test methods shall be performed within 3 years of the last stack test. Initial compliance testing for Boiler #9 is required. The initial test date shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

A compliance test shall be performed at least once every three years from the date of the last compliance test that demonstrated compliance with the emission limit(s). Compliance testing shall be performed using EPA approved test methods acceptable to the Director. The Director shall be notified, in accordance with all applicable rules, of any compliance test that is to be performed.

- iii. Boiler #4 in the LCHWTP shall be decommissioned and replaced by Boiler #9 by December 31, 2019.
- iv. By the end of the third quarter of calendar year 2019, Boilers #1, #3, and #4 in the UCHWTP shall be limited to a natural gas usage of 530 MMscf per calendar year.
- v. The HSC Transformation Project boilers shall be installed and operational by the end of the third quarter of calendar year 2019. The new HSC Transformation Project boilers shall be equipped with low NOx burners rated at 30 ppmvd at 3% O2 or less.
- vi. Records shall be kept on site which indicate the date, and time of startup and

shutdown.

q. Hill Air Force Base

i. Painting and De-painting Operations

A. VOC emissions from painting and de-painting operations shall not exceed 0.58 tons per day (tpd).

I. No later than the 28th of each month, a rolling 30-day VOC emission average shall be calculated for the previous month.

ii. Boilers

A. The combined NOx emissions for all boilers (except those less than 5 MMBtu/hr) shall not exceed 95 lb/hr. This limit shall not apply during periods of curtailment.

I. No later than the 28th of each month, the NOx lb/hr emission total shall be calculated for the previous month.

B. No later than December 31, 2024, no boiler shall be operating on base with the capacity over 30 MMBtu/hr and with a manufacture date older than January 1, 1989.

H.13 Source-Specific Emission Limitations in Provo – UT PM_{2.5} Nonattainment Area

a. [Brigham Young University: Main Campus]

i. All central heating plant units shall operate on natural gas from November 1 to February 28 each season beginning in the winter season of 2013-2014. Fuel oil may be used as backup fuel during periods of natural gas curtailment. The sulfur content of the fuel oil shall not exceed 0.0015 % by weight. BYU must maintain a fuel specification certification document from the fuel supplier with the sulfur content guarantee. Alternatively, sulfur content may be verified through testing completed by BYU or the fuel supplier using ASTM Method D-4294-10 or EPA approved equivalent acceptable to the Director.

ii. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Emission Point	Pollutant	ppm (7% O ₂ dry)	lb/hr
A. Unit #1	NO _x	95 36 9.55	5.44
B. Unit #4	NO _x	127 36 38.5	19.2
C. Unit #6	NO _x	127 36 38.5	19.2

* Unit #1 NO_x limit is 95 ppm (9.55 lb/hr) until it operates for more than 300 hours during a rolling 12 month period, then the limit will be 36 ppm (5.44 lb/hr). The NO_x limit for units

#4 and #6 is 127 ppm (38.5 lb/hr) and starting on December 31, 2018, the limit will then be 36 ppm (19.2 lb/hr).

Emission Point	Pollutant	ppm (7% O ₂ dry)	lb/hr
D. Unit #2	NO _x	331	37.4
	SO ₂	597	56.0
E. Unit #3	NO _x	331	37.4
	SO ₂	597	56.0
F. Unit #5	NO _x	331	74.8
	SO ₂	597	112.0

iii. Stack testing to show compliance with the above emission limitations shall be performed as follows:

EMISSION POINT	POLLUTANT	INITIAL TEST	TEST FREQUENCY
----------------	-----------	--------------	----------------

A. Unit #1	NO _x	&	every year*
B. Unit #2	NO _x	#	every year*
C. Unit #3	NO _x	#	every year*
D. Unit #4	NO _x	#	every year*
E. Unit #5	NO _x	#	every year*
F. Unit #6	NO _x	#	every year*

& If Unit #1 is operated for more than 100 hours per rolling 12-month period, the stack test shall be performed within 60 days of exceeding 100 hours of operations. Unit #1 shall only be operated as a back-up boiler to Units #4 and #6 and shall not be operated more than 300 hours per rolling 12-month period. If Unit #1 operates more than 300 hours per rolling 12-month period, then low NO_x burners with Flue Gas Recirculation shall be installed and tested within 18 months of exceeding 300 hours of operation.

The test shall be performed at least every 3 years based on the date of the last stack test. Units #4 and #6 shall be retested by March 1, 2018.

* A compliance test shall be performed at least once every three years from the date of the last compliance test that demonstrated compliance with the emission limit(s). Compliance testing shall be performed using EPA-approved test methods acceptable to the Director. The Director shall be notified, in accordance with all applicable rules, of any compliance test that is to be performed. Beginning January 2018, annual screening with a portable monitor must be conducted in those years that a compliance test is not performed. Screening with a portable monitor shall be performed in accordance with the portable monitor manufacturer's specifications. If screening with a portable monitor indicates a potential exceedance of the concentration limit, a compliance test must be performed within 90 days of that screening. Records shall be kept on site which indicate the date, time, and results of each screening and demonstrate that the portable monitor was operated in accordance with manufacturer's specifications.

iv. Central Heating Plant Coal-Fired Boilers

Records shall be kept on site which indicate the date, and time of startup and shutdown.

A. The sulfur content of any coal or any mixture of coals burned shall not exceed either of the following:

1.0.54 pounds of sulfur per million BTU heat input as determined by ASTM Method D-

4239-85, or EPA-approved equivalent acceptable to the Director;

II. 0.60% by weight as determined by ASTM Method D-4239-85, or EPA-approved equivalent acceptable to the Director.

For the sulfur content of coal, Brigham Young University shall either:

III. Determine the weight percent sulfur and the fuel heating value by submitting a coal sample to a laboratory, acceptable to the Director, on no less than a monthly basis; or

IV. For each delivery of coal, inspect the fuel sulfur content expressed as weight % determined by the vendor using methods of the ASTM; or

V. For each delivery of coal, inspect documentation provided by the vendor that indirectly demonstrates compliance with this provision.

v. Central Heating Plant Boilers

A. Records shall be kept on site which indicate the date, and time of startup and shutdown.

b. Geneva Nitrogen Inc.: Geneva Nitrogen Plant

i. Prill Tower:

PM₁₀ emissions (filterable and condensable) shall not exceed 0.236 ton/day
PM_{2.5} emissions (filterable and condensable) shall not exceed 0.196 ton/day

A day is defined as from midnight to the following midnight.

ii. Testing

A. Stack testing shall be performed as specified below:

I. Frequency: Emissions shall be tested every three years. The test shall be performed as soon as possible and in no case later than December 31, 2017.

B. The daily and rolling 12-month mass emissions shall be calculated by multiplying the most recent stack test results by the appropriate hours of operation for each day and for each rolling 12-month period.

iii. Montecatini Plant:

NO_x emissions shall not exceed 30.8 lb/hr

iv. Weatherly Plant:

NO_x emissions shall not exceed 18.4 lb/hr

v. Testing:

A. Stack testing for NO_x shall be performed as specified below:

I. Stack testing to show compliance with the NO_x emission limitations shall be performed as specified below:

1. Testing and Frequency. Emissions shall be tested every three years using an EPA approved test method.

II. NO_x concentration (ppmdv) shall be used as an indicator to provide a reasonable assurance of compliance with the NO_x emission limitation as specified below:

1. Measurement Approach: NO_x concentration (ppmdv) shall be determined by using a continuous NO_x monitoring system.

2. Performance Criteria:

a. QA/QC Practices and Criteria: The continuous monitoring system shall be operated, calibrated, and maintained in accordance with manufacture's recommendations. Zero and span drift tests shall be conducted on a daily basis.

III. The EPA approved method test for the Montecatini Plant shall be performed as soon as possible and in no case later than December 31, 2017, and the test for the Weatherly Plant shall be performed as soon as possible and in no case later than December 31, 2018.

vi. Start up/Shut down

A. Startup / Shutdown Limitations:

I. Planned shut down and start up events shall not exceed 50 hours per acid plant (Montecatini or Weatherly) per 12 month rolling period.

II. Total startup and shutdown events shall not exceed four hours per acid plant in any one calendar day.

c. McWane Ductile – Utah

i. Emissions of VOC from the finishing paint line shall not exceed 1 ton/day.

A. Compliance with the above conditions shall be demonstrated as follows: VOC emissions at the finishing paint line shall be determined by asphalt paint consumption. Asphalt paint consumption shall be monitored by liquid level monitoring sensors on the finishing paint line bulk tanks.

- B. For purposes of this section a day is defined as a period of 24-hours commencing at midnight and ending at the following midnight.
- ii. The Annealing Oven furnaces are limited to ~~[63.29]~~76.5 MMBtu/hr.
- iii. Emissions from the desulfurization and ductile treatment system shall be routed through the operating baghouse prior to be emitted into the atmosphere.
- iv. Emissions from the Special Lining Shotblast operations shall be routed through the operating baghouse prior to being emitted into the atmosphere.
- d. PacifiCorp Energy: Lake Side Power Plant
 - i. Block #1 Catalytic-controlled Turbine/HRSG Stacks:
 - A. Emissions of NO_x shall not exceed 14.9 lb/hr on a 3-hr average basis
 - B. Compliance with the above conditions shall be demonstrated as follows:
 - I.NO_x monitoring shall be through use of a CEM as outlined in IX.H.11.f
 - ii. Block #2 Catalytic-controlled Turbine/HRSG Stacks:
 - A. Emissions of NO_x shall not exceed 18.1 lb/hr on a 3-hr average basis
 - B. Compliance with the above conditions shall be demonstrated as follows:
 - I.NO_x monitoring shall be through use of a CEM as outlined in IX.H.11.f
 - iii. Startup / Shutdown Limitations:
 - A. Block #1:
 - I.Startup and shutdown events shall not exceed 613.5 hours per turbine per 12- month rolling period.
 - II. Total startup and shutdown events shall not exceed 14 hours per turbine in any one calendar day.
 - III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.
 - IV. During periods of transient load conditions, NO_x emissions from the Block #1 Catalytic-controlled Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O₂.

B. Block #2:

- I. Startup and shutdown events shall not exceed 553.6 hours per turbine per 12- month rolling period.
- II. Total startup and shutdown events shall not exceed 8 hours per turbine in any one calendar day.
- III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.
- IV. During periods of transient load conditions, NO_x emissions from the Block #2 Catalytic-controlled Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O₂.

C. Definitions:

- I. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr emission limits listed in IX.H.13.d.i and ii above.
- II. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine.
- III. Transient load conditions are those periods, not to exceed four consecutive 15-minute periods, when the 15-minute average NO_x concentration exceeds 2.0 ppmv dry @

15% O₂. Transient load conditions consist of the following:

1. Initiation/shutdown of combustion turbine inlet air-cooling.
2. Rapid combustion turbine load changes.
3. Initiation/shutdown of HRSG duct burners.
4. Provision of Ancillary Services and Automatic Generation Control.

IV. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

e. ~~Payson City Corporation: Payson City Power~~

i. ~~Emissions of NO_x shall be no greater than 1.54 ton per day for all engines combined.~~

ii. ~~Compliance with the emission limitation shall be determined by summing the emissions from all the engines. Emission from each engine shall be calculated from the following equation:~~

~~Emissions (tons/day) = (Power production in kW hrs/day) x (Emission~~

factor in grams/kW-hr) x (1 lb/453.59 g) x (1 ton/2000 lbs)

A. The NO_x emission factor for each engine shall be derived from the most recent stack test.

Stack tests shall be performed in accordance with IX.H.11.e. Each engine shall be tested at least every three years from the previous test.

B. NO_x emissions shall be calculated on a daily basis.

C. A day is equivalent to the time period from midnight to the following midnight.

D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.

iii. All engines shall be catalytic controlled as outlined in IX.H.11.h.

f. Provo City Power: Power Plant

i. NO_x emissions from the operation of all engines at the plant shall not exceed 2.45 tons per day.

ii. Compliance with the emission limitation shall be determined by summing the emissions from all the engines. Emission from each engine shall be calculated from the following equation:

Emissions (tons/day) = (Power production in kW-hrs/day) x (Emission factor in grams/kW-hr) x (1 lb/453.59 g) x (1 ton/2000 lbs)

A. The NO_x emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.11.e. Each engine shall be tested every 8,760 hours of operation or at least every three years from the previous test, whichever occurs first.

B. NO_x emissions shall be calculated on a daily basis.

C. A day is equivalent to the time period from midnight to the following midnight.

D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.

iii. All engines shall be catalytic controlled as outlined in IX.H.11.h.

g. Springville City Corporation: Whitehead Power Plant

i. NO_x emissions from the operation of all engines at the plant shall not exceed 1.68 tons per day.

ii. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM as outlined in IX.H.11.f. A day is equivalent to the time period from

midnight to the following midnight. Emissions of NO_x shall be calculated for each individual engine by the following equation:

$$D = (X * K) / 453.6$$

Where:

X = grams/kW-hr rate for each generator (recorded by CEM)

K = total kW-hr generated by the generator each day (recorded by output meter)

D = daily output of pollutant in lbs/day

iii. All engines shall be catalytic-controlled as outlined in IX.H.11.h.]

APPENDIX A
Clean Air Act 110(l) Demonstration
Air Quality Impact of Amendments to
Utah State Implementation Plan Section IX.H.12 and IX.H.13

Introduction

Section 110(l) of the Clean Air Act (CAA) states that the Environmental Protection Agency (EPA) cannot approve a state implementation plan (SIP) revision if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress, or any other applicable requirement of the CAA. When revisions to these rules are made, the CAA requires that an analysis is made to verify that the rule will not be relaxed in a way that would be impermissible under Section 110(l).

Additionally, EPA has given draft guidance that “For example, for certain pollutants such as CO, the Agency could determine that an increase in emissions is not interfering with attainment if ambient levels in an attainment area were well below the National Ambient Air Quality Standard (NAAQS) and not trending upward. Under these conditions, the Agency could conclude that ambient levels are so low that a slight emissions increase is not likely to cause a violation of the NAAQS, hence noninterference has been demonstrated (p.12).”¹ The proposed amendments impact such a small number of point source emissions within the PM_{2.5} Maintenance Area that it is not likely to cause a violation.

This demonstration is being submitted for public comment because the Utah Division of Air Quality (UDAQ) is proposing amendments to Utah SIP Section IX.H.12 and Section IX.H.13 to increase one emission limitation for HF Sinclair to align with emissions the source is already emitting, and to increase one limitation for McWane Ductile in Section IX.H.13.

Proposed Amendment Summary

1. HF Sinclair has requested to increase the NO_x emission limitation in Section IX.H.12(g)(i)(A) for the Reformer Reheat Furnace 6H1 from 0.15 lb/MMBtu to 0.20 lb/MMBtu. During the original drafting period of Section IX.H.12(g)(i)(A), HF Sinclair proposed the existing limit on the Reformer Reheat Furnace 6H1 based on best engineering judgement. The Reformer Reheat Furnace 6H1 was constructed in 1957, and due to its age, the source did not have existing vendor emission performance guarantees nor testing data. The unit is currently not equipped with a stack testing port, and has until December 31st, 2028, to install one. Since the final adoption of Section IX.H.12(g)(i)(A), HF Sinclair has conducted engineering NO_x emissions testing using EPA Reference Test Method 19 and determined that the original limit of 0.15 lb/MMBtu is not achievable. Taking into consideration the age of the unit, the new stack testing data, and the original uncertainty the limit was proposed with, UDAQ has agreed with HF Sinclair’s assessment that the limit on the Reformer Reheat Furnace 6H1 should be increased to 0.20 lb/MMBtu.

¹ U.S. Environmental Protection Agency. (2005). *Demonstrating noninterference under Section 110(l) of the Clean Air Act when revising a State Implementation Plan* (Draft).

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Air Quality Impact Analysis: This change results in an additional potential to emit of 11.98 tons per year of NO_x emissions for HF Sinclair, or an additional 0.03 tons per day. Due to this small increase, this change will have no noticeable impact on air quality, air quality modeling for the SIP, or attainment of the PM_{2.5} NAAQS.

When compared to the Attainment Inventory included in the SLC, UT PM_{2.5} Maintenance Plan, UDAQ is confident that the addition of 0.03 tons per day of NO_x emissions will not cause or contribute to a new violation of the NAAQS. Tables 1 through 3 show comparisons to the SLC, UT PM_{2.5} Maintenance Plan emissions inventories. Table 4 shows PM_{2.5} Air Quality Monitor Data Design Values (DV) from 2020 to 2025, showing the 24-hour 98th percentile PM_{2.5} DV averaged over three years. Table 4 indicates that the DV at all monitors within the Maintenance Area, when compared to the 24-hour primary and secondary PM_{2.5} standard of 35 µg/m³ (98th percentile, averaged over three years), have been consistently lower than the NAAQS over the last six years. The monitors are not likely to be influenced by this minor amendment and are predicted to continue to maintain the NAAQS. The levels are low enough that a slight emissions increase is not likely to cause a violation of the NAAQS within the Maintenance Area.

Table 1: Approved Emissions Inventory in SLC, UT PM_{2.5} Maintenance Plan

Approved Emissions Inventory in SLC, UT PM _{2.5} Maintenance Plan		
Emissions (tons/day)	Sector	NO _x
2035	Area Sources	8.69
	Mobile Sources	18.91
	Nonroad Sources	13.32
	Point Sources	22.62
	Total	63.54

Table 2: Revised Emissions Inventory in SLC, UT PM_{2.5} Maintenance Plan

Revised Emissions Inventory in SLC, UT PM _{2.5} Maintenance Plan		
Emissions (tons/day)	Sector	NO _x
2035	Area Sources	8.69
	Mobile Sources	18.91
	Nonroad Sources	13.32
	Point Sources	22.65
	Total	63.57

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Clean Air Act 110(l) Demonstration
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Table 3: Percentage of Total PM_{2.5} Maintenance Plan 2035 NO_x Emissions Projection

Version	NO _x (tons/day)	Full Airshed NO _x Total (tons/day)	Percentage of Total 2035 NO _x Emissions Projection (%)
Approved Emissions	22.62	63.54	35.60%
Revised Emissions	22.65	63.57	35.63%

Table 4: PM_{2.5} values compared to the 24-hour PM_{2.5} NAAQS between 2020-2025

Design Values for the 2006 24-hour PM _{2.5} NAAQS (µg/m ³) – Based on Annual 98 th Percentile							
Monitor Name, County	Monitor ID	2020 24-hr DV (µg/m ³)	2021 24-hr DV (µg/m ³)	2022 24-hr DV (µg/m ³)	2023 24-hr DV (µg/m ³)	2024 24-hr DV (µg/m ³)	2025 24-hr DV (µg/m ³)
Brigham City, Box Elder	49-003-0005	N/A	N/A	N/A	25	23	19
Smithfield, Cache	49-005-0007	31	32	31	34	31	25
Bountiful, Davis	49-011-0004	24	27	29	29	26	22
Copperview, Salt Lake	49-035-2005	31	32	33	32	31	28
Hawthorne, Salt Lake	49-035-3006	26	30	30	30	27	24
Rose Park, Salt Lake	49-035-3010	28	32	33	33	29	24
Herriman, Salt Lake	49-035-3013	24	27	29	28	23	19
Lake Park, Salt Lake	49-035-3014	N/A	N/A	30	28	29	25
Tech Center, Salt Lake	49-035-3015	24	30	33	33	28	25
N. Inland Port, Salt Lake	49-035-3016	N/A	43	36	32	26	21
Red Butte, Salt Lake	49-035-3018	N/A	N/A	N/A	N/A	19	16
Near Road, Salt Lake	49-035-4002	32	34	35	34	32	28
Erda, Tooele	49-045-0004	26	27	28	27	23	20
Lindon, Utah	49-049-4001	25	26	26	24	22	20
Spanish Fork, Utah	49-049-5010	31	24	27	25	22	20
Harrisville, Weber	49-057-1003	25	27	17	26	22	19

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This increase is also unlikely to impact the Northern Wasatch Front's 2015 Ozone Moderate Nonattainment Area (NAA) SIP. Table 5 below demonstrates the 2023 Total Projected Nonattainment Emission Inventory compared to the revised numbers and compares them as a percentage of the total 2023 NO_x Emissions Projection. Table 6 shows Ozone Air Quality Monitor Data from 2020 to 2025, showing the annual fourth-highest daily maximum 8-hour Ozone DV averaged over three years. Table 6 indicates that the design value at the majority of the monitors within an Ozone Nonattainment Area, when compared to the 8-hour primary and secondary Ozone standard of 0.070 ppm (annual fourth-highest daily maximum, averaged over 3 years), have been consistently higher than the NAAQS over the last six years. The monitors are not likely to be influenced by this minor amendment.

This increase is also unlikely to impact the attainment status of any other NAAQS, including Carbon Monoxide (CO), Lead (Pb), Nitrogen Dioxide (NO₂), PM₁₀, and Sulfur Dioxide (SO₂). This amendment will not result in emissions of CO, Pb, PM₁₀, or SO₂, and thus will not impact the attainment status of these pollutants. The entirety of the State of Utah is in attainment for the primary 1-hour NO₂ standard of 100 ppb (annual 98th percentile, averaged over three years). Table 7 shows NO₂ Air Quality Monitor Data from 2020 to 2025, showing the annual 98th percentile 1-hour NO₂ DV averaged over three years. As Table 7 indicates, the design values for all monitors that monitor NO₂ have been consistently lower than the NAAQS over the last six years. The monitors are not likely to be influenced by this minor amendment.

Table 5: Percentage of Total Ozone Moderate SIP 2023 NO_x Emissions Projection

Version	NO _x (tons/day)	Full Airshed NO _x Total (tons/day)	Percentage of Total 2035 NO _x Emissions Projection (%)
Approved Emissions	22.00	87.07	25.27%
Revised Emissions	22.03	87.10	25.29%

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Table 6: Ozone values compared to the 8-hour Ozone NAAQS between 2020-2025.

Design Values for the 2015 8-hour Ozone NAAQS (ppm) – Based on Annual 4 th Highest Daily Maximum							
Monitor Name, County	Monitor ID	2020 8-hr DV (ppm)	2021 8-hr DV (ppm)	2022 8-hr DV (ppm)	2023 8-hr DV (ppm)	2024 8-hr DV (ppm)	2025 8-hr DV (ppm)
Brigham City, Box Elder	49-003-0005	N/A	N/A	N/A	N/A	0.071	0.069
Smithfield, Cache	49-005-0007	0.066	0.066	0.066	0.066	0.066	0.066
Bountiful, Davis	49-011-0004	0.077	0.078	0.079	0.076	0.075	0.075
Roosevelt, Duchesne	49-013-0002	0.073	0.074	0.067	0.077	0.076	0.076
Copperview, Salt Lake	49-035-2005	0.073	0.076	0.078	0.077	0.075	0.074
Hawthorne, Salt Lake	49-035-3006	0.074	0.076	0.076	0.075	0.073	0.073
Rose Park, Salt Lake	49-035-3010	0.077	0.076	0.078	0.074	0.074	0.073
Herriman, Salt Lake	49-035-3013	0.073	0.076	0.077	0.075	0.069	0.069
Lake Park, Salt Lake	49-035-3014	0.062	0.072	0.072	0.075	0.074	0.074
Tech Center, Salt Lake	49-035-3015	0.053	0.063	0.076	0.073	0.071	0.070
N. Inland Port, Salt Lake	49-035-3016	N/A	0.084	0.079	0.077	0.074	0.071
Red Butte, Salt Lake	49-035-3018	N/A	N/A	N/A	N/A	0.081	0.076
Near Road, Salt Lake	49-035-4002	0.068	0.073	0.075	0.077	0.074	0.073
Erda, Tooele	49-045-0004	0.069	0.070	0.071	0.071	0.070	0.068
Vernal, Uintah County	49-047-1004	0.065	0.065	0.064	0.069	0.069	0.071
Lindon, Utah	49-049-4001	0.069	0.069	0.073	0.072	0.071	0.068
Spanish Fork, Utah	49-049-5010	0.069	0.070	0.070	0.069	0.067	0.067
Harrisville, Weber	49-057-1003	0.071	0.071	0.074	0.072	0.071	0.070

APPENDIX A
Clean Air Act 110(l) Demonstration
Air Quality Impact of Amendments to
Utah State Implementation Plan Section IX.H.12 and IX.H.13

Table 7: NO₂ values compared to the 1-hour NO₂ NAAQS between 2020-2025.

Design Values for the 2010 1-hour NO ₂ NAAQS (ppb) – Based on Annual 98th Percentile							
Monitor Name, County	Monitor ID	2020 1-hr DV (ppb)	2021 1-hr DV (ppb)	2022 1-hr DV (ppb)	2023 1-hr DV (ppb)	2024 1-hr DV (ppb)	2025 1-hr DV (ppb)
Brigham City, Box Elder	49-003-0005	N/A	N/A	N/A	N/A	33	34
Smithfield, Cache	49-005-0007	31	32	32	34	33	31
Bountiful, Davis	49-011-0004	45	46	47	49	47	45
Copperview, Salt Lake	49-035-2005	50	49	48	47	46	46
Hawthorne, Salt Lake	49-035-3006	52	52	50	48	47	44
Rose Park, Salt Lake	49-035-3010	48	49	50	49	48	46
Herriman, Salt Lake	49-035-3013	36	34	33	35	35	32
Lake Park, Salt Lake	49-035-3014	47	43	43	42	42	43
Tech Center, Salt Lake	49-035-3015	51	51	51	52	51	49
N. Inland Port, Salt Lake	49-035-3016	N/A	41	42	41	40	39
Red Butte, Salt Lake	49-035-3018	N/A	N/A	N/A	N/A	38	34
Near Road, Salt Lake	49-035-4002	51	49	49	52	50	48
Erda, Tooele	49-045-0004	23	21	20	20	20	18
Lindon, Utah	49-049-4001	42	42	42	41	39	40
Spanish Fork, Utah	49-049-5010	40	38	37	37	38	38
Harrisville, Weber	49-057-1003	43	44	43	42	40	39

2. McWane Ductile has requested to reconstruct their existing annealing oven. A new oven is needed to improve balanced heating of the products, add the ability to control the target temperature of the oven, and improve the thermal penetration in the oven. These changes will increase the existing heat input capacity from 63.29 MMBtu/hr to 76.5 MMBtu/hr.

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Clean Air Act 110(l) Demonstration
Air Quality Impact of Amendments to
Utah State Implementation Plan Section IX.H.12 and IX.H.13

Air Quality Impact Analysis: This change results in the following additional potential to emit for McWane Ductile:

- 0.43 tons per year of PM_{2.5} emissions
- 0.03 tons per year of SO₂ emissions
- 2.84 tons per year of NO_x emissions
- 0.31 tons per year of VOC emissions
- Or an additional total of all direct and precursor PM_{2.5} emissions of approximately 0.01 tons per day

Due to this small increase, this change will have no noticeable impact on air quality, air quality modeling for the SIP, or attainment of the PM_{2.5} NAAQS.

When compared to the Attainment Inventory included in the Provo, UT PM_{2.5} Maintenance Plan, UDAQ is confident that the addition of 0.01 tons per day of total direct and precursor PM_{2.5} emissions will not cause or contribute to a new violation of the NAAQS. The increases in each precursor pollutant category in tons/day are negligible, and less than 0.01 tons per day for each pollutant.

Table 8 shows comparisons to the Provo, UT PM_{2.5} Maintenance Plan emissions inventories. Table 4 above shows PM_{2.5} Air Quality Monitor Data from 2020 to 2025, showing 24-hour Annual 98th percentile PM_{2.5} design value (DV) based on a three-year average. Table 4 indicates that the design values at all monitors within the Maintenance Area, when compared to the 24-hour primary and secondary PM_{2.5} standard of 35 µg/m³ (98th percentile, averaged over three years), have been consistently lower than the NAAQS over the last six years. The monitors are not likely to be influenced by this minor amendment and are predicted to continue to maintain the NAAQS. The levels are low enough that a slight emissions increase is not likely to cause a violation of the NAAQS.

This increase is also unlikely to impact the attainment status of any other NAAQS, including CO, Pb, NO₂, PM₁₀, Ozone, and SO₂. This amendment will not result in emissions of CO or Pb and minimal emissions of PM₁₀ and thus will not impact the attainment status of these pollutants. This increase is unlikely to impact the Southern Wasatch Front's 2015 Ozone Marginal Nonattainment Area. Table 6 above shows Ozone Air Quality Monitor Data from 2020 to 2025, showing the annual fourth-highest daily maximum 8-hour Ozone DV averaged over three years. Table 6 indicates that the design value at the majority of the monitors within an Ozone Nonattainment Area, when compared to the 8-hour primary and secondary Ozone standard of 0.070 ppm (annual fourth-highest daily maximum, averaged over 3 years), have been consistently higher than the NAAQS over the last six years. The monitors are not likely to be influenced by this minor amendment.

APPENDIX A
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The entirety of the State of Utah is in attainment for the primary 1-hour NO₂ standard of 100 ppb (annual 98th percentile, averaged over three years). Table 7 above shows NO₂ Air Quality Monitor Data from 2020 to 2025, showing the annual 98th percentile 1-hour NO₂ DV averaged over three years. As Table 7 indicates, the design values for all monitors that monitor NO₂ have been consistently lower than the NAAQS over the last six years. The monitors are not likely to be influenced by this minor amendment.

The entirety of the State of Utah is also in attainment for the primary 1-hour SO₂ standard of 75 ppb (annual 99th percentile, averaged over three years). Table 9 below shows SO₂ Air Quality Monitor Data from 2020 to 2025, showing the annual 99th percentile 1-hour SO₂ DV averaged over three years. As Table 9 indicates, the design values for all monitors that monitor SO₂ have been consistently lower than the NAAQS over the last six years. The monitors are not likely to be influenced by this minor amendment.

Table 8: Percentage of Total PM_{2.5} (Direct and Precursor Emissions) Maintenance Plan 2035 NO_x Emissions Projection

Version	Total PM _{2.5} (tons/day)	Full Airshed PM _{2.5} Total (tons/day)	Percentage of Total 2035 PM _{2.5} Emissions Projection (%)
Approved Emissions	1.95	48.56	4.02%
Revised Emissions	1.96	48.57	4.03%

Table 9: SO₂ values compared to the 1-hour SO₂ NAAQS between 2020-2025

Design Values for the 2010 1-hour SO ₂ NAAQS (ppb) – Based on Annual 99th Percentile							
Monitor Name, County	Monitor ID	2020 1-hr DV (ppb)	2021 1-hr DV (ppb)	2022 1-hr DV (ppb)	2023 1-hr DV (ppb)	2024 1-hr DV (ppb)	2025 1-hr DV (ppb)
Copperview, Salt Lake	49-035-2005	3	3	3	3	3	3
Tech Center, Salt Lake	49-035-3015	4	4	4	5	5	5
Hawthorne, Salt Lake	49-035-3006	4	4	4	4	4	4
Rose Park, Salt Lake	49-035-3010	5	6	6	6	5	4

APPENDIX A
Clean Air Act 110(l) Demonstration
Air Quality Impact of Amendments to
Utah State Implementation Plan Section IX.H.12 and IX.H.13

Conclusion: The proposed amendments to Part IX.H.12 and IX.H.13 will not impact the area's ability to maintain the NAAQS for any pollutant. The UDAQ is confident that increasing HF Sinclair's Reformer Reheat Furnace 6H1 emission limit and increasing the maximum heat input capacity for McWane Ductile's Annealing Oven will not result in a noticeable increase in overall emissions in the Salt Lake and Utah County airsheds. For the PM_{2.5} Maintenance Area, the monitors in the Maintenance Area are not likely to be influenced by the minor amendments and are predicted to continue to maintain the PM_{2.5} NAAQS. The ambient levels are so low that a slight emissions increase is not likely to cause a violation of the NAAQS, hence noninterference has been demonstrated. For the Ozone Nonattainment Areas, the monitors in the Nonattainment Areas are not likely to be influenced by the minor amendment and are predicted to continue to be consistently higher than the Ozone NAAQS. The ambient levels are so low that the slight emissions increase will not cause a new violation of the Ozone NAAQS, hence noninterference has been demonstrated.

ITEM 5



State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-008-26

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

THROUGH: Jazmine Lopez, Rules Coordinator

FROM: Tasnuva Islam, Environmental Scientist

DATE: March 18, 2026

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend Section R307-110-11 to incorporate Utah State Implementation Plan Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide; Section IX.B.11, SO₂ Maintenance Provisions for Salt Lake County Nonattainment Area and Section IX.B.12, SO₂ Maintenance Provisions for Tooele County Nonattainment Area.

The Utah Division of Air Quality has prepared a revision to the Utah State Implementation Plan (SIP), Section IX.B.11 establishing a comprehensive SO₂ Maintenance Plan for Salt Lake County Nonattainment Area and Section IX.B.12 for Tooele County Nonattainment Area (eastern portion above 5,600 feet in elevation). This SIP revision is submitted pursuant to Sections 107(d)(3)(E) and 175A of the Clean Air Act (CAA) and is intended to support Environmental Protection Agency (EPA) redesignation of the areas from nonattainment to attainment for the 1971 SO₂ National Ambient Air Quality Standards (NAAQS).

Salt Lake County and portions of Tooele County were originally designated nonattainment in 1978 due to violations of the 1971 primary 24-hour standard of 0.14 parts per million (ppm) and secondary 3-hour standard of 0.5 ppm, primarily associated with emissions from the Kennecott copper smelter. Following implementation of federally enforceable control measures beginning with the 1981 SO₂ SIP and strengthened through subsequent revisions to the SO₂ SIP in 1991 and 1992 and PM₁₀ SIP related controls, monitored SO₂ concentrations declined dramatically. The area has recorded no violations of the 1971 SO₂ NAAQS since 1981.

The Maintenance Plans documents that the areas have attained the 1971 primary (annual and 24-hour) and secondary (3-hour) SO₂ standards, based on more than four decades of quality-assured monitoring data.

This attainment is the result of permanent and enforceable emission reductions, including modernization of smelting operations, installation of advanced sulfur capture technology, enforceable emission caps, and strengthened fuel sulfur limits. The plans note that updated dispersion modeling conducted by Ramboll using EPA-approved AERMOD procedures and conservative allowable emission limits demonstrates continued compliance with all three 1971 standards throughout the nonattainment areas. In addition, emissions inventories and projections indicate that current and future allowable emissions will provide a substantial compliance margin through the maintenance period of 2040.

The Maintenance Plans include all elements required under CAA Section 175A, including an attainment inventory, projected future-year inventory, verification of continued monitoring, commitment to submit revised maintenance plans, continued implementation of the nonattainment area control strategies, and contingency measures that ensure prompt corrective action in the unlikely event of a future violation.

Recommendation: Staff recommend the Board approve the amendment to Section R307-110-11 to incorporate Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide; Utah State Implementation Plan, Section IX.B.11, SO₂ Maintenance Provisions for Salt Lake County Nonattainment Area and Section IX.B.12, SO₂ Maintenance Provisions for Tooele County Nonattainment Area, for a 30-day public comment period.

State of Utah
Administrative Rule Analysis
Revised May 2025

NOTICE OF SUBSTANTIVE CHANGE

TYPE OF FILING: Amendment

Rule or section number:

R307-110-11

Filing ID: OFFICE USE ONLY

Date of previous publication (only for CPRs):

Agency Information

1. Title catchline:	Environmental Quality, Air Quality	
Building:	Multi-Agency State Office Building	
Street address:	195 N 1950 W	
City, state:	Salt Lake City, UT	
Mailing address:	PO Box 144820	
City, state and zip:	Salt Lake City, UT 84114-4820	
Contact persons:		
Name:	Phone:	Email:
Tasnuva Islam	801-536-0076	tislam@utah.gov
Jazmine Lopez	801-536-4050	jazminelopez@utah.gov

Please address questions regarding information on this notice to the persons listed above.

General Information

2. Rule or section catchline:	
R307-110-11. Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide.	
3. Are any changes in this filing because of state legislative action?	Changes are not because of legislative action.
If yes, any bill number and session:	
4. Purpose of the new rule or reason for the change:	
The Utah Air Quality Board has proposed for public comment amendments to Utah State Implementation Plan (SIP), Section IX, Part B. The amendments to the SIP add plans that demonstrate maintenance of all three 1971 SO ₂ National Ambient Air Quality Standards (NAAQS) through the year 2040 for the Salt Lake County Nonattainment Area (SLC NAA) and Tooele County Nonattainment Area (TC NAA). Section R307-110-11 incorporates Section IX, Part B into the rule, and must be amended to change the Board adoption date to the anticipated date of the amended plan.	
5. Summary of the new rule or change:	
This rule amendment incorporates a SIP revision establishing maintenance plans for the 1971 SO ₂ NAAQS for the SLC NAA and the TC NAA. The maintenance plans demonstrate continued attainment of the standard in the applicable area and fulfil the requirements of Section 175A of the Clean Air Act. If EPA approves the plans, the nonattainment areas will be redesignated to attainment status. Section R307-110-11 Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide is being amended to change the Board adoption date to the anticipated date of the amended plan.	

Fiscal Information

6. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:
A. State budget:
This amendment is not expected to have any fiscal impact on the state budget because the plan being incorporated into the rule shows how already existing regulations have led to attainment of the 1971 SO ₂ air quality standards. This amendment does not alter current regulations or practices.
B. Local governments:
This amendment is not expected to have any fiscal impact on local governments because this amendment does not apply to local governments.
C. Small businesses ("small business" means a business employing 1-49 persons):

This amendment is not expected to have any fiscal impact on small businesses because this amendment does not apply to small businesses.

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

This amendment is not expected to have any fiscal impact on non-small businesses because this amendment does not apply to 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 amendment is not expected to have any fiscal impact on persons other than small businesses, non-small businesses, state, or local government entities because this amendment does not apply to persons other than small businesses, non-small businesses, state, or local government entities.

F. Compliance costs for affected persons:

This amendment will not have compliance costs for affected persons because the plan being incorporated into the rule shows how already existing regulations have led to attainment of the 1971 SO2 air quality standards. This amendment does not alter current regulations or practices.

G. Regulatory Impact Summary Table (This table includes only fiscal impacts the agency was able to measure. If the agency could not estimate an impact, it is excluded from this table but described in boxes A through F.)

Regulatory Impact Summary Table					
Fiscal Cost	FY2026	FY2027	FY2028	FY2029	FY2030
State Budget	\$0	\$0	\$0	\$0	\$0
Local Governments	\$0	\$0	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0	\$0	\$0
Other Persons	\$0	\$0	\$0	\$0	\$0
Total Fiscal Cost	\$0	\$0	\$0	\$0	\$0
Fiscal Benefits	FY2026	FY2027	FY2028	FY2029	FY2030
State Budget	\$0	\$0	\$0	\$0	\$0
Local Governments	\$0	\$0	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0	\$0	\$0
Other Persons	\$0	\$0	\$0	\$0	\$0
Total Fiscal Benefits	\$0	\$0	\$0	\$0	\$0
Net Fiscal Benefits	\$0	\$0	\$0	\$0	\$0

H. Department head comments on fiscal impact and approval of regulatory impact analysis:

The Executive Director of the Department of Environmental Quality, Tim Davis, has reviewed and approved this regulatory impact 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:

Section 19-2-104	42 U.S.C 85 Part D Section 7505a	

Incorporation by Reference Information

8. Incorporation by Reference (if this rule incorporates more than two items by reference, please include additional tables):

A. This rule adds or updates the following title of material incorporated by reference (a copy of the material incorporated by reference must be submitted to the Office of Administrative Rules. *If none, leave blank*):

Official Title of Materials Incorporated (from title page)	Utah State Implementation Plan Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide.
---	---

Publisher	Division of Air Quality, Utah Department of Environmental Quality
Issue Date	July 1, 2026
Issue or Version	

B. This rule adds or updates the following title of material incorporated by reference (a copy of the material incorporated by reference must be submitted to the Office of Administrative Rules. *If none, leave blank*):

Official Title of Materials Incorporated (from title page)	
Publisher	
Issue Date	
Issue or Version	

Public Notice Information

9. The public may submit written or oral comments to the agency identified in box 1.

A. Comments will be accepted until: 05/15/2026

B. A public hearing (optional) will be held (The public may request a hearing by submitting a written request to the agency, as outlined in Section 63G-3-302 and Rule R15-1.):

Date:	Time (hh:mm AM/PM):	Place (physical address or URL):
05/05/2026	03:00PM - 04:00PM	A public hearing is set for May 5, 2026. Further details may be found below. The hearing will be cancelled should no request for one be made by May 1, 2026, at 10 AM MT. The final status of the public hearing will be posted on May 1, 2026, after 10 AM MT. The status of the public hearing may be checked at the following website location under the corresponding rule. https://deq.utah.gov/public-notices-archive/air-quality-rule-plan-changes-open-public-comment Interested Persons can participate in person or electronically, via the internet. In Person: MASOB 195 N. 1950 W. Salt Lake City, UT, 84116, First Floor, Air Quality Board Room Virtual Attendance: Time zone: America/Denver Google Meet joining info: Video call link: https://meet.google.com/amj-xjne-yqq Or dial: (US) +1 406-616-2412 PIN: 335 196 879#

To the agency: If more than one hearing is planned to take place, continue to add rows.

10. This rule change MAY become effective on: 07/01/2026

NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date.

Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 63G-3-302, 63G-3-303, and 63G-3-402. The office may return incomplete forms to the agency, 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, Division of Air Quality	Date:	03/12/2026
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R307. Environmental Quality, Air Quality.

R307-110. General Requirements: State Implementation Plan.

R307-110-11. Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide.

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide, as most recently amended by the Utah Air Quality Board on ~~January 5, 2005~~ **July 1, 2026**, 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: ~~July 2, 2025~~ 2026

Notice of Continuation: December 1, 2021

Authorizing, and Implemented or Interpreted Law: 19-2-104

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5 UTAH STATE IMPLEMENTATION PLAN

6 **SO₂ Maintenance**
7 **Provisions for the Salt Lake**
8 **County, UT SO₂ Nonattainment Area**
9

10 SECTION IX.B.11
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Section IX.B.11 SO₂ Maintenance Provisions for Salt Lake County

IX.B.11.a Introduction

In 1978, the U.S. Environmental Protection Agency (EPA) designated three areas in Utah as nonattainment for the 1971 National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO₂). At that time, the EPA had established three SO₂ standards: a 24-hour primary standard, an annual primary standard, and a 3-hour secondary standard. The three nonattainment areas were:

- Cedar City Nonattainment Area;
- Salt Lake County Nonattainment Area (SLC NAA); and
- Tooele County Nonattainment Area (TC NAA)¹

The EPA approved Utah's SO₂ control strategy for Cedar City on February 19, 1980. However, the strategy for SLC NAA and TC NAA was disapproved. In 1981, Utah submitted a revised SO₂ State Implementation Plan (SIP) for the two counties, which included a redefined nonattainment boundary covering all of Salt Lake County and only the eastern portion of Tooele County above 5,600 feet in elevation.

The EPA granted interim approval of this SIP in 1985, pending resolution of issues related to Good Engineering Practice (GEP) stack height requirements. To address this, Utah submitted its GEP SIP in 1986, followed by additional submittals in 1986, 1987, and 1988. The EPA proposed approval of the GEP SIP in 1988, but final approval was delayed due to public comments, particularly concerning land ownership on elevated terrain, which affected the GEP stack height demonstration.

With the 1990 amendments to the Clean Air Act (CAA), any nonattainment area lacking a fully approved SIP was automatically redesignated as nonattainment and subject to a SIP call. Because the Utah SIP had never received full approval, the State was once again required to submit revised SIPs addressing both:

- GEP stack height; and
- SO₂ control measures.

All other areas in Utah, including Cedar City, were found to have ambient air quality that was "better than the national standards" and thus did not require further SIP revisions. There have been no violations of either the primary or secondary NAAQS for SO₂ in the Utah nonattainment areas since 1981. The lack of monitored violations is the result of permanent and enforceable

¹ A portion of the county is located within the area and is designated nonattainment
<https://www3.epa.gov/airquality/greenbook/snacs.html#UT>

1 emission reductions at the emissions points that were responsible for the violations which led to
2 the original nonattainment status.

3
4 Based on this long-standing compliance and in accordance with the CAA Section 107(d)(3)(D),
5 Utah submitted the required SIP revisions in 1991 (for GEP stack height) and 1992 (for SO₂
6 control). The EPA approved both in 1994, bringing Salt Lake County and Tooele County into
7 compliance with federal requirements.

8
9 Salt Lake County and Tooele County have attained the 1971 SO₂ standards. As a result, this
10 section has been added to the SIP to demonstrate that the area is eligible for redesignation to
11 attainment. Under Section 107(d)(3)(E) of the CAA, a nonattainment area is eligible for
12 redesignation when the area has met the following requirements: (1) the area has attained the
13 NAAQS standard; (2) the area has an EPA-approved attainment SIP; (3) the improvement in air
14 quality is due to permanent and enforceable reductions in emissions resulting from
15 implementation of the SIP; (4) the State has met the SIP requirements of Section 110 and Part D
16 of the CAA; and (5) the area has an EPA-approved Maintenance Plan.

17
18 As demonstrated in Subsection IX.B.11.c, the nonattainment area has satisfied the redesignation
19 requirements of Section 107 and is eligible for redesignation pending the EPA's approval of the
20 Salt Lake County Maintenance Plan. The maintenance plan is included in Subsection IX.B.11.d
21 and is written in compliance with Section 175A of the CAA. The maintenance plan demonstrates
22 that the nonattainment area will continue to maintain the 1971 NAAQS through 2040. The
23 maintenance plan also includes contingency measures to assure that the State will promptly
24 correct any violation of the standard that may occur after the redesignation. In addition to EPA's
25 approval of the maintenance plan, the State is requesting that the SLC NAA be redesignated to
26 attainment for the 1971 SO₂ NAAQS.

27 IX.B.11.b History of Nonattainment Area Designation

28 Since the SO₂ nonattainment designations occurred at the same time and involved similar
29 regulatory decisions and control strategies by the EPA and the State, Section IX.B.11.b includes
30 discussion of all three areas to provide historical context and a complete description of Utah's
31 SO₂ SIP development. Although this maintenance plan applies specifically to the SLC NAA, the
32 Tooele County and Cedar City areas are referenced because they were addressed concurrently in
33 the State's early SO₂ SIP submittals.

1 i) The 1981 SO₂ SIP Submittal

2 In the Federal Register dated March 3, 1978, there were three areas in Utah that were designated
3 as nonattainment for the 1971 SO₂ NAAQS.² These three areas include:

- 4 • SLC NAA;
- 5 • TC NAA; and
- 6 • Cedar City.

7 All three areas were violating the primary 24-hour SO₂ standard of 0.14 parts per million (ppm)
8 not to be exceeded more than once per year, in addition to the secondary 3-hour standard of 0.5
9 ppm not to be exceeded more than once per year. There have not been any recorded violations of
10 the primary annual standard of 0.03 ppm. The designation of Cedar City as a nonattainment area
11 for SO₂, made by the State, was based on ambient air quality data collected at the State's
12 monitoring station on the campus of Southern Utah State College (now Southern Utah State
13 University).³ The designation recommendations of Salt Lake and Tooele counties made by the
14 State were overrode by the EPA, based on data collected at the State's ambient air monitoring
15 stations in Magna and Tooele.²

16
17 The old reverberatory furnace system at the Kennecott Copper Corporation's Utah Smelter
18 (Kennecott) was still in operation at that time. On March 13, 1981, the EPA revised Tooele
19 County's nonattainment designation to include only areas above 5,600 feet in elevation. The
20 primary focus of the 1981 SIP for Salt Lake and Tooele counties, supported by both the State and
21 the EPA, was to control emissions from Kennecott's operations.

22
23 On August 17, 1981, the Governor submitted a revision to the SIP to address the attainment of
24 the SO₂ NAAQS in Salt Lake County and Tooele County. Additional supporting documents
25 were submitted by the State on December 7, 1981, and January 25, 1983. The primary control
26 measure in the SIP for Salt Lake and Tooele counties was the construction of a new smelter at
27 Kennecott to replace the old reverberatory furnace system. The only control measure in the SIP
28 for Cedar City was enforcement of the existing limitation for sulfur content in fuel oil used at
29 Southern Utah State College. In December of 1983, Cedar City was redesignated as an
30 attainment area for SO₂.⁴

² Utah SO₂, Salt Lake and Tooele counties and Cedar City do not meet primary and secondary SO₂ standards,
https://archives.federalregister.gov/issue_slice/1978/3/3/8907-9023.pdf#page=58, See Page 9039.

³ Utah State Implementation Plan, August 16, 1981, Section 9, Part B, Figure 9.B.1.

⁴ Utah Air Conservation Rule R307-1-4.2.

1 On February 7, 1983, the Governor formally requested that the SLC NAA and TC NAA be
2 redesignated to attainment. However, on March 23, 1984, the EPA proposed to postpone any
3 action on the redesignation request until several outstanding issues were resolved.⁵

4 ii) Control Strategies for Nonattainment Area

5 A careful review of the emissions inventory and diffusion modeling that was coordinated by the
6 State indicated that the emissions from one point source, Kennecott Copper Corporation, resulted
7 in violations of the 1971 NAAQS for SO₂ which were observed in both counties.

8
9 Ambient measurements taken by the Department of Health in Salt Lake County indicated that the
10 NAAQS were violated only at the site in Magna, Utah. Based on this information, the Magna
11 monitoring site was used as the control point for development of the control plan. No violations
12 of the 1971 NAAQS have been observed at any of the monitoring stations since 1980. As part of
13 the 1981 SIP,⁶ the State adopted revised emission limitations and control requirements for the
14 following Kennecott operations:

- 15 • Smelter Main Stack;
- 16 • Fugitive Emissions;
- 17 • Power Plant Boilers;
- 18 • Molybdenite Heat Treaters; and
- 19 • Refinery.

20 The power plant boilers, heat treaters, and refinery were required to meet constant emission
21 limitations. The fugitive emissions were controlled by application of “best engineering
22 techniques.”

23 The main stack, which accounted for 88% of the total emissions, was controlled by a variable
24 emission limitation. The main stack limits contained the following key elements:

- 25 • annual average emission limit of 18,200 pounds per hour (lbs/hr);
- 26 • cumulative occurrence limits at specified frequencies and 3-hour running average
27 emission rates; and
- 28 • a maximum 3-hour emission limit of 98,400 lbs/hr never to be exceeded.

29 These emission limitations were developed using the multipoint rollback (MPR) approach and
30 represented a 10% reduction from the allowable emissions under the previous state regulation. A
31 federally promulgated regulation specific to Kennecott had established a 6,030 lbs/hr emission
32 limit for the main stack and required the implementation of reasonably achievable control

⁵ Approval and Promulgation of State Implementation Plans Designation of Areas for Air Quality Planning Purposes, Utah Sulfur Dioxide Plan, March 23, 1984, 49 FR 10946.

⁶ Utah SO₂ SIP, <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=612086&dbid=0>.

1 technology (RACT) for fugitive emissions.⁷ However, in response to petitions for
2 reconsideration and legal challenges to that regulation, the EPA agreed in 1977 not to enforce
3 these limits.

4 iii) State Attainment Demonstration

5 The 1981 SO₂ SIP demonstration only addressed the attainment of NAAQS in the lower
6 elevations and did not address the elevated terrain. Instead, the State took the position that these
7 higher elevation areas did not constitute “ambient air” under the definition provided in 40 CFR
8 50.1(e), as they are not accessible to the general public.⁸

9
10 The State employed several methods in developing the proposed emission limitations and in
11 demonstrating that the SIP would provide a reasonable probability of attaining the NAAQS in
12 lower elevation areas. These methods included:

- 13 • analysis of measured violations in Magna, Utah, and at the Great Salt Lake Beach,
14 including identification of the causes of those violations;
- 15 • calibrated dispersion modeling estimates to predict SO₂ concentrations in the lower
16 elevations before and after implementation of the SIP;
- 17 • qualitative analysis of the impacts of fugitive emissions at the Great Salt Lake Beach and
18 the improvements expected as a result of the SIP; and
- 19 • MPR for the development of the variable emission limitations at the main stack.

20 EPA's Review of State Attainment Demonstration

21 (1) Elevated Terrain

22 Historically, the EPA has applied the regulatory definition of “ambient air” in such a way that if
23 public access were precluded such as by a fence or other physical barrier, then air over property
24 owned or controlled by a source is not considered “ambient air” and therefore not subject to
25 NAAQS. This policy is reflected in the November 26, 1975, EPA rulemaking affecting the
26 Kennecott main stack emission limits.⁹ The EPA proposed that documentation and representation
27 made by Kennecott adequately demonstrate that the company had taken reasonable and effective
28 precautions to limit general public access to company property, and thus the company property
29 in the elevated terrain is not “ambient air.” Public comments on EPA’s final rulemaking were
30 pending and under review.

⁷ Standards of Performance for Primary Copper Smelters, 42 FR 37937, July 25, 1977, and 40 CFR 60.160.
www.govinfo.gov/content/pkg/FR-1977-07-25/pdf/FR-1977-07-25.pdf.

⁸ Definitions: 40 CFR 50.1(e), [www.ecfr.gov/current/title-40/part-50/section-50.1#p-50.1\(e\)](http://www.ecfr.gov/current/title-40/part-50/section-50.1#p-50.1(e)).

⁹ Rules and Regulations 40 FR 54788, www.govinfo.gov/content/pkg/FR-1975-11-26/pdf/FR-1975-11-26.pdf.

(2) SO₂ Control Strategy for Main Stack

The strategy developed by the State for the main stack was derived from a general approach known as MPR. The MPR approach is designed to accommodate the highly variable SO₂ emissions produced by smelters and produces a cumulative frequency distribution of allowed emission rates. Emission limits are developed by cumulative distribution of observed emission rates and air quality measurements over an extended period of time, usually a year or more. The SIP includes specific emission limitations for the low-level sources as well as a multipoint limit for the main stack. The mission limits included in the 1981 SO₂ SIP were:

Table 1: 1981 SO₂ SIP Limits

Source	Emission Limit
Power Plant Boilers	0.48 lbs/MMBtu
Molybdenite Heat Treaters	139 lbs/hr
Refinery	117 lbs/hr
Fugitive Emissions	RACT
Main Stack - Annual Average	18,200 lbs/hr
Main Stack - 3 Hour Maximum	98,400 lbs/hr

In the State's attainment demonstration, the design value (DV) for the MPR was a calculated 3-hour concentration of 0.46 ppm in lower elevations as compared to the 1971 NAAQS of 0.50 ppm. As the DV is less than the standard, this allowed an 8.7% increase in allowable emissions from the base period. The result was an allowable annual average stack emission rate calculated to be 18,200 lbs/hr.¹⁰ During the technical review of the control strategy, the EPA identified the following technical deficiencies and enforcement issues:

To develop the MPR, the State used a supplemental control system (SCS) during the period of record, which violates the basic principle of the MPR equation that emissions and dispersion are independent. At this time, no other acceptable alternate data was available to develop emission limits for the Kennecott smelter.

- In DV selection, the State used the second highest of the discrete 3-hour average instead of the highest one-per-year maximum concentrations.
- The State-proposed regulations required continuous emission monitors (CEM) to operate at least 95% of the time in each one-month period. However, the regulation did not limit the duration of a single breakdown.¹¹

¹⁰ Utah State Implementation Plan, Section 9 Part B.3.c., Development of the 3-hour Tall Stack Emission Limit, May 15, 1992.

¹¹ Utah State Implementation Plan, Section 4.3.2., Regulation for Control of Main Stack SO₂ Emissions (Kennecott Mineral Company), August 16, 1981.

- The State-proposed regulations did not outline the procedure to follow when determining which CEM data is 20% or more in error. The regulation also gave the smelter the option to delete or retain such data.¹²

The EPA conducted additional analysis on the development of MPR and the selection of DV and concluded that the strategy for the Kennecott main stack should not jeopardize attainment and maintenance of the SO₂ NAAQS in the lower elevations.¹³

Per the enforcement issues, the EPA proposed revisions of the rules to include provisions both limiting individual monitor downtime and providing incentives to strive for 100% CEM data recovery. Additionally, the EPA proposed to incorporate 40 CFR Part 60, Appendix B Part 2 of the quality assurance requirements.¹⁴ The SIP was conditionally approved given the above-mentioned issues were addressed prior to final rulemaking. At this stage, public comments on EPA's final rulemaking were still under review.

(3) Low-Level Source Issues

During the winter of 1979 and 1980, there were five measured violations of the 24-hour standard of 0.14 ppm in Magna. In addition, during the winter of 1981 there were two measured violations of the same standard at the Beach monitor located near the smelter. The highest concentration at the site was 0.19 ppm. As a result of these observed violations, the State's control strategy was to demonstrate attainment at these receptors. Several studies conducted in the area attributed the violations to low-level fixed stack sources and fugitive emissions. The low-level emissions inventory for the non-fugitive sources from this time period are shown below:

Table 2: Emissions inventory of non-fugitive sources

Source	Emissions (lbs/hr)	
	1979	1983
Magna Heat Treater	454	136
Arthur Heat Treater	454	136
Refinery	354	103
Boiler	714	828
Boilers	375	401
Total	2,351	1,604

¹² Utah State Implementation Plan, Section 4.3.2., Regulation for Control of Main Stack SO₂ Emissions (Kennecott Mineral Company), August 16, 1981.

¹³ Approval and Promulgation of State Implementation Plans, 40 CFR Part 52 and 40 CFR Part 81.

¹⁴ Approval and Promulgation of State Implementation Plans, 40 CFR Part 52 and 40 CFR Part 81.

1 The State required a 70% emission reduction from the smelter's low-level sources and required
2 improved fugitive emission capture practices at the smelter. The effectiveness of the control
3 strategy was demonstrated via modeling efforts by the State. The modeling estimate predicted
4 attainment of the SO₂ standards by December 1982. EPA conducted an independent modeling
5 effort to verify the State's findings and determined that the results agreed with the State's result
6 at Magna, but the Beach monitor showed some variability.

7
8 Since the fugitive emissions and the reduction expected by December 1982 could not be reliably
9 quantified, the State submitted information on January 25, 1983, which described the control
10 practices on fugitive emissions implemented at the smelter since the 1981 violations and
11 included a qualitative analysis of the expected effects of those practices. The State's conclusions
12 regarding attainment of the standards in the vicinity have been substantiated by measured data
13 since 1981. Based on this information, the EPA ruled in favor of the State's control strategy for
14 the low-level sources to attain and maintain the SO₂ standards in lower elevations.

15 (4) Stack Height Credit

16 Under the 1982 stack height regulations,¹⁵ stack height credit can be calculated in the following
17 three methods¹⁶: (1) de minimis height (stack less than 65 meters); (2) mathematical formulas; or
18 (3) physical demonstrations. The State calculated its GEP stack height according to a fluid
19 modeling demonstration. The demonstration did not fully comply with EPA's 1982 regulations¹⁷
20 because no specific percentage of increased concentrations was measured. However, based on
21 the best engineering judgment of EPA technical staff, the source apparently could demonstrate at
22 least a 40% increase in concentrations using the approach in the 1982 regulations. Due to the
23 GEP regulation being under litigation and its uncertain status¹⁸, EPA concluded that it would be
24 futile to require the source to perform additional fluid modeling demonstrations based on the
25 1982 regulations.

26 iv) 1985 Interim SO₂ SIP Approval

27 On February 20, 1985, EPA proposed interim approval of the 1981 SIP on the condition that the
28 State of Utah agreed to satisfy all procedural and substantive requirements of the stack height
29 regulations once any further regulations were promulgated or the existing regulations were

¹⁵ Stack height Regulations, February 8, 1982, 47 FR 5864, www.govinfo.gov/content/pkg/FR-1982-02-08/pdf/FR-1982-02-08.pdf.

¹⁶ Method of Determining GEP Stack Height, February 8, 1982, 47 FR 5865, www.govinfo.gov/content/pkg/FR-1982-02-08/pdf/FR-1982-02-08.pdf.

¹⁷ Stack height Regulations, February 8, 1982, 47 FR 5864, www.govinfo.gov/content/pkg/FR-1982-02-08/pdf/FR-1982-02-08.pdf.

¹⁸ Sierra Club vs. EPA, 719 F.2d 436, www.casemine.com/judgement/us/5914c378add7b049347c6b6f.

upheld on appeal.¹⁹ For the final approval of the SIP, the State was required to promulgate additional SIP provisions committing to the following actions:

- In the event EPA promulgates new regulations with requirements different from those in the 1982 regulations, the State of Utah will, within nine months of such promulgation, submit a demonstration of the GEP stack height under the new regulations and, based on that demonstration, submit either: (a) a demonstration that the SIP adequately assures attainment when that height is taken into account; or (b) a SIP revision demonstrating attainment.
- In the event the 1982 regulations are upheld on appeal, the State will submit a new fluid modeling study meeting the requirements of those regulations within nine months of the decision.

v) 1986 GEP Stack Height SIP Submittal

The Utah GEP Stack Height SIP was submitted by the Governor in a letter dated May 2, 1986.²⁰ The submittal included regulations to address:

- GEP stack height credit and dispersion techniques;
- a new Section 17 of the SIP that listed all existing stacks in Utah greater than 65 meters; and
- a technical support document for Section 17 including the Kennecott Magna stack analysis.

The Kennecott stack height credit was a significant component of the Utah SO₂ SIP emission limits conditionally approved on February 20, 1985.

vi) Applicability of the NSPS Regulation

The federal New Source Performance Standards (NSPS) regulation for primary copper smelters (40 CFR 60 NSPS Subpart P) applies to any such facility that commences construction or modification after October 16, 1974.^{21, 22} Modification generally means any physical or operational changes which results in an increase in the emission rate to the atmosphere.

The Kennecott smelter expansion/modification began in the early 1970's, with a commitment to the 1,215-foot stack in 1973 and completion of the project in 1977. The acid plant system resulted in an increase from 60% sulfur capture to 86%, reducing sulfur emissions by

¹⁹ Approval and Promulgation of State Implementation Plans – Utah SO₂ Plan, February 20, 1985, 50 FR 7059, www.govinfo.gov/content/pkg/FR-1985-02-20/pdf/FR-1985-02-20.pdf.

²⁰ Utah SIP, Section XVIII, Demonstration of GEP Stack Height, May 2, 1986.

²¹ Standards of performance for Primary Copper Smelters, 42 FR 37937, July 25, 1977; www.govinfo.gov/content/pkg/FR-1977-07-25/pdf/FR-1977-07-25.pdf.

²² Applicability and designation of affected facility, 40 CFR 60.160, www.ecfr.gov/current/title-40/section-60.160.

1 approximately 65%. Based on this information, the EPA concluded that the 1970's Kennecott
2 expansion/modification did not subject the smelter to 40 CFR 60 NSPS Subpart P requirements.

3 **vii) Analyses of the Stack Height SIP Submittal**

4 The Kennecott stack height analyses were undertaken to comply with the July 8, 1985, stack
5 height regulations, as well as the conditions specified in the approval of the Utah SO₂ SIP.²³
6 Kennecott originally had two 400-foot stacks (grandfathered stack height) from which SO₂
7 emissions from the smelter were vented. The 1970's expansion/modification included the
8 replacement of the two 400-foot stacks with a single 1,215-foot stack. The GEP formula height
9 ($H + 1.5 L$), considering the nearby buildings, is 212.5-foot.

10
11 The initial Kennecott GEP demonstration was submitted on May 2, 1986, with subsequent
12 submittals on October 6, 1986, December 3, 1986, November 13, 1987, and May 11, 1988.

13 There were two basic parts to the Kennecott analysis:

- 14 • The GEP demonstration – which consisted of three subparts: a fluid modeling protocol,
15 the fluid modeling results, and an evaluation of the fluid modeling results with respect to
16 the stack height regulations.
- 17 • A Best Available Retrofit Technology (BART) analysis – performed if the source
18 contended that the NSPS emission limits were infeasible. Relevant factors for this
19 analysis include high cost-effectiveness ratio, excessive local community impact,
20 excessive plant impact, and infeasibility issues. Kennecott provided responses to all the
21 BART factors mentioned above. The cost effectiveness ratio and technical infeasibility
22 issues, however, were determined critical to this review because of their relationship to
23 the emission limitations used in the GEP analyses.

24 Because the Kennecott emissions, as established through MPR, were used in the 1981 SO₂ SIP,
25 EPA's primary concern with the use of any emission rate in the demonstration of GEP was
26 ensuring protection of the NAAQS. The basic concept behind GEP is to prevent sources from
27 using illegal dispersion techniques to avoid emissions controls.

28
29 Kennecott provided extensive data on its GEP analyses.²⁴ To summarize, the GEP demonstration
30 showed that the existing stack height of 1,215 feet met the 40% criterion due to terrain effects
31 and an exceedance of the NAAQS at MPR emission rates. MPR is a technique designed for
32 sources with variable emission rates (e.g., smelters). MPR allows for a frequency distribution of
33 emission rates which will permit extremely high emissions on rare occasions. The MPR
34 methodology was constructed around the recognition that any control strategy would have a

²³ Approval and Promulgation of State Implementation Plans – Utah SO₂ Plan, February 20, 1985, 50 FR 7059,
www.govinfo.gov/content/pkg/FR-1985-02-20/pdf/FR-1985-02-20.pdf.

²⁴ GEP Demonstration and BART Analysis, 53 FR 48942.

1 predictable probability of allowing a violation of the NAAQS. The MPR was based upon
2 allowing a 26% probability of recording a violation. The GEP demonstration satisfies the
3 excessive concentration criteria in EPA's regulation if MPR reflects the proper emission rates.
4 After review, EPA concluded that Kennecott's analyses were acceptable, since Kennecott
5 performed a fluid modeling study consistent with existing guidance and the study was approved
6 by EPA.

7
8 Application of the level of control required by NSPS would reduce the emissions of SO₂ at
9 Kennecott during the stable process phase, but would not affect emission rates under startup,
10 shutdown, malfunction, and upset conditions. This is because the NSPS emission rate is for
11 normal operations and excludes such process conditions. MPR includes startup, shutdown,
12 malfunction, and upset conditions. From the Kennecott assessment, considering only long-term
13 averages, the cost portion is consistent with the tons of SO₂ reduction expected from similar
14 NSPS applications. In the Kennecott BART analysis, the controlling emissions for the
15 determination of GEP appeared to be those under upset, start-up, shutdown, and malfunction
16 conditions. Therefore, while there would be no difference in the emission rates under these
17 conditions as a result of meeting NSPS, there would be a substantial additional cost to control
18 these emissions.

19
20 In summary, the emissions at the smelter from startups, shutdowns, upsets, and malfunctions
21 were included in the MPR emission limits and would be considered in the NAAQS attainment
22 and GEP analyses. Application of NSPS technology would not affect these emission rates and
23 would, therefore, result in no change in demonstrating GEP. It may be possible to reduce annual
24 emissions by requiring additional controls on the smelter, but such reduction would have no
25 relevance to the limiting case for determination of GEP.

26
27 Given the above discussion, EPA proposed to approve²⁵ the Kennecott analysis in the Utah GEP
28 SIP submitted on May 2, 1986, with subsequent submittals on October 6, 1986, December 3,
29 1986, November 13, 1987, and May 17, 1988. However, EPA's review was conducted under a
30 specific assumption: that the emission rate(s) in the SO₂ SIP was sufficient to demonstrate
31 attainment. That assumption followed another critical assumption: that Kennecott owned or
32 controlled the lands in the upper elevation for which no monitoring data exists to demonstrate
33 attainment of the NAAQS.

34
35 Only one comment was received in response to the December 5, 1988, Federal Register which
36 proposed approval of the Kennecott GEP demonstration. The comment was from Kennecott in
37 support of this action. However, prior to publication of the proposed Federal Register approval,

²⁵ Approval and Promulgation of State Implementation Plans: Utah; Stack Height Analyses and Regulations, 53 FR 48942, December 5, 1988, www.govinfo.gov/content/pkg/FR-1988-12-05/pdf/FR-1988-12-05.pdf.

1 EPA received a letter from a landowner in the Oquirrh Mountains expressing concerns about the
2 lack of ambient monitoring in the nonattainment area. This was EPA's first documented
3 information on public access in the nonattainment area other than the Kennecott operation. EPA
4 proceeded to continue its evaluation of the State submittal and to publish its position on the GEP
5 demonstration based on the State submittal but initiated a reevaluation on land ownership above
6 the 5,600 feet elevation in the Oquirrh Mountains. Documentation on the claim of
7 landownership, other than that of the Kennecott operations, was provided by Howard Haynes,
8 Jr., in March 1989.²⁶

9 viii) 1981 SO₂ and 1986 GEP SIP Reassessment

10 Data from the Salt Lake County and Tooele County Assessor offices showed over 80 landowners
11 in the nonattainment area. Kennecott also conducted independent research and verified the list of
12 landowners. One of the critical assumptions of the conditional approval of the 1981 SO₂ SIP and
13 the emission rate was Kennecott's ownership or control of those lands in the potential
14 nonattainment area in the Oquirrh Mountains. The land ownership research revised the EPA's
15 earlier assumptions on the adequacy of the 1981 SO₂ and the 1986 GEP Stack SIPs.

16
17 In response, EPA began discussions with Kennecott and the State to resolve these issues and
18 outline a path forward for addressing the SO₂ and GEP SIPs. During these negotiations, the State
19 was also in the process of developing the PM₁₀ SIP for the Salt Lake County nonattainment area.
20 This process identified SO₂ as a key precursor to PM₁₀ pollution. Sulfates formed from SO₂
21 emissions are among the most common secondary particles contributing to PM₁₀ nonattainment.
22 Kennecott's smelter alone was responsible for 56% of the county's total PM₁₀ emissions,
23 including both primary and secondary particles.

24
25 The State adopted the PM₁₀ SIP in August 1991 and submitted it to the EPA in November of the
26 same year²⁷. The SIP imposed significant SO₂ emission reductions across Kennecott's operations
27 including the mine, concentrator, refinery, power plant, and smelter. The allowable smelter SO₂
28 emissions were reduced from 76,000 tons per year (tpy) or 18,000 lbs/hr annual average as set by
29 the 1981 SO₂ and 1986 GEP SIPs, to 18,500 tpy. This new limit included fugitive emissions and
30 applied to the entire smelter operation. The previous 76,000 tpy cap applied only to emissions
31 from smelter processing units and SO₂ removal systems vented through the 1,215-foot stack and
32 did not account for fugitive emissions. Under the revised PM₁₀ SIP, the stack-specific limit was

²⁶ Approval and Promulgation of State Implementation Plans: Utah; Stack Height Analyses and Regulations and SO₂ Nonattainment Plan, 59 FR 239, December 14, 1994, www.govinfo.gov/content/pkg/FR-1994-12-14/html/94-30607.htm.

²⁷ Approval and Promulgation of Air Quality Implementation Plan: Utah; Revision to the State Implementation Plan Addressing PM₁₀ for Salt Lake and Utah County, July 8, 1994, https://archives.federalregister.gov/issue_slice/1994/7/8/35035-35044.pdf.

lowered to 14,191 tpy, encompassing only emissions from the processing units and pollution control equipment.

ix) 1991 GEP and 1992 SO₂ SIP Submittals

On November 15, 1990, The CAA was amended to address issues like acid rain, urban air pollution, toxic air emissions, and stratospheric ozone depletion. The amendments also established a national operating permits program and strengthened enforcement provisions.²⁸ On May 15, 1992, the Governor of Utah submitted a revision to Section 9, Part B of the SO₂ SIP to address the amendment to the CAA requirement that a SIP revision be submitted by May 15, 1992, for any area that did not have a fully approved SIP as the 1981 SO₂ SIP was only conditionally approved. The significant changes in this SIP revision from that of the 1981 submittal were as follows:

- Revision to the GEP Stack height Section 16 set an allowable emissions limit of 14,191 tpy for the 1,215-foot main stack, as derived in the PM₁₀ SIP.²⁹ This limit reflects the use of double-contact acid plant technology, improved capture of fugitive emissions, and enhanced operation and maintenance.
- The MPR emission limitations and assumptions were removed and replaced with the emission limitation that can be achieved using the NSPS technology, double contact acid plant, or the equivalent of NSPS. NSPS is the presumptive norm for RACT for this facility. The SO₂ SIP was revised to reference the same emission limitations as those stated in the PM₁₀ SIP.
- The 1971 SO₂ NAAQS³⁰ are 0.14 ppm for the 24-hour primary standard, and 0.5 ppm for the 3-hour secondary standard. The 24-hour impact analysis was a rollback analysis that compared the smelter emissions in 1991 (PM₁₀ SIP emission limitation) with the 1979 emissions. The State had monitoring data showing attainment at Lake Point (an area originally defined as ambient air and owned by the Bureau of Land Management but now owned by Kennecott) where exceedances were recorded. The Lake Point site could be considered representative of the closest point in the elevated terrain that would be impacted by the tall stack emissions. Demonstrating attainment at Lake Point would technically support the attainment elsewhere in the elevated terrain that is considered ambient air. The area considered ambient air in the elevated terrain is a significant distance downwind from Lake Point.
- The PM₁₀ SIP emission limitation was based on a 24-hour SO₂ limit; this emission limitation was to be achieved through a given lbs/hr calculated on a 6-hour average. The 24-hour limit was considered “controlling” for PM₁₀ and SO₂ (i.e., the 24-hour limitation

²⁸ 1990 Clean Air Act Amendment, www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary.

²⁹ 1994 Revision to the State Implementation Plan Addressing PM₁₀ for Salt Lake and Utah County, https://archives.federalregister.gov/issue_slice/1994/7/8/35035-35044.pdf.

³⁰ Table of Historical SO₂ NAAQS, www3.epa.gov/ttn/naaqs/standards/so2/s_so2_history.html.

was believed to be the level of control necessary for PM₁₀ attainment, as well as for the SO₂ attainment demonstration). The SO₂ SIP established a 3-hour limitation and verified that such limitation would protect the 3-hour NAAQS.

- Section 4.2 of the Utah Air Conservation Rules was revised to include a 24-hour averaging period for the sulfur content of coal, fuel oil, and fuel mixtures, and to specify the ASTM methods to be used to demonstrate compliance with the limitation and reporting requirement. The previous rule specified a limit for the sulfur content of fuels but did not specify an averaging time or specific ASTM methods. Section 4.6 was also revised to include a 3-hour averaging time for Sulfur Burning Production Sulfuric Acid Plants.
- Specific regulations which were provided for special consideration (including malfunction provisions) on the smelter fluctuating operation were removed. Malfunction provisions for the Kennecott smelter operation were the same as for any stationary source in Utah. This issue was addressed during the PM₁₀ SIP development and was approved under the PM₁₀ SIP federal approval process. These regulation impacts were clarified in the SO₂ SIP revision.

x) 1994 SO₂ and GEP SIP Approval

On December 14, 1994, EPA approved the SO₂ and GEP stack height SIPs, as they were consistent with the EPA guidance.³¹ General SO₂ regulations that were previously determined as deficient with respect to meeting the statewide SO₂ SIP requirements were also approved.

EPA advised the State to ensure consistency with the State's permits and the federally enforceable SIP. The State's permit program was part of the federally approved SIP. The final approval of SO₂ and GEP stack height SIPs also made the emission limitations for these stationary sources federally enforceable. EPA advised the State that if different emission limitations exist, EPA will enforce the more stringent of the two or more emission limitations. This is to ensure that the attainment demonstration of a nonattainment area is maintained. It is therefore critical that the State maintain consistent emission limitations in permits and in federally approved SIPs and update the emission limitations sections of these plans to ensure clarity and consistency.

³¹ Approval and Promulgation of State Implementation Plans, Utah Stack Height Analyses and Regulations, December 14, 1994, 59 FR 18341, www.federalregister.gov/documents/search?conditions%5Bterm%5D=59+FR+18341.

xi) 1999 SO₂ Draft Maintenance Plan Submission

In November 1999, a draft SO₂ maintenance plan and redesignation request³² for Salt Lake and Tooele counties was submitted to the EPA for review. The draft reported that there had been no violations of the 1971 SO₂ NAAQS in the nonattainment area. It credited this to improvements made at the Kennecott smelter, which were sufficient to both achieve and maintain compliance with the standard.

The draft also noted that other major SO₂ sources in the nonattainment area were addressed through the PM₁₀ SIP, which reduced emissions to levels significantly lower than those in the 1980s. These SO₂ limits were federally enforceable, and no additional control measures were considered necessary to maintain the NAAQS.

In higher elevation areas, the Kennecott smelter was identified as the only potential source of concern. However, based on a rollback of earlier modeling data and a straight rollback analysis, the current emission limits in the SO₂ SIP for Kennecott are determined to be more than adequate to ensure continued compliance in those areas. The plan further stated that these limits will remain federally enforceable and are not expected to increase over the next decade.

xii) EPA Review of the 1999 Draft Maintenance Plan

The EPA reviewed the States's submission and identified several deficiencies in the maintenance plan in a letter dated December 17, 1999.³³ These deficiencies are summarized below:

- The letter emphasized the need for a thorough review of a historical, current, and future allowable emissions inventory for SO₂ sources in the nonattainment area to determine if further dispersion modeling is needed.
- A screening analysis was recommended to determine the need for further dispersion modeling. This involved reviewing emissions, performing screening modeling if future emissions were significant, and potentially more refined modeling if the screening modeling indicated violations.
- The letter included several comments on the enforceability of emission limits within the maintenance plan, stressing that limits must remain in effect, be federally enforceable, and be consistent with NAAQS timeframes. Specific comments were made regarding Kennecott's emission limits, stating the State must commit to current emission levels in place or analyze and project growth increase.
- The letter deemed the contingency measures outlined in the draft maintenance plan to be insufficient, as the draft lacked clear identification of potential measures, a schedule and

³² Draft SO₂ Maintenance Plan and Redesignation Request, November 1999.

³³ December 17, 1999, Letter from the EPA Region 8 in response to Utah's draft maintenance plan submission.

1 procedure for adoption and implementation, and a specific time limit for State action,
2 with a commitment to fully implement corrective measures within one year of a NAAQS
3 violation.

- 4 ● The EPA noted that the draft maintenance plan does not provide a projected maintenance
5 year which is a required minimum of 10 years from the approved maintenance plan. The
6 maintenance plan shall include attainment and maintenance year emissions inventories
7 and explain how maintenance will be ensured.
- 8 ● Additionally, the letter requested clarification regarding the operation and replacement of
9 SO₂ monitors at the Lakepoint site in 1992.

10 xiii) Developing Modeling Protocol

11 Since the EPA's review of the 1999 draft Maintenance Plan, the State has developed a modeling
12 protocol³⁴ to demonstrate attainment of the 1971 NAAQS in the nonattainment area. The
13 protocol outlined the procedures, assumptions, data, and models to be used by the State to predict
14 ambient SO₂ concentrations from five petroleum refineries in Salt Lake and Davis counties. The
15 modeling analysis was requested by the EPA as a supplement to Utah's earlier effort to
16 redesignate Salt Lake County and part of Tooele County to attainment.

17
18 The EPA found the technical aspects of the modeling protocol acceptable, including the use of
19 alternative models, overlapping modeling domains, nearby sources, urban/rural dispersion
20 coefficients, background concentrations (with a request for Kennecott's annual emissions for
21 documentation), meteorological data, and receptor locations³⁵. However, the modeling protocol
22 did not include specific information regarding emission points, such as emission rates, caps,
23 routine flare emissions, stack heights, and enforceable measures. The State agreed to address
24 these concerns in the Maintenance Plan and received conditional approval from the EPA for the
25 modeling protocol³⁶.

26 xiv) 2004 SO₂ Draft Maintenance Plan Submission

27 The State drafted a new SO₂ Maintenance Plan³⁷ for the Salt Lake County and Tooele County
28 nonattainment areas and submitted it to the EPA for review on August 20, 2004. The newly
29 drafted Plan stated that there had been no violation in the nonattainment areas of any primary or
30 secondary NAAQS for SO₂ since 1981. This lack of monitored violations was attributed to the
31 permanent and enforceable emission reductions at the Kennecott main stack which led to the

³⁴ October 4, 2001, SO₂ Modeling Protocol, State submittal to the EPA.

³⁵ November 14, 2001, EPA Review of October 4, 2001 Modeling Protocol for Salt Lake County Sulfur Dioxide (SO₂) Redesignation Study, EPA letter to the State.

³⁶ November 14, 2001, EPA Review of October 4, 2001 Modeling Protocol for Salt Lake County Sulfur Dioxide (SO₂) Redesignation Study, EPA letter to the State.

³⁷ January 5, 2005, Sulfur Dioxide Maintenance Provisions for the Salt Lake-Tooele Sulfur Dioxide Nonattainment Area. Section IX.B.6.

1 area's original nonattainment status. Based on this, the State requested redesignation of the
2 nonattainment area. No modeling analysis was included in the draft Maintenance Plan in an
3 effort to demonstrate attainment.

4 **xv) EPA Review of the 2004 Draft Maintenance Plan**

5 In a letter dated November 4, 2004, the EPA outlined their findings and comments for the draft
6 Maintenance Plan.³⁸ The letter stated that based on the preliminary review of the draft, several
7 fundamental requirements for maintenance plans and redesignations to attainment had not been
8 satisfied. The draft also did not demonstrate maintenance, project a maintenance date, or contain
9 sufficient contingency measures. On January 4, 2005, the EPA followed up in a letter
10 recommending deferred action on the Maintenance Plan and redesignation request due to the
11 significant unaddressed issues.³⁹ On April 19, 2005, the State formally submitted the SO₂
12 Maintenance Plan for Salt Lake County and parts of Tooele County.⁴⁰ The EPA never formally
13 acted on the SO₂ Maintenance Plan. In a letter dated November 12, 2019, the State withdrew
14 "UT SO₂ Redesignation and Maintenance Plan for Salt Lake City and UT SO₂ Redesignation and
15 Maintenance Plan for parts of Tooele County," both submitted on April 19, 2005⁴¹. The letter
16 stated that "the Utah Division of Air Quality is working closely and cooperatively with the EPA
17 to craft an approvable maintenance plan so EPA can act on it promptly following submission."

18 **IX.B.11.c Redesignation Requirements**

19 Section 107(d)(3)(E) of the Act outlines five requirements that a nonattainment area must satisfy
20 before an area may be eligible for redesignation from nonattainment to attainment. Table 3
21 identifies the redesignation requirements as they are stated in Section 107(d)(3)(E) of the Act.
22 Each element will be addressed in turn, with the central element being the maintenance plan
23 found in Subsection IX.B.11.d below.
24
25

³⁸ November 4, 2004, Sulfur Dioxide Maintenance Provisions, EPA letter to the State.

³⁹ January 4, 2005, Sulfur Dioxide Maintenance Provisions, EPA letter to the State.

⁴⁰ April 19, 2005, Sulfur Dioxide Maintenance Provisions for the Salt Lake-Tooele Sulfur Dioxide Nonattainment Area. Section IX.B.6, Governor's letter to the EPA.

⁴¹ November 12, 2019, State of Utah withdrawing the maintenance plan, Governor's letter to the EPA.

1 Table 3: Requirements to Redesignation in the Federal Clean Air Act

Category	Requirement	Reference	Addressed in Section
Attainment of Standard	Most recent two complete consecutive years of quality-assured monitoring data must show that violations of the standard are no longer occurring ⁴²	CAA §107(d)(3)(E)(i)	IX.B.11.c(i)
Approved SIP	The applicable implementation plan for the area must be fully approved	CAA §107(d)(3)(E)(ii)	IX.B.11.c(ii)
Permanent and Enforceable Reductions	The State must be able to reasonably attribute the improvement in air quality to emission reductions that are permanent and enforceable	CAA §107(d)(3)(E)(iii) Calcagni memo (Sec. 3, para 2) ⁴³	IX.B.11.c(iii)
Section 110 and Part D Requirements	The State must verify that the area has met all requirements applicable to the area under Section 110 and Part D	CAA: §107(d)(3)(E)(v), §110(a)(2), Sec 171	IX.B.11.c(iv)
Maintenance Plan	The Administrator has fully approved the Maintenance Plan for the area as meeting the requirements of CAA §175A	CAA §107(d)(3)(E)(iv)	IX.B.11.c(v) and IX.B.11.d

2 i. The Area Has Attained the 1971 SO₂ NAAQS

3 *CAA 107(d)(3)(E)(i) - The Administrator determines that the area has attained the national*
4 *ambient air quality standard.* To satisfy this requirement, the State must show that the area is
5 attaining the applicable NAAQS. According to EPA's guidance⁴⁴ concerning area
6 redesignations, there are generally two components involved in making this demonstration: (1)
7 relies upon ambient air quality data which should be representative of the area of highest
8 concentration and should be collected and quality assured in accordance with 40 CFR 58; and
9 (2) relies upon supplement air quality modeling. Each component will be addressed in turn.

⁴² Memorandum From Sheldon Myers, Director, EPA Office of Air Quality Planning and Standards to Regional Office Air Division Directors, "Section 107 Designation Policy Summary" April 21, 1983, <https://www.federalregister.gov/d/2014-09458/p-92>.

⁴³ John Calcagni, September 4, 1992, EPA Memorandum "Procedure for Processing Requests to redesignate Areas to Attainment" https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf.

⁴⁴ John Calcagni, September 4, 1992, EPA Memorandum "Procedure for Processing Requests to Designate Areas to Attainment" https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf.

1 **(1) Ambient Air Quality Data (Monitoring) and Utah's Monitoring Network**

2 The NAAQS for the 1971 SO₂ standard are as follows⁴⁵: primary standards include an annual
3 (calendar year) arithmetic mean of 0.03 ppm and a 24-hour midnight to midnight block average
4 of 0.14 ppm. An exceedance of the annual standard is a violation of the NAAQS, as are two
5 exceedances of the 24-hour standard in any one calendar year at any one monitor site. In
6 addition, there is a secondary standard of 0.5 ppm measured as a 3-hour block average,
7 calculated from successive non-overlapping 3-hour blocks starting at midnight. Two
8 exceedances of the 3-hour standard in a calendar year at any one monitoring site is a violation of
9 the NAAQS. In order to demonstrate attainment of these standards, the State must collect eight
10 consecutive calendar quarters (two years) of ambient data that is below the levels outlined
11 above.⁴⁶ It is important to note that although the current SO₂ standards^{47, 48} are significantly more
12 stringent than those established in 1971, they are being met with a substantial margin of
13 compliance.

14
15 The Division's Air Monitoring section maintains an ambient air monitoring network in Utah in
16 accordance with 40 CFR 58 that collects both air quality and meteorological data. Figure 1
17 shows the location of both historical and present SO₂ monitoring sites in the state. The data
18 collected at these sites are routinely audited by the EPA and meets the agency's requirements for
19 air monitoring networks.
20

⁴⁵ 40 CFR 50.4, National primary ambient air quality standards for sulfur oxides (sulfur dioxide),
<https://www.ecfr.gov/current/title-40/section-50.4>.

⁴⁶ Memorandum From Sheldon Myers, Director, EPA Office of Air Quality Planning and Standards, to Regional
Office Air Division Directors, "Section 107 Designation Policy Summary" April 21, 1983.

⁴⁷ 40 CFR 50, Review of the Primary National Ambient Air Quality Standards for Sulfur Oxides,
www.federalregister.gov/documents/2019/03/18/2019-03855/review-of-the-primary-national-ambient-air-quality-standards-for-sulfur-oxides.

⁴⁸ 40 CFR 50, Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen, Oxides of
Sulfur, and Particulate Matter,
www.govinfo.gov/content/pkg/FR-2024-12-27/pdf/2024-29463.pdf.

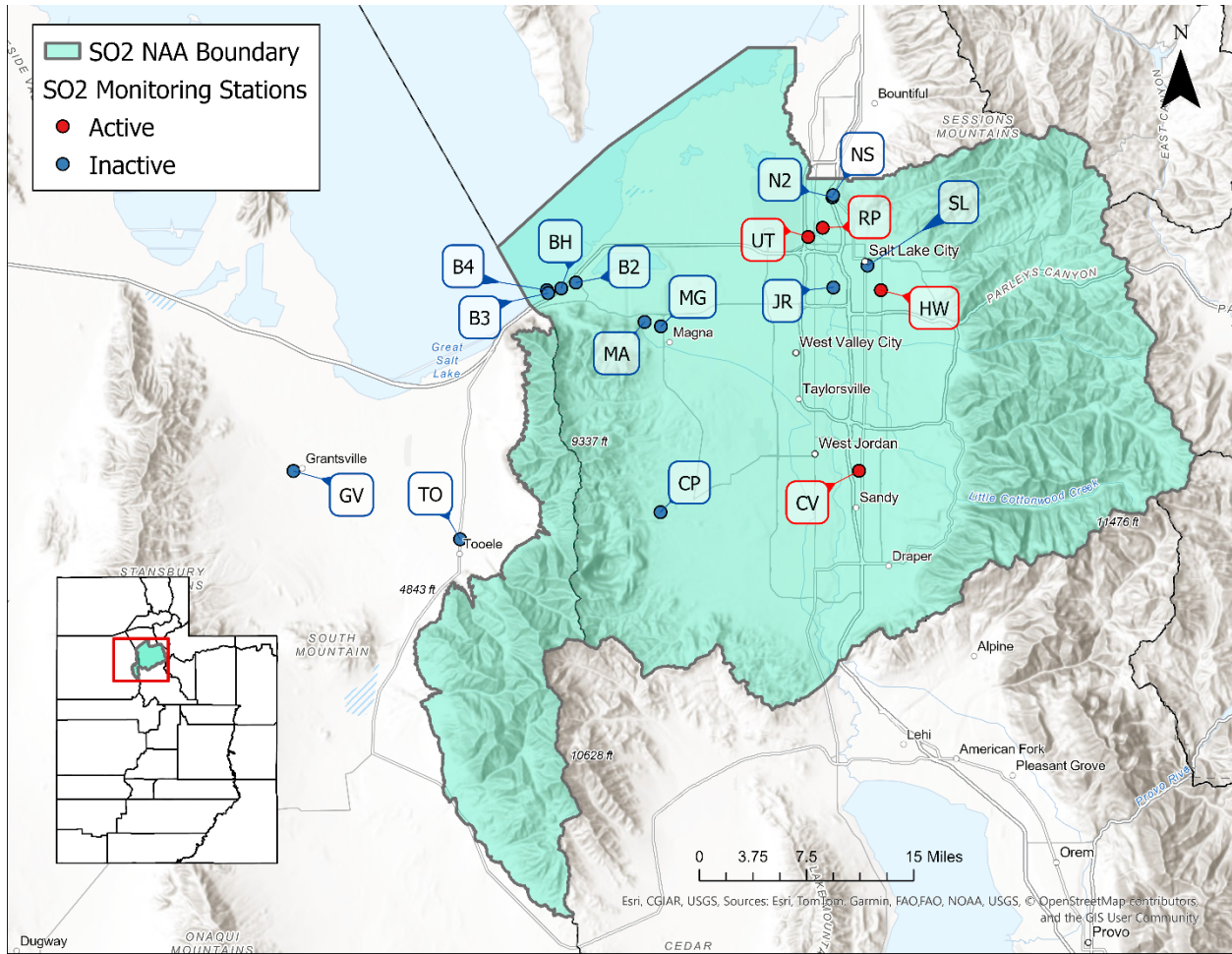


Figure 1: SO₂ nonattainment area boundary and monitoring network

Table 4 shows the SO₂ monitor values from 1981 to 2024. The data was downloaded from EPA's Air Quality System (AQS) database. Monitors that did not have three consecutive years of data available were excluded from this table. As shown in Table 4, a violation of the 24-hour standard was recorded at two monitors in 1981. Since then, there has been no recorded violation of the 1971 SO₂ standards in the nonattainment area.

1 Table 4: Nonattainment area monitoring data from 1981 – 2024

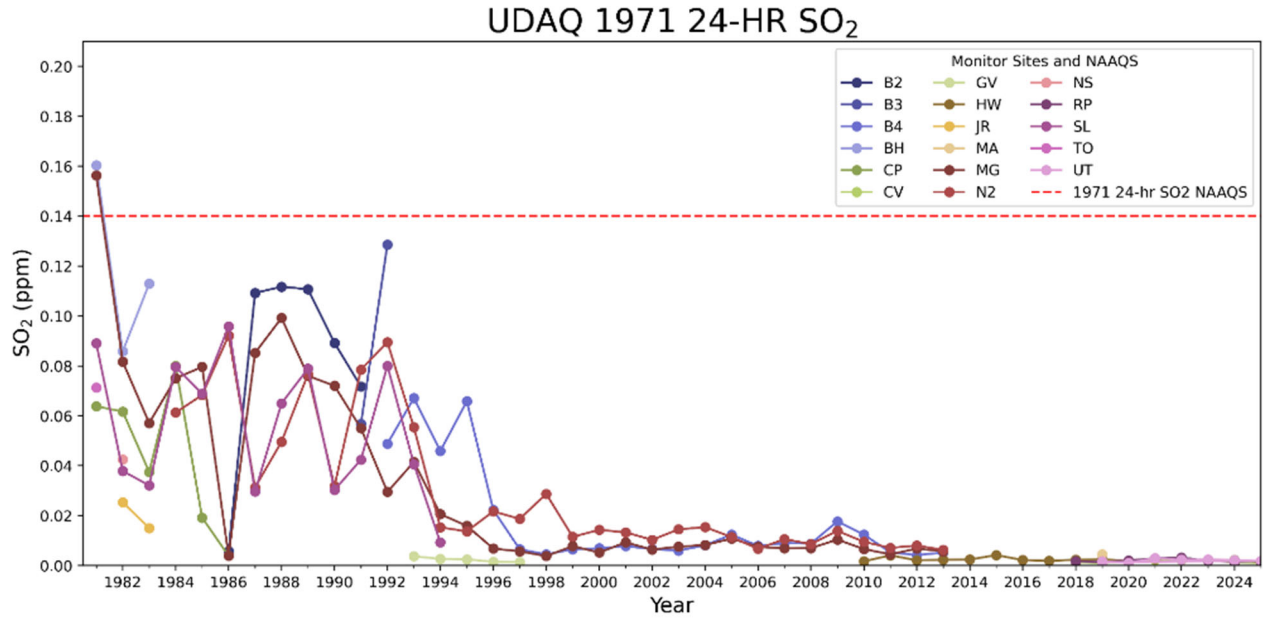
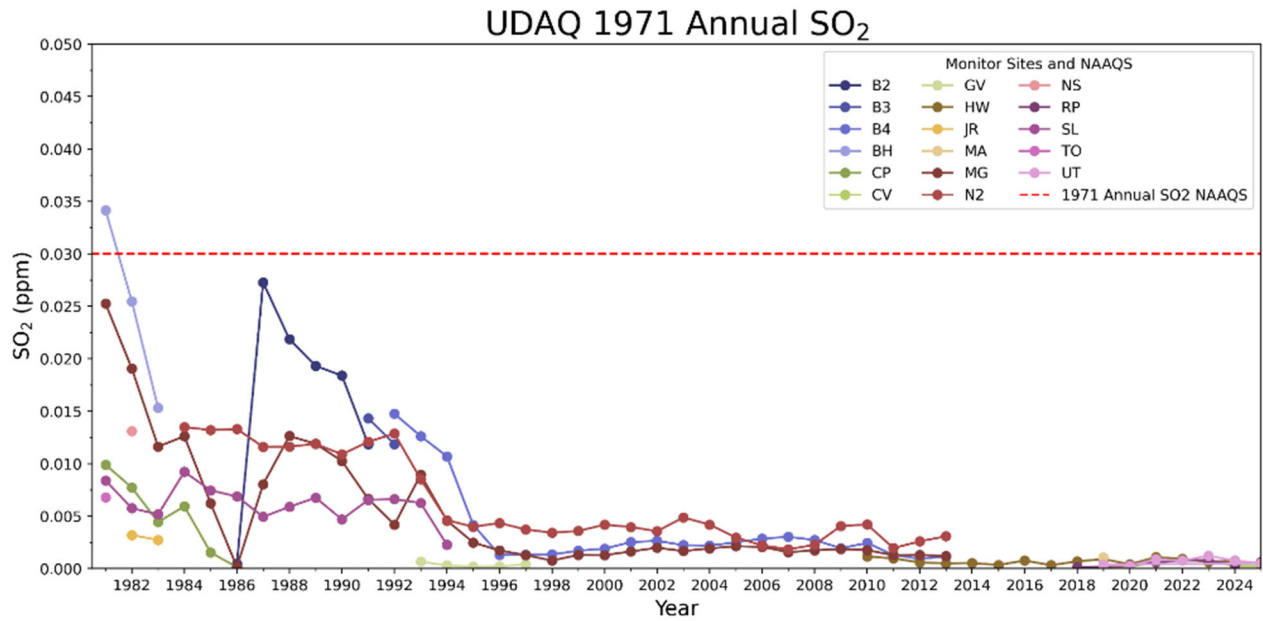
Year	AQS Site Number	1 st 24-hr Max (ppm)	Mean Annual Standard* (ppm)	3-hr Arithmetic Mean* (ppm)
1971 SO₂ Standards		0.14	0.03	0.5
1981	TO, MG, BH, SL, CP	0.160	0.034	0.034
1982	NS, JR, MG, BH, SL, CP	0.086	0.025	0.026
1983	JR, MG, BH, SL, CP	0.113	0.015	0.015
1984	N2, MG, SL, CP	0.080	0.013	0.013
1985	N2, MG, SL, CP	0.080	0.013	0.013
1986	B2, N2, MG, SL, CP	0.096	0.013	0.013
1987	B2, N2, MG, SL	0.109	0.027	0.028
1988	B2, N2, MG, SL	0.112	0.022	0.022
1989	B2, N2, MG, SL	0.111	0.019	0.019
1990	B2, N2, MG, SL	0.089	0.018	0.019
1991	B2, N2, MG, B3, SL	0.079	0.014	0.140
1992	N2, MG, B3, B4, SL	0.129	0.015	0.015
1993	N2, MG, B4, SL, GV	0.067	0.013	0.013
1994	N2, MG, B4, SL, GV	0.046	0.011	0.011
1995	N2, MG, B4, GV	0.066	0.004	0.004
1996	N2, MG, B4, GV	0.022	0.004	0.004
1997	N2, MG, B4, GV	0.019	0.004	0.004
1998	N2, MG, B4	0.029	0.003	0.003
1999	N2, MG, B4	0.012	0.004	0.004
2000	N2, MG, B4	0.014	0.004	0.004
2001	N2, MG, B4	0.013	0.004	0.004
2002	N2, MG, B4	0.010	0.004	0.004
2003	N2, MG, B4	0.015	0.005	0.005
2004	N2, MG, B4	0.015	0.004	0.004
2005	N2, MG, B4	0.011	0.003	0.003
2006	N2, MG, B4	0.008	0.003	0.003
2007	N2, MG, B4	0.011	0.003	0.003
2008	N2, MG, B4	0.009	0.003	0.003
2009	N2, MG, B4	0.018	0.004	0.004
2010	N2, MG, B4, HW	0.012	0.004	0.004
2011	N2, MG, B4, HW	0.007	0.002	0.002
2012	N2, MG, B4, HW	0.008	0.003	0.003
2013	N2, MG, B4, HW	0.006	0.003	0.003
2014	HW	0.002	0.001	0.000

Year	AQS Site Number	1 st 24-hr Max (ppm)	Mean Annual Standard* (ppm)	3-hr Arithmetic Mean* (ppm)
2015	HW	0.004	0.000	0.000
2016	HW	0.002	0.001	0.001
2017	HW	0.002	0.000	0.000
2018	CV, HW, RP	0.002	0.001	0.001
2019	MA, CV, HW, RP, UT	0.005	0.001	0.001
2020	CV, HW, RP, UT	0.002	0.000	0.000
2021	CV, HW, RP, UT	0.003	0.001	0.001
2022	CV, HW, RP, UT	0.003	0.001	0.001
2023	CV, HW, RP, UT	0.003	0.001	0.001
2024	CV, HW, RP, UT	0.002	0.001	0.001

TO: 49-045-0001; MG: 49-035-1001; BH: 49-035-2002; SL: 49-035-3001; CP: 49-035-4001; N2: 49-035-0012; B2: 49-035-0005; B4: 49-035-2004; HW: 49-035-3006; CV: 49-035-2005; RP: 49-035-3010; UT: 49-035-3015; NS: 49-035-0007; JR: 49-035-0009; B3: 49-035-2003; GV: 49-045-0002; MA: 49-035-1007

*Monitoring data was obtained from the AQS database on August 13, 2025. Discrepancies may be present due to historical recordkeeping practices and rounding errors.

The time series plots presented below illustrate the monitored SO₂ concentration from 1981 to 2024 in the nonattainment area. The plots show a clear and consistent downward trend in monitored SO₂ concentrations over the 43-year period. This decline is evident for both the primary and secondary SO₂ standards, indicating improvements in air quality that benefit both public health (primary standard) and environmental welfare (secondary standard). In the plots, the applicable SO₂ standard is represented by a dotted line, providing a visual reference point for assessing compliance over time, suggesting a positive trajectory toward air quality improvement.

Figure 2: Monitored SO₂ values compared with 1971 24-Hour SO₂ standardFigure 3: Monitored SO₂ values compared with 1971 Annual SO₂ standard

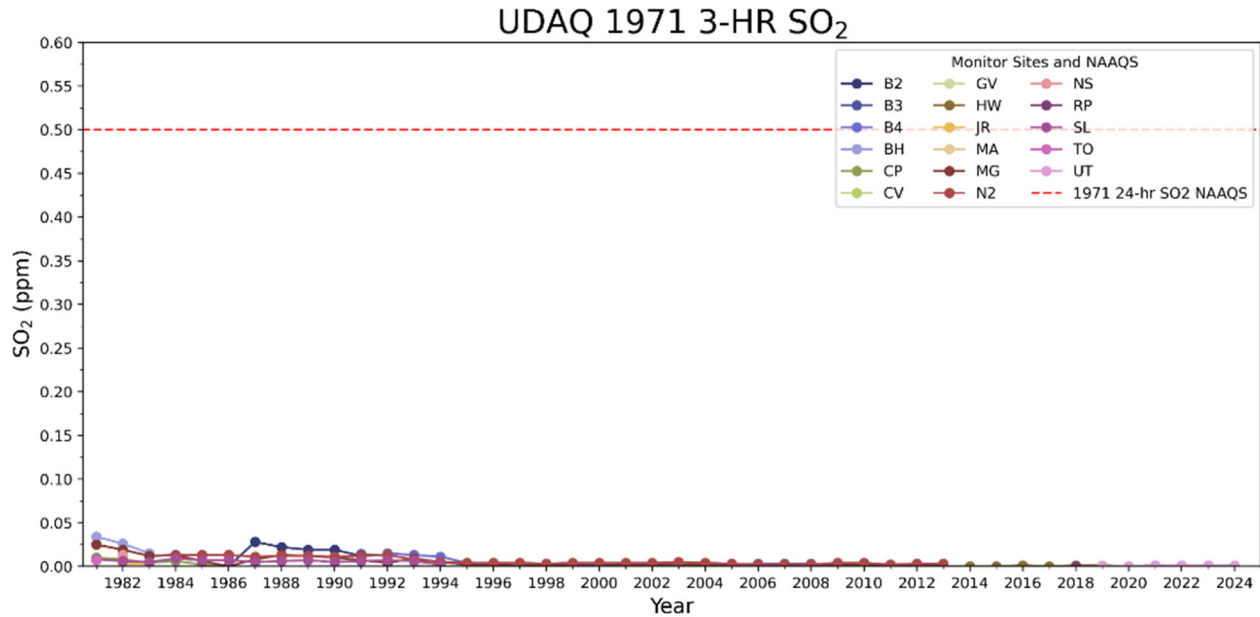


Figure 4: Monitored SO₂ values compared with 1971 3-hour SO₂ standard

(2) Modeling Element

EPA guidance⁴⁹ concerning redesignation requests and maintenance plans discusses the requirement that the area has attained the standard and notes that air quality modeling may be necessary to determine the representativeness of the monitored data. Areas that were designated nonattainment based on modeling will generally not be redesignated to attainment unless an acceptable modeling analysis indicates attainment. Dispersion modeling was conducted for the purpose of this maintenance demonstration to show compliance with the 1971 SO₂ NAAQS. Findings of the modeling analysis are summarized and discussed below. A detailed report of the modeling effort can be found in Appendix 1.

A. Introduction

The modeling effort was supported by Ramboll for use in the attainment demonstration. The model was run for all three 1971 standards. The modeling platform developed for this purpose incorporated a detailed modeling protocol, input from the Division and EPA Region 8 through a series of meetings, emissions data and stack characteristics for permitted sources provided by the Division, as well as relevant federal guidance on state implementation plan modeling, including the use of the AERMOD modeling system in accordance with 40 CFR Part 51, Appendix W.

⁴⁹ John Calcagni, September 4, 1992, EPA Memorandum "Procedure for Processing Requests to Redesignate Areas to Attainment" https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf.

A base year emissions inventory was provided by the Division, consisting of potential emissions and actual emissions for the most recent available year (2023) for sources in the airshed. The modeling demonstration includes consideration of a representative background concentration and the explicitly modeled impacts of six facilities in or near the nonattainment area. To maintain a conservative approach, the facilities were modeled based on their facility-wide allowable emission limits, which exceed the actual emissions by a considerable margin. These identified six facilities are:

- Kennecott Smelter and Refinery;
- Gadsby Power Plant;
- Tesoro Refinery;
- Chevron Refinery;
- Big West Refinery; and
- HF Sinclair Refinery.

The complete list of sources, site potentials to emit, and 2023 actual emissions for facilities in the nonattainment area and surrounding area are provided in Appendix 1.

Table 5: 1971 SO₂ Standards

Period	Standard	Value (ppm)	Value (µg/m ³)	Form	SIL* (µg/m ³)
3-Hour	Secondary	0.5	1,300	Not to be exceeded more than once per year (Highest Second High)	25
24-Hour	Primary	0.14	365	Not to be exceeded more than once per year (Highest Second High)	5
Annual	Primary	0.030	80	Annual mean; Not to be exceeded	1

*Significant Impact Level

Table 6: Background Design Value (DV)

Period	DV (ppb)	DV (µg/m ³)*
3-Hour	4.5	11.79
24-Hour	2.8	7.34
Annual	1.22	3.20

*Using the EPA conversion rate of 1 ppb SO₂ = 2.62 (µg/m³) SO₂

To aid in the modeling interpretation, three runs were performed for each standard:

- A “combined” run where effects of all emissions units are modeled at all receptors (including the effects of Kennecott emissions on its own property). This inclusion of on-

property impacts of emissions is a simple and conservative first run, designed to identify areas of refinement if needed, since not all modeled impacts using this approach can be compared to the NAAQS.

- A “Kennecott zero out” run where the emission rates of Kennecott emission units are set to zero. These runs may be used to evaluate NAAQS compliance at receptors inside the Kennecott fenceline.
- An “outside Kennecott” run where the receptors inside the Kennecott fenceline are excluded. These runs may be used to evaluate NAAQS compliance at all locations to which the public has access (i.e., not owned and controlled by Kennecott).

Note that the procedures regarding evaluation of ambient air for Kennecott are equally valid for the other five explicitly modeled facilities as well (e.g., effects of emissions from Tesoro emission units are not considered when evaluating NAAQS compliance at receptors on land owned and controlled by Tesoro where public access is effectively precluded). However, since modeled concentrations in northern Salt Lake County were well under the NAAQS, even within facility boundaries, the refined treatment of ambient air was not performed for those facilities.

B. 3-Hour Results

The results of the 3-hour modeling are shown in Table 7. Figure 2 and Figure 3 illustrate the impacts of nonattainment area-wide, and in the immediate vicinity of Kennecott. The concentrations reported are the highest second-high concentrations in any year, in accordance with the form of the NAAQS. The total impacts are the sum of the modeled value and the background value and are compared to the NAAQS.

Table 7: Results of 3-Hour Modeling

Scenario	Year	Modeled Value (µg/m ³)	Background Value (µg/m ³)	Total Impact (µg/m ³)	NAAQS (µg/m ³)
Combined	2020	935.96	11.79	947.75	1,300
Kennecott zero out	2022	7.11	11.79	18.90	
Outside Kennecott	2020	244.28	11.79	256.07	

Total impacts at all receptors are below the NAAQS, even when conservatively including Kennecott’s own impact on its own property. Indeed, as seen in Figure 3, the receptor with the highest impact is at the main smelter and refinery building itself, which is not in ambient air. When the impacts of the other facilities and background are evaluated at the Kennecott receptors (the zero out run), these impacts (18.90) are below the 3-hour SO₂ Significant Impact level (SIL) of 25 micrograms per cubic meter (µg/m³), demonstrating sources other than Kennecott have a de minimis impact at these receptors.

1
2 When considering the highest impacts (in the form of the standard) at all ambient air receptors
3 (outside Kennecott run), the impacts are less than 20% of the NAAQS. It is noted that these
4 results conservatively include the facility impacts within their fenceline for the other explicitly
5 modeled facilities. The analysis demonstrates that the cumulative impacts at locations of public
6 access are well below the level of the 3-hour SO₂ NAAQS throughout the nonattainment area.



Figure 5: Impacts of 3-Hour SO₂ (H₂H) throughout the nonattainment area.

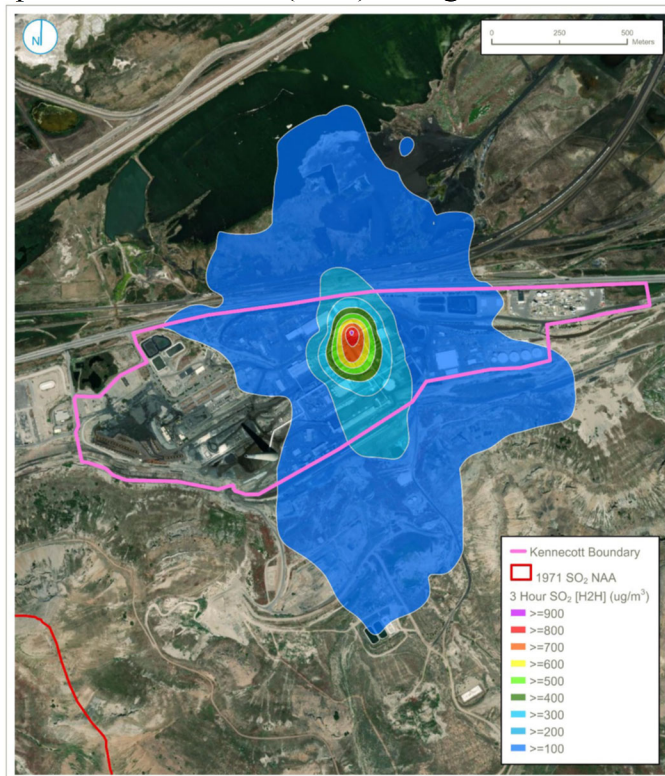


Figure 6: Impacts of 3-Hour SO₂ (H₂H) in the vicinity of the Kennecott facility.

C. 24-Hour Results

The results of the 24-hour modeling are shown in Table 8. Figure 4 and Figure 5 illustrate the impacts nonattainment area-wide, and in the immediate vicinity of Kennecott. The concentrations reported are the highest second-high concentrations in any year, in accordance with the form of the NAAQS. The total impacts are the sum of the modeled value and the background value and are compared to the NAAQS.

Table 8: Results of 24-Hour Modeling

Scenario	Year	Modeled Value ($\mu\text{g}/\text{m}^3$)	Background Value ($\mu\text{g}/\text{m}^3$)	Total Impact ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)
Combined	2024	513.85	7.34	521.19	365
Kennecott zero out	2024	1.20	7.34	8.54	
Outside Kennecott	2024	112.60	7.34	119.94	



Figure 7: Impacts of 24-Hour SO₂ (H2H) throughout the nonattainment area.

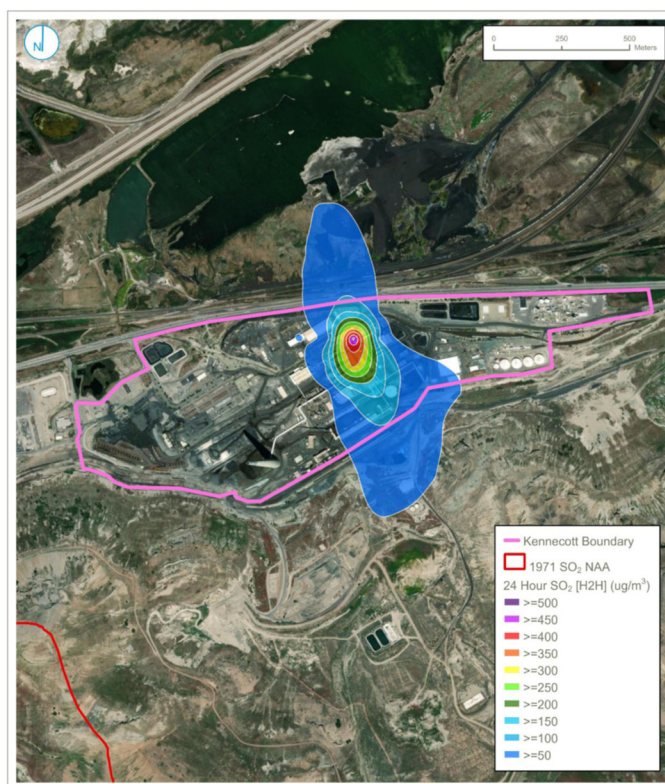


Figure 8: Impacts of 24-Hour SO₂ (H₂H) in the vicinity of the Kennecott facility.

There are two receptors on the Kennecott property that require additional refinement since they are not ambient air to Kennecott. Receptors at (399100, 4509000) and (399100, 4508900) have total impacts that, when including Kennecott emissions, exceed 365 µg/m³. However, these two receptors are on the Kennecott property, with one on the footprint of the smelter building itself and one immediately adjacent to it. When the Kennecott emissions are excluded in the zero out run, the modeled impacts of the other facilities on the Kennecott property (1.20 µg/m³) are below the level of the 24-hour SIL (5 µg/m³), demonstrating that impacts from other facilities are de minimis for the 24-hour standard at these receptors. Accordingly, the 24-hour SO₂ NAAQS is satisfied at all points in the domain, both inside and outside the Kennecott property.

When considering the highest impacts (in the form of the standard) at all ambient air receptors (outside Kennecott run), the impacts are less than 33% of the NAAQS. It is noted that these results conservatively include the facility impacts within their fenceline for the other explicitly modeled facilities. The analysis demonstrates that the cumulative impacts at locations of public access are well below the level of the 24-hour SO₂ NAAQS throughout the nonattainment area.

D. Annual Results

The results of the annual modeling are shown in Table 9. Figure 6 and Figure 7 illustrate the impacts nonattainment area-wide, and in the immediate vicinity of Kennecott. Concentrations reported are the highest annual average in any year, in accordance with the form of the 1971 NAAQS. The total impacts are the sum of the modeled value and the background value and are compared to the NAAQS.

Table 9: Results of Annual Modeling

Scenario	Year	Modeled Value (µg/m ³)	Background Value (µg/m ³)	Total Impact (µg/m ³)	NAAQS (µg/m ³)
Combined	2024	55.00	3.20	58.20	80
Kennecott zero out	2022	0.02	3.20	3.22	
Outside Kennecott	2022	7.13	3.20	10.33	

Total impacts at all receptors are below the NAAQS, even when considering Kennecott's own impacts on its own property. Indeed, as seen in Figure 7, the receptor with the highest impact is at the main smelter and refinery building itself. When the impacts of the other facilities are evaluated at the Kennecott receptors, these impacts (0.02 µg/m³) are below the annual SO₂ SIL of 1 µg/m³, demonstrating sources other than Kennecott have a de minimis impact in this area.

When considering the highest impacts (in the form of the standard) at all ambient air receptors (outside Kennecott run), the impacts are less than 13% of the NAAQS. It is noted that these results conservatively include the facility impacts within their fenceline for the other explicitly modeled facilities. The analysis demonstrates that the cumulative impacts at locations of public access are well below the level of the annual SO₂ NAAQS throughout the nonattainment area.

In 2024, EPA promulgated a new secondary annual SO₂ standard of 10 ppb (26.2 µg/m³)⁵⁰, averaged over the most recent three years. As is demonstrated by the model runs presented here, this standard is easily satisfied throughout the model domain.⁵¹ Assuming the maximum annual impact of 10.33 µg/m³ persists for three consecutive years, the impacts are less than 40% of the new secondary annual NAAQS.

⁵⁰ 89 FR 105692, <https://www.federalregister.gov/documents/2024/12/27/2024-29463/review-of-the-secondary-national-ambient-air-quality-standards-for-oxides-of-nitrogen-oxides-of>.

⁵¹ Results presented in Table 5 are for a single year whereas the new 2024 secondary standard is a multi-year average, so the results presented in Table 5 are in a form that is more conservative than the form of the new NAAQS.



Figure 9: Impacts of Annual SO₂ (highest single year) throughout the nonattainment area.

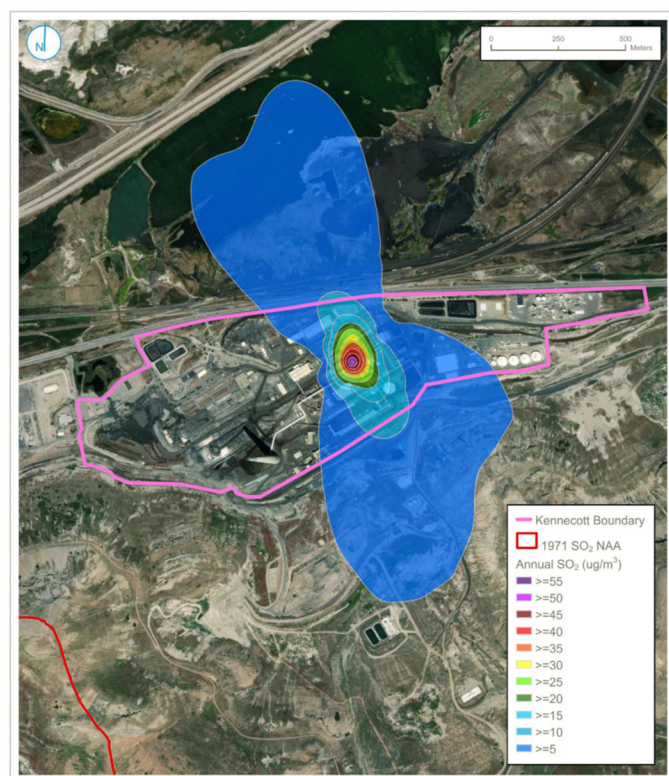


Figure 10: Impacts of Annual SO₂ (highest single year) in the vicinity of the

1 E. Discussion

2 As shown in subsections A through D, the modeled total impacts for the SLC NAA and TC NAA
3 comply with the 1971 NAAQS. The only receptors where concentrations exceeded the level of
4 the NAAQS were on the Kennecott property when modeling all emission units. Once the
5 Kennecott emissions were removed from consideration at those receptors, impacts of the other
6 facilities and background were found to be far below the standards.

7
8 At receptors outside the Kennecott boundary, the highest total impacts ranged from about
9 13% of the standard (annual) to about 33% of the standard (24-hour). Concentrations versus each
10 of the standards considered are far below the NAAQS at locations within ambient air.

11
12 The low magnitude of modeled impacts versus the NAAQS provides assurance that NAAQS
13 compliance within the airshed is robust and would be unaffected by different parameterizations
14 in the model setup. For example, as noted in the development of modeled emission rates
15 (Appendix 1), most facilities that were explicitly modeled operate under facility-wide restrictions
16 rather than a series of restrictions applicable to each individual emission unit. Where possible,
17 design capacities of each unit were used to calculate an individualized allowable emission rate
18 for that unit, while remaining unassigned emissions under the facility-wide cap were assigned to
19 units for which an individualized potential emission rate could not be determined. If those units
20 for which individualized totals were able to be calculated were emitting less than their calculated
21 rates, then the amount of unassigned emissions would be greater, and those units receiving the
22 unassigned emissions would then be able to emit at a higher rate.

23
24 With modeled impacts at ambient receptors being no more than one-third of any applicable
25 NAAQS, dramatic increases in emission rates – beyond the facility’s permitted levels – would
26 be necessary to obtain concentrations near the level of the NAAQS.

27
28 Similarly, there is such ample headroom between the modeled values and the NAAQS that
29 remaining uncertainty in stack parameters should not be a concern. Where the reviewed
30 information contained two different stack parameters for each unit, the lower value of the
31 parameter was chosen for modeling (i.e., lower stack height, smaller release temperature,
32 smaller release velocity, smaller stack diameter). In most instances, the choice of these
33 conservative parameters are expected to result in lower plume rise, less dispersion, and higher
34 modeled concentration. While the central portion of the nonattainment area is relatively flat,
35 there is rugged terrain in the western and eastern portions of the nonattainment areas. Complex
36 terrain may result in local hotspots of higher concentrations at distance from the facility. In the
37 present exercise, it should be emphasized that modeled total impacts at ambient receptors were only
38 13 to 33 percent of NAAQS, depending on the particular standard chosen. Given the small
39 magnitude of modeled impacts relative to the NAAQS, there is room if modeled results were to

change for a different choice of stack parameters. Additionally, the facility producing the highest absolute impacts (Kennecott) was modeled with stack parameters that were previously reviewed by the EPA, and as seen in Figure 3, Figure 5, and Figure 7, the highest impacts at Kennecott occur at the facility itself rather than at distant hotspots.

In conclusion, the results of this modeling demonstration indicate the Salt Lake-Tooele 1971 SO₂ nonattainment areas are in attainment for the three standards under the 1971 SO₂ NAAQS at facilities' currently permitted SO₂ emission rates.

ii. Fully Approved Applicable Implementation Plan for SO₂

CAA 107(d)(3)(E)(ii) - The Administrator has fully approved the applicable implementation plan for the area under section 110(k). The 1990 amendments to the CAA required states to submit SIP revisions by May 15, 1992, to address nonattainment of the 1971 SO₂ NAAQS. In response, the State submitted revisions to the GEP stack height SIP on December 23, 1991, followed by the revised SO₂ SIP on May 15, 1992. The EPA fully approved both the GEP and SO₂ SIPs, as published in the Federal Register (59 FR 18341) on December 14, 1994.⁵² The SIPs became effective on January 13, 1995. A detailed history of the SIP approval can be found in the Background section of this document.

iii. Improvement in Air Quality Due to Permanent and Enforceable Reductions in Emissions

CAA 107(d)(3)(E)(iii) - The Administrator determines that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions. As discussed in the background section of this document, the SO₂ impact that led to the area's nonattainment designation in 1978 was attributed entirely to Kennecott, and primarily to its smelting process. The history of enforceable emission reductions at Kennecott and improved air quality is discussed below.

(1) Emissions Reductions at Kennecott

Between 1978 and 1995, Kennecott undertook significant modernization of its smelting operations in response to the 1971 SO₂ NAAQS violations and the later PM₁₀ SIP. Kennecott replaced older reverberatory furnaces with Noranda reactors and installed a new single-contact acid plant to control SO₂ emissions from both reactors and converters. A 1,200-foot stack was constructed to improve dispersion and reduce ground-level impacts. Concurrently, improved

⁵² Approval and Promulgation of State Implementation Plans, Utah Stack Height Analyses and Regulations, December 14, 1994, 59 FR 18341, www.federalregister.gov/documents/search?conditions%5Bterm%5D=59+FR+18341.

capture systems and changes in operational practices were made to reduce fugitive emissions. In the 1981 SIP⁵³ submission, the Division revised the Utah administrative rules for air quality to include enforceable SO₂ emission limits for the smelter and associated units, including molybdenite heat treaters, the refinery, and the on-site power plant. RACT was applied to low-level emission sources and fugitive emissions.

As SO₂ is a known precursor to PM₁₀ formation, additional efforts were made to reduce SO₂ emissions as part of the 1991 PM₁₀ SIP. During this period Kennecott implemented further enhancements to the smelting operation, which included replacing the Noranda smelter with flash furnace technology, installing a flash-converting furnace, and upgrading to a double-contact acid plant. These modifications significantly reduced the allowable SO₂ emissions from the main stack from 18,200 lbs/hr to 3,204 lbs/hr.

Table 10 presents Kennecott's emissions from various operational units along with the original 1979 emission inventory. Original emissions are then compared side by side with their federally enforceable emission limits set by the 1981 SO₂ SIP and the 1991 PM₁₀ SIP. A drastic reduction in emissions can be observed at Kennecott from 1979 to 1999 as part of the SIP efforts.

Table 10: Historical SIP enforceable emissions reduction from Kennecott operations

Sources	1979 Emissions* (tpy)	Limits	1981 SO ₂ SIP Limits~	1990 Emissions** (tpy)	1991 PM ₁₀ SIP Limits~	1999 Emissions+ (tpy)
Main Stack	67,900	None	79,700 tpy	22,382	14,200 tpy	629.8
Smelter Fugitives	16,500	None	RACT	4,380	RACT	157.7
Utah Power Plant	4,759	None	0.48 lb/MMBtu	2,905	0.52 lb/MMBtu	2,786.10
Magna Molybdenum Heat Treater	1,988	None	608 tpy	NA	Discontinued	NA
Arthur Molybdenum Heat Treater	1,988	None	608 tpy	NA	Discontinued	NA
Copperton Molybdenum Heat Treater	NA	NA	NA	0.7	115 tpy	0.1
Refinery	1,512	None	512 tpy	4.2	None	0.4
Total	94,647			29,672		3,574

* The 1979 inventory was compiled as part of the 1981 SO₂ SIP revision.

** The 1990 inventory represents the period between the first round of smelter modifications and the second round, which coincided with the PM₁₀ SIP.

+ The 1999 inventory represents the period after the second smelter modification.

- The 1981 SIP tpy limits were expressed in lbs/hr (18,200 annual average at the main stack, 139 lbs/hr at each Heat Treater, and 117 lbs/hr at the refinery).

⁵³ Utah State Implementation Plan, Section 4.3.2. Regulation for Control of Main Stack SO₂ Emissions (Kennecott Mineral Company), August 16, 1981.

~ The 1991 SIP limits come from the PM₁₀ SIP. The tpy limits were expressed in lbs/hr (3,240 lbs/hr annual average at the main stack, 26.2 lb.hr for the Heat Treater at the Copperton Concentrator).

(2) Other Emissions Reductions Measures

As part of the 1992 SO₂ SIP, the State also made significant revisions to Utah Administrative Code Rule R307-203 which regulates sulfur content in fuels (coal, fuel oil, and/or fuel mixtures) from stationary sources. The rule established more stringent emissions standards which stated sulfur emissions shall contain no more than 1.0 lb/MMBtu heat input for any mixture of coal nor 0.85 lb/MMBtu heat input for any oil. In addition, the rule introduced a 24-hour averaging period for determining the sulfur content of these fuels and standardized testing procedures. As SO₂ is considered a precursor pollutant to PM₁₀, PM_{2.5}, and Regional Haze, the State has identified and implemented various emissions reduction measures in the respective SIPs. The SO₂ control measures implemented under Utah SIPs are tabulated below.

Table 11: SIP enforceable SO₂ control measures

Company/Sources	SO ₂ Control Measures	Quantified Reduction
2002 PM₁₀ SIP (Approved)⁵⁴		
Geneva Steel Process	Annual emissions reduced from 1449.3 tpy to 560.2 tpy	889.1 tpy
All Refineries in Salt Lake County and Davis County	Installation of Sulfur Recovery Units (SRU)	95% efficiency
	Restrictions on the burning of liquid fuel oil	
	Low-SO _x catalyst emission reduction techniques	Maximum of 9.8 lbs SO ₂ /1000 lbs coke burn-off
	CEM shall meet the requirements of rule R307-170.	
AMOCO, Flying-J, and Crysens	Emission limits for low process flares	
Flying-J and Crysens	Use of low sulfur content crude	Maximum of 0.24% by weight
Utah County	Ban on all forms of residential coal burning	30% reduction
	Installer and operator training programs for residential solid fuel burning devices	5% reduction
	Solid fuel burner inspection program	5% reduction
2014 Moderate Area PM_{2.5} SIP (Approved) - 2015 attainment year data		

⁵⁴ Utah State Implementation Plan, Section IX, Part A, PM₁₀, <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=551009&eqdocs=%20DAQ-2025-000622&dbid=0&repo=Public>.

Salt Lake City, UT ⁵⁵	R307-302, Solid fuel burning devices	19.16 tpy reduced
	R307-356, Appliance pilot light	1.10 tpy reduced
Provo, UT ⁵⁶	R307-302, Solid fuel burning devices	4.02 tpy reduced
	R307-356, Appliance pilot light	0.19 tpy reduced
Logan, UT ⁵⁷	R307-302, Solid fuel burning devices	2.01 tpy reduced
	R307-356, Appliance pilot light	~0.19 tpy reduced
2019 Serious Area PM_{2.5} SIP (Approved) - 2019 attainment year data ⁵⁸		
Salt Lake City	R307-208, Outdoor Wood Boilers	1.06 tpy reduced
	R307-356, Appliance pilot light	7.88 tpy reduced
	R307-302, Solid fuel burning devices	24.09 tpy reduced
IX.H.1-H.4: PM₁₀ Emission Limits ⁵⁹		
Stack Testing	Stack tests should be performed in accordance with 40 CFR 60, Appendix A, Method 2, 6C, and 19.	
Fluid Catalytic Cracking Units (FCCU)	FCCUs shall comply with an SO ₂ emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.	
Refinery Fuel Gas	Reduce H ₂ S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a.	
Sulfur Recovery Units (SRU)	SRUs shall be at least 95% effective in removing sulfur and meet limitations listed in 40 CFR 60.102a(f)(1) or 60.102a(f)(2).	
	Amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).	
Liquid Fuel Oil	Liquid fuel oil shall not be allowed to burn in stationary sources except during natural gas curtailments.	
	Diesel fuel shall meet the specification of 40 CFR 1090.305.	
Hydrocarbon Flares	Flares are subject to NSPS Subpart Ja.	

⁵⁵ Utah State Implementation Plan, Section IX, Part A.21, PM_{2.5},
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=479906&eqdocs=%20DAQ-2024-011602>.

⁵⁶ Utah State Implementation Plan, Section IX, Part A.22, PM_{2.5},
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=479904&eqdocs=%20DAQ-2024-011604>.

⁵⁷ Utah State Implementation Plan, Section IX, Part A.23, PM_{2.5},
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=479910&eqdocs=%20DAQ-2024-011601>.

⁵⁸ Utah State Implementation Plan, Section IX, Part A.31, PM_{2.5},
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=385732&eqdocs=%20DAQ-2019-005386>.

⁵⁹ Utah State Implementation Plan, Section IX, Part H,
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=560211&eqdocs=%20DAQ-2025-001221&dbid=0&repo=Public>.

	Install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c) or limit flaring during normal operations to 500,000 scfd for each affected flare.	
Big West Oil Company	Source-wide SO ₂ cap	Not to exceed 0.60 tons per day (tpd) and 140 ton per rolling 12-month period
	Alternate Startup and Shutdown Requirements	Combined emissions of SO ₂ shall not exceed 1.2 tpd
	The total number of days which include startup or shutdown of the FCCU shall not exceed ten (10) per 12-month rolling period.	
	Refinery flares shall meet Subpart Ja and MACT CC flaring standards.	
	Product loading racks shall be controlled by vapor recovery and vapor combustors.	
	Interim Emission Limits: Combined emissions of SO ₂ from all external combustion process equipment between October 1 - March 31	Not to exceed 2.764 tpd
	Interim Emission Limits: Combined emissions of SO ₂ from all external combustion process equipment between April 1 - September 30	Not to exceed 3.639 tpd
Chevron Products Company	Source-wide SO ₂ cap	Not to exceed 1.05 tpd and 383.3 tons per rolling 12-month period
	Sulfur Recovery Unit #1 and #2 shall be controlled by a tail gas treatment unit and tail gas incineration.	
	Flare #1 and #2 shall be controlled by a flare gas recovery system.	
	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment.	Not to exceed 0.5 tpd
Hexcel Corporation	Natural gas consumption	Not to exceed 5.50 MMscf per day

Holly Refining and Marketing Company	Source-wide SO ₂ cap	Not to exceed 0.31 tpd and 110.3 tons per rolling 12-month period
	Sulfur recovery unit shall be controlled by tail gas incineration.	
	Interim Emission Limits: Combined emissions of SO ₂ from all sources	Not to exceed 4.714 tpd
Kennecott Utah Copper	Diesel-powered ore and waste haul trucks	Not to exceed 30,000 miles per day
	Smelter Main Stack (Stack #11) emission	Not to exceed 552 lbs/hr 3-hour rolling average
		Not to exceed 422 lbs/hr daily average
	Main Stack (Stack #11) shall have SO ₂ CEMs installed and meet the requirements of rule R307-170.	
	Power Plant Unit #4 shall only use natural gas as fuel, unless the supplier or transporter of natural gas imposes a curtailment.	
	Sulfur content of any fuel burned	Not to exceed 0.66 lbs of sulfur per MMBtu per test
Tesoro Refining & Marketing Company	Source-wide SO ₂ cap	Not to exceed 3.8 tpd and 300 tons per rolling 12-month period
	SRU/TGTU/TGI	Not to exceed 1.68 tpd for up to 21 days per rolling 12-month period and 0.69 tpd for the remainder of the rolling 12-month period
	North and South Flares shall be controlled by a flare gas recovery system.	
	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment between November 1 - End of February	3.699 tpd
	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment between March 1 - October 31	4.374 tpd
Gadsby Power Plant	Steam generating units #1, #2, #3 shall only use natural gas as fuel, unless the supplier or transporter of natural gas	

	imposes a curtailment and for maintenance firings.	
Brigham Young University	Central Heating Unit #2, #3 and #5	Not to exceed 597 ppm (7% O ₂ dry)
	Central Heating Plant Coal-Fired Boilers	Not to exceed 0.54 lbs of sulfur per MMBtu or 0.60% by weight
	Inspect fuel sulfur weight % and fuel heating value by submitting a coal sample to a laboratory using methods of ASTM, or inspecting vendor documentation.	
IX.H.11-H.13: PM_{2.5} Emission Limits ⁶⁰		
Stack Testing	Stack tests should be performed in accordance with 40 CFR 60, Appendix A, Method 2, 6C, and 19.	
Fluid Catalytic Cracking Units (FCCU)	FCCUs shall comply with an SO ₂ emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.	
Refinery Fuel Gas	Reduce H ₂ S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a.	
Hydrocarbon Flares	Flares are subject to NSPS Subpart Ja.	
	Install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c) or limit flaring during normal operations to 500,000 scfd for each affected flare.	
Liquid Fuel Oil	Liquid fuel oil shall not be allowed to burn in stationary sources except during natural gas curtailments.	
	Diesel fuel shall meet the specification of 40 CFR 1090.305.	
Big West Oil Company	Alternate Startup and Shutdown	Combined emissions of SO ₂ shall not exceed 1.2 tpd
	The total number of days which include startup or shutdown of the FCCU shall not exceed ten (10) per 12-month rolling period.	
	Refinery flares shall meet Subpart Ja and MACT CC flaring standards.	

⁶⁰ Utah State Implementation Plan, Section IX.H.11-H.13,
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=585532&eqdocs=%20DAQ-2025-001223>.

	Product loading racks shall be controlled by vapor recovery and vapor combustors.	
Chevron Products Company	Sulfur Recovery Units #1 and #2 shall be controlled by a tail gas treatment unit and tail gas incineration.	
	Flare #1 and #2 shall be controlled by a flare gas recovery system.	
Hexcel Corporation	Natural gas consumption	Not to exceed 5.50 MMscf per day
HF Sinclair Woods Cross Refinery	Refinery flares shall be controlled by flare gas recovery system.	
	Sulfur recovery unit shall be controlled by tail gas incineration.	
Kennecott Utah Copper	Diesel-powered ore and waste haul trucks	Not to exceed 30,000 miles per day
	Power Plant Unit #4 shall only use natural gas as fuel, unless the supplier or transporter of natural gas imposes a curtailment.	
	Smelter Main Stack (Stack #11) SO ₂ emission	Not to exceed 552 lbs/hr 3hr. rolling average
		Not to exceed 422 lbs/hr daily average
	The Main Stack (Stack #11) shall have SO ₂ CEMs installed and meet the requirements of R307-170.	
	Electric Arc Furnace Baghouse shall have CEM installed and meet the requirements of R307-170.	
Nucor Steel Mills	SO ₂ emission	Not to exceed 93.98 lbs/hr 3-hour rolling average
		Not to exceed 89.00 lbs/hr daily average
Tesoro Refining & Marketing Company	SRU/TGTU/TGI	Not to exceed 1.68 tpd for up to 21 days per rolling 12-month period and 0.69 tpd for the remainder of the rolling 12-month period
	North and South Flares shall be controlled by flare gas recovery system.	
	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment between November 1 - End of February	3.699 tpd

	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment between March 1 - October 31	4.374 tpd
Gadsby Power Plant	Steam generating unit #1, #2, #3 shall only use natural gas as fuel, unless the supplier or transporter of natural gas imposes a curtailment or for maintenance firings.	
University of Utah	Boilers #1, #3, and #4 natural gas usage	Not to exceed 530 MMscf per calendar year
Brigham Young University	Central Heating Unit #2, #3 and #5	Not to exceed 597 ppm (7% O ₂ dry) lbs/hr
	Sulfur content of central heating plant coal-fired boilers	Not to exceed 0.54 lbs/MMBtu
	Inspect fuel sulfur weight % and fuel heating value by submitting a coal sample to a laboratory.	

1
2

iv. State has Met Requirements of Section 110 and Part D

CAA 107(d)(3)(E)(v) – The State containing such area has met all requirements applicable to the area under section 110 and part D. Section 110 of the Act deals with the broad scope of the state implementation plans and the capacity of the respective state agency to effectively administer such a plan. Part D deals specifically with plan requirements for nonattainment areas, including those requirements that are specific to SO₂.

(1) Section 110

The State has met all requirements applicable to the SLC NAA area under Section 110 of the CAA. Section 110(a)(2) contains the general requirements or infrastructure elements necessary for EPA approval of the SIP. On June 2, 2013, the State submitted an Infrastructure SIP to the EPA demonstrating compliance with the requirements of Section 110 that are applicable to the 2010 SO₂ NAAQS.⁶¹ The EPA approved the State’s Infrastructure SIP on October 22, 2018 (83 FR 47566) for all Section 110 requirements that are applicable to redesignation.⁶²

(2) Part D Subpart 1 and 5

Part D of the CAA addresses “Plan Requirements for Nonattainment Areas.” Subparts 1 and 5 of Part D contain planning elements that must be included in the SIP. This includes emissions inventories, control measures (including reasonably available control technology), permits for major new or modified sources, enforceable emissions limits, schedules of compliance, and contingency measures if progress is inadequate. On May 15, 1992, the State submitted a revised SO₂ SIP adequately addressing each of the above-mentioned elements. The SIP was fully approved by the EPA on December 14, 1994, which suggests Utah has complied with all applicable Part D requirements.⁶³

v. Maintenance Plan

As stated in the CAA, an area may not be redesignated to attainment without first submitting and receiving EPA approval of a maintenance plan. The maintenance plan is a quantitative analysis showing that the area will continue to attain the NAAQS for an additional 10 years (from EPA

⁶¹ State of Utah 110(a)(2) SIP Infrastructure Elements for SO₂ (2013), <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=572027&eqdocs=%20DAQ-2025-002449&dbid=0&repo=Public>.

⁶² Air Quality State Implementation Plans, Approvals and Promulgations: Infrastructure Monitoring Requirements for the 2008 Pb, 2010 SO₂, 2010 NO₂ and 2012 PM_{2.5} National Ambient Air Quality Standards, Utah, October 22, 2018, <https://www.federalregister.gov/documents/2018/09/20/2018-20448/air-quality-state-implementation-plans-approvals-and-promulgations-infrastructure-monitoring>.

⁶³ Approval and Promulgation of State Implementation Plans, Utah Stack Height Analyses and Regulations, December 14, 1994, 59 FR 18341, www.federalregister.gov/documents/search?conditions%5Bterm%5D=59+FR+18341.

approval), accompanied by sufficient assurance that the terms of the numeric demonstration will be administered by the State and by the EPA in an oversight capacity. The maintenance plan is the central criterion for redesignation. It is contained in the following Section.

IX.B.11.d Maintenance Plan

CAA 107(d)(3)(E)(iv) – *The administrator has fully approved a maintenance plan for the area as meeting the requirements of section 175A.* An approved maintenance plan is one of several criteria necessary for area redesignation as outlined in Section 107(d)(3)(E) of the CAA. The maintenance plan itself, as described in Section 175A of the CAA and further addressed in EPA guidance⁶⁴, has its own list of required elements. The following table is presented to summarize these requirements. Each will then be addressed in turn.

Table 12: Maintenance Plan Requirements in the Federal Clean Air Act

Category	Requirement	Reference	Addressed in Section
Maintenance Demonstration	Provide for maintenance of the relevant NAAQS in the area for at least 10 years after redesignation.	CAA §175A(a)	IX.B.11.d(i)
Revise in 8 Years	The State must submit an additional revision to the plan, 8 years after redesignation, showing an additional 10 years of maintenance.	CAA §175(b)	IX.B.11.d(ii)
Continued Implementation of Nonattainment Area Control Strategy	The CAA requires continued implementation of the nonattainment area control strategy unless such measures are shown to be unnecessary for maintenance or are replaced with measures that achieve equivalent reductions.	CAA §175A(c), Calcagni memo	IX.B.11.d(iii)
Contingency Measures	Areas seeking redesignation from nonattainment to attainment are required to develop contingency measures that include State commitments to implement additional control measures in response to future violations of the NAAQS.	CAA §175A(d)	IX.B.11.d(iv)

⁶⁴ John Calcagni, September 4, 1992, EPA Memorandum “Procedure for Processing Requests to Redesignate Areas to Attainment” https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf

Category	Requirement	Reference	Addressed in Section
Verification of Continued Maintenance	The maintenance plan must indicate how the State will track the progress of the maintenance plan.	Calcagni memo	IX.B.11.d(v)

1 i. Demonstration of Maintenance – Attainment Inventory

2 *CAA 175A(a) – Each State which submits a request under Section 107(d) for redesignation of a*
3 *nonattainment area as an area which has attained the NAAQS shall also submit a revision of the*
4 *applicable implementation plan to provide for maintenance of the NAAQS for at least 10 years*
5 *after the redesignation. The plan shall contain such additional measures, if any, as may be*
6 *required to ensure such maintenance.* The maintenance demonstration is discussed in the EPA
7 guidance⁶⁵ as one of the core provisions that should be considered by the states for inclusion in a
8 maintenance plan.

9
10 According to the EPA guidance, a state may generally demonstrate maintenance of the NAAQS
11 by either showing that future emissions of a pollutant or its precursors will not exceed the level
12 of the attainment inventory or by modeling to show that the future mix of sources and emission
13 rates will not cause a violation of the NAAQS.

14
15 As discussed in Section IX.B.11.c(i)(2) – Modeling Element of this document, Utah has
16 provided a modeling demonstration evaluating continued attainment of the NAAQS using the
17 highest allowable emissions from six point sources in and near the nonattainment area. In
18 addition to that analysis, Utah is providing an attainment inventory-based demonstration of
19 maintenance. Under this approach, projected future emissions at the highest allowable levels are
20 compared to the base-year attainment inventory to show that the emissions are expected to
21 remain at or below levels consistent with continued attainment.

22
23 Consistent with the guidance, the projection inventory should consider future growth, including
24 population and industry, should be consistent with the base-year inventory, and should document
25 data inputs and assumptions. Any assumption concerning emission rates must reflect permanent,
26 enforceable measures.

27
28 The Division chose 2023 as the base year for inventory analysis presented in this section because
29 it was the most recent triennial inventory year available for all source categories. The base-year

⁶⁵ John Calcagni, September 4, 1992, EPA Memorandum “Procedure for Processing Requests to Redesignate Areas to Attainment” https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf.

emissions inventory is a comprehensive, accurate, and current inventory of actual emissions for all sources in the nonattainment area plus any sources located outside the nonattainment area that may affect attainment.⁶⁶ The 2023 base-year emissions inventory is projected to 2040 to demonstrate maintenance of the NAAQS. The year 2040 is chosen to allow at least 10 years of maintenance period after final EPA redesignation. The emissions contained in the inventories include sources located in Salt Lake and Tooele counties.⁶⁷ Emissions from three point sources in Davis County (adjacent to Salt Lake County) are also included in the maintenance demonstration.⁶⁸ These sources were determined to be significant by the EPA for the attainment demonstration and were therefore included in both the modeling analysis and the inventory projection.

There are four general categories of sources included in the inventory: point source, area source, on-road mobile source, and non-road mobile source. All inventories are developed in accordance with the Air Emissions Reporting Requirements (40 CFR Part 51, Subpart A). Emissions recorded for each sector are presented in tons per year.

The point source category consists of all stationary sources subject to Utah Emissions Inventory Reporting Rule R307-150, including both major (>100 tpy) and minor (<100 tpy) SO₂ emission sources in Salt Lake and Tooele counties.⁶⁹ Stationary sources that are not subject to Rule R307-150 are classified under the area source category. The area source category also includes emissions estimates for sources that are individually too small to be reported as point sources but collectively contribute to total SO₂ emissions within the SO₂ nonattainment areas. Notable examples include combustion activities, agricultural burning, and wildfires.

On-road mobile sources include emissions from motorized vehicles that typically operate on public roadways, such as passenger vehicles, light-duty trucks, heavy-duty trucks, and buses. Non-road mobile sources include yard care equipment, construction equipment, recreational engines, and portable industrial, commercial, and agricultural engines. Emissions from both on-road and non-road mobile sources were developed using the EPA-approved Motor Vehicle Emission Simulator, version 5 (MOVES5).⁷⁰

Emissions inventory Table 13 shows baseline point source emissions from 1979 which were compiled as part of the 1981 SO₂ SIP effort.⁷¹ Area source emissions were projected to 2040

⁶⁶ Table 13, 14, and 15 of this document.

⁶⁷ Table 13: SO₂ emissions inventory for Salt Lake and Tooele counties by source category in tons per year.

⁶⁸ Table 14 and 15 of this document.

⁶⁹ R307-150 Emissions Inventory

<https://adminrules.utah.gov/public/rule/R307-150/Current%20Rules?searchText=R307-150>.

⁷⁰ MOVES5 5.0.1-movesdb20241112

<https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves>.

⁷¹ 1979 Baseline Emissions Inventory, 1981 SO₂ SIP,

from the 2023 triannual inventory. Growth data from appropriate data sources, including information from the Governor's Office of Management and Budget, was used for the projection. Point source emissions are represented as the actual emissions from the 2023 triannual emissions inventory. Point sources were grown from 2023 to 2040 on a case-by-case basis for the projection inventories. On-road and non-road mobile source emissions were projected using MOVES5.

Table 13: SO₂ emissions inventory for Salt Lake and Tooele counties by source category in tons per year

Nonattainment Area Inventory Projection (tpy) ⁺												
	1979	1996	1999	2002	2005	2008	2011	2014	2017	2020	2023	2040
Area Sources	*	41.10	1,162.81	292.67	158.54	200.43	595.85	23.65	146.84	192.51	150.51	158.36
Non-Road Mobile	*	198.52	*	536.67	583.13	353.24	247.16	130.25	183.34	2.99	168.75	226.94
On-Road Mobile	*	0.00	927.36	855.61	608.61	86.35	120.84	103.82	108.60	32.19	33.65	18.60
Point Source**	112,994.17	4,959.54	5,108.81	4,771.65	4,998.86	5,955.08	3,467.53	3,076.37	2,250.27	631.55	560.15	588.35
Total	112,994.17	5,199.16	7,198.98	6,456.60	6,349.14	6,595.10	4,431.38	3,334.09	2,689.05	859.24	913.06	992.25

*Data not available

⁺Does not include emissions from Davis County sources

Total SO₂ emissions in the Utah SO₂ nonattainment area have declined dramatically since 1979, decreasing from approximately 113,000 tpy to about 913 tpy in 2023, representing a reduction of more than 99%. Early emissions were dominated by large industrial point sources, which accounted for nearly all SO₂ emissions in 1979. Substantial reductions occurred through the 1980s and 1990s as major facilities implemented enforceable emission limits and control technologies. Continued declines after 2000 reflect additional controls, operational changes, and improved compliance with federal and state permitting requirements. Since 2023, point sources remain the primary contributors but at significantly reduced levels, while area, on-road mobile, and non-road mobile sources collectively contribute a relatively small portion of total emissions.

The observed reductions are primarily attributed to implementation of the approved SIPs⁷², which required the application of RACT under moderate SIP and Best Available Control Technology under serious SIP and facility-specific emission limits⁷³ for major SO₂ sources. Additional reductions resulted from federal fuel sulfur standards and mobile-source regulations

<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=612086&dbid=0>.

⁷² Utah State Implementation Plans, <https://deq.utah.gov/air-quality/sections-state-implementation-plan-sip>.

⁷³ SO₂ Maintenance Plan, Table 11: SIP enforceable SO₂ control measures.

1 that substantially lowered sulfur content in fuels^{74, 75}, leading to near elimination of SO₂
2 emissions from on-road engines. Changes in the petroleum refinery industry, including fuel
3 switching and installation of sulfur control equipment, further contributed to long-term emission
4 decreases.⁷⁶

5
6 Between 2023 and 2040, total SO₂ emissions in the nonattainment area are projected to increase
7 modestly from 913.06 tpy to 992.25 tpy (approximately 9%), while remaining substantially
8 below historical levels associated with prior nonattainment. Point source actual emissions, which
9 constitute the largest share of the inventory, are projected to increase slightly from 560.15 tpy in
10 2023 to 588.35 tpy in 2040 due to anticipated industrial activity and economic growth. However,
11 emissions from these sources remain subject to permanent and federally enforceable permit
12 limits established in facility Approval Orders. These limits represent the maximum allowable
13 emissions for each facility and are not expected to increase by 2040. The projected 2040 point
14 source emissions of 588.35 tpy remain well below the facility-wide maximum allowable
15 emission limits used in the attainment modeling.⁷⁷ This relationship demonstrates that even with
16 modest growth in actual emissions, emissions remain within the bounds evaluated in the
17 attainment demonstration.

18
19 Non-road mobile source emissions are projected to increase from 168.75 tpy to 226.94 tpy,
20 largely attributable to projected growth in airport-related activity within the non-road sector. In
21 contrast, on-road mobile source emissions are projected to decline from 33.65 tpy to 18.60 tpy as
22 a result of continued fleet turnover and implementation of federal vehicle emission standards and
23 ultra-low sulfur fuel requirements. Area source emissions are projected to increase slightly from
24 150.51 tpy to 158.36 tpy, consistent with anticipated population and commercial growth.

25
26 Emissions projections through 2040 indicate that total SO₂ emissions are expected to remain low
27 and stable under existing regulatory programs, providing assurance that the maintenance area
28 will continue to comply with the current SO₂ NAAQS which is considerably more stringent than
29 the 1971 standards.⁷⁸ These trends demonstrate that the emission reductions are permanent,
30 surplus, and enforceable, and that the proposed maintenance area is well positioned to maintain
31 attainment throughout the maintenance period.

74 1090.205 Sulfur standards, 40 CFR 1090.205, <https://www.ecfr.gov/current/title-40/section-1090.205>.

75 ULSD Standards, 40 CFR 1090.305, <https://www.ecfr.gov/current/title-40/section-1090.305>.

76 Standards of Performance for Petroleum Refineries, 40 CFR Part 60 Subpart Ja,
<https://www.ecfr.gov/current/title-40/part-60/subpart-Ja>.

77 Section IX.B.11.c(i)(2) The Area Has Attained the 1971 SO₂ NAAQS: Modeling Element

78 SO₂ NAAQS, <https://www.epa.gov/so2-pollution/timeline-sulfur-dioxide-naaqs>.

- 1 Table 14: 2023 actual, 2040 projected, and maximum allowable SO₂ emissions for six explicitly
 2 modeled sources. Maximum allowable emission limits are held constant between 2023 and 2040.

Explicitly Modeled Sources	2023 Actual Emissions	2040 Projected Emissions	2023 & 2040 Maximum Allowable Emission Limits
Kennecott Smelter and Refinery	429.49	442.66	1,090.27
Gadsby Power Plant	1.16	0.88	75.00
Tesoro Refinery	17.60	18.14	300.01
Chevron Refinery*	37.58	38.73	384.70
Big West Refinery*	70.54	72.70	140.14
HF Sinclair Refinery*	12.17	12.55	84.10
Total	568.54	585.66	2,074.22

3 *Located in Davis County.
 4

5 Table 14 summarizes 2023 actual SO₂ emissions and projected 2040 emissions for the six
 6 explicitly modeled stationary sources⁷⁹ in and near the nonattainment area, along with their
 7 maximum allowable emission limits. In 2023, total actual emissions from these sources were
 8 568.54 tpy. Emissions are dominated by the Kennecott Smelter and Refinery (429.49 tpy), with
 9 the remaining facilities contributing comparatively smaller amounts. The combined maximum
 10 allowable emission limits for these six sources are 2,074.22 tpy, indicating that actual emissions
 11 are well below allowable levels and that significant compliance margins exist for each facility.
 12

13 Projected 2040 emissions total 585.66 tpy, representing a modest increase of approximately 3%
 14 from 2023 actual emissions inventory levels. Individual facility projections show only minor
 15 changes, and total maximum allowable emission limits remain unchanged through 2040. Overall,
 16 projected emissions remain substantially below the maximum allowable emission limits.
 17

18 The dispersion modeling conducted for the attainment demonstration used 2023 maximum
 19 allowable emission limits and the results show that the area meets the applicable SO₂ NAAQS.
 20 Emissions from these six explicitly modeled sources represent the primary contributors of SO₂,
 21 while all other emission sources in the nonattainment area accounted for in the background
 22 concentration used in the modeling analysis. Because 2040 maximum allowable emission limits
 23 remain unchanged and are comparable to the emissions levels used in the attainment modeling,
 24 similar dispersion modeling results would be expected under 2040 conditions. These data
 25 support the conclusion that SO₂ emissions from explicitly modeled sources are expected to
 26 remain stable over the maintenance period and that continued maintenance of the SO₂ NAAQS
 27 through 2040 is reasonably assured. Facility-wide maximum allowable emission limits and
 28 compliance with NAAQS have been discussed in detail in the modeling chapter in Section
 29 IX.B.11.c(i)(2) which supports the same conclusion.

⁷⁹ Section IX.B.11.c(i)(2) The Area Has Attained the 1971 SO₂ NAAQS: Modeling Element

1 Table 15: Triennial actual SO₂ emissions inventory for six explicitly modeled sources covering
 2 1996–2023, with forward projections from 2023 through 2040.

	1996	1999	2002	2005	2008	2011	2014	2017	2020	2023 Base- year	2040 Projection
Kennecott Smelter and Refinery	1,555.30	789.19	938.75	777.27	970.08	696.89	703.14	587.95	428.87	429.49	442.66
Gadsby Power Plant	0.60	1.70	1.90	0.56	1.95	0.81	1.52	0.46	0.59	1.16	0.88
Tesoro Refinery	982.63	1107.10	712.12	879.66	931.90	795.31	708.30	499.46	22.56	17.60	18.14
Chevron Refinery*	1,115.60	791.93	1,332.00	2,200.66	591.85	24.31	23.89	32.38	37.65	37.58	38.73
Big West Refinery*	573.87	441.66	272.48	360.77	377.39	188.71	57.14	55.43	50.63	70.54	72.70
HF Sinclair Refinery*	864.05	787.67	451.90	574.09	452.99	131.03	102.33	44.35	20.04	12.17	12.55
Total	5,092.05	3,919.25	3,709.15	4,793.01	3,326.16	1,837.06	1,696.32	1,220.03	560.34	568.54	585.66

3 *Located in Davis County.

4
 5 Table 15 provides another look at the long-term emission trends, the magnitude of reductions
 6 achieved, and the stability of emissions inventory through the maintenance period. The table
 7 presents triennial actual SO₂ emissions for the six explicitly modeled stationary sources from
 8 1996 through 2023, along with projected emissions through 2040. The data show a substantial
 9 long-term downward trend in emissions across the nonattainment area. Total emissions declined
 10 from 5,002.05 tpy in 1996 to 568.54 tpy in the 2023 base year, representing an overall reduction
 11 of approximately 89%. The most significant reductions occurred between 2008 and 2017 and are
 12 primarily attributable to process changes, fuel switching, installation of control technologies, and
 13 enforceable AO limits at the point source facilities.

14
 15 Emissions have remained relatively stable in recent years, with totals of 560.34 tpy in 2020 and
 16 568.54 tpy in 2023. Projected emissions for 2040 are 585.66 tpy, reflecting only a modest
 17 increase over the base-year of 2023. Individual facility projections show minor changes, and
 18 overall emissions remain far below historical levels and facility-wide maximum allowable
 19 emission limits. The long-term downward trend and the stability of recent and projected
 20 emissions inventory further support the conclusion that the area has attained the SO₂ NAAQS
 21 and is expected to continue to maintain the standard through 2040.

1 **ii. Revise in Eight Years**

2 *CAA 175A(b) – 8 years after redesignation of any area as an attainment area, the State shall*
3 *submit an additional revision of the applicable plan for maintaining the national primary*
4 *ambient air quality standard for 10 years after the expiration of the 10-year period. Utah*
5 *commits to submit a revised maintenance plan eight years after the EPA takes final action*
6 *redesignating Salt Lake County area to attainment, as required by the CAA.*

7 **iii. Nonattainment Requirements Applicable Pending Plan Approval**

8 *CAA 175A(c) – Until such plan revision is approved and an area is redesignated as attainment,*
9 *the requirements of CAA Part D, Plan Requirements for Nonattainment Areas, shall remain in*
10 *force and effect. The CAA requires the continued implementation of the nonattainment area*
11 *control strategy unless such measures are shown to be unnecessary for maintenance or are*
12 *replaced with measures that achieve equivalent reductions. Utah will continue to implement the*
13 *emissions limitations and measures from the SO₂ SIP.*

14 **iv. Contingency Plan**

15 *CAA 175A(d) – Each maintenance plan shall contain contingency measures to assure that the*
16 *State will promptly correct any violation of the standard which occurs after the redesignation of*
17 *the area to attainment. Such provisions shall include a requirement that the State will implement*
18 *all control measures which were contained in the SIP prior to redesignation.*

19
20 The contingency plan must also ensure that the contingency measures are adopted expeditiously
21 once triggered. The primary elements of the contingency plan are: 1) the list of potential
22 contingency measures; 2) the tracking and triggering mechanisms to determine when
23 contingency measures are needed; and 3) a description of the process for recommending and
24 implementing the contingency measures.

25 **Tracking**

26 The tracking plan for the Salt Lake County and part of Tooele County nonattainment area
27 consists of monitoring and analyzing ambient SO₂ concentrations. In accordance with 40 CFR
28 58, the State will continue to operate and maintain an adequate SO₂ monitoring network in the
29 nonattainment area.

30 **Triggering**

31 Triggering of the contingency plan does not automatically require a revision to the SIP, nor does
32 it mean that the area will automatically be redesignated once again to nonattainment. Instead, the
33 State will have an appropriate timeframe to correct the potential violation with implementation

1 of one or more adopted contingency measures. In the event that violations continue to occur,
2 additional contingency measures will be adopted until the violations are corrected.

3
4 Upon notification of a potential violation of the SO₂ NAAQS, the State will develop appropriate
5 contingency measures intended to prevent or correct violation of the standard. Information about
6 historical exceedances of the standard, the meteorological conditions related to the recent
7 exceedances, and the most recent estimates of growth and emissions will be reviewed. The
8 possibility that an exceptional event occurred will also be evaluated.

9
10 Upon monitoring a potential violation of the SO₂ NAAQS, including exceedances flagged as
11 exceptional events but not concurred with by EPA, the State will identify a means of corrective
12 action within six months after a potential violation. The maintenance plan contingency measures
13 will be chosen from the following list based on consideration of cost-effectiveness, emission
14 reduction potential, economic and social considerations, or other factors that the State deems
15 appropriate:

- 16 • Re-evaluate the permissible sulfur content of fuels for commercial and industrial sources,
17 as established in Rule R307-203.
- 18 • Further controls on the stationary sources in the nonattainment area that are listed below:
 - 19 ○ Kennecott Smelter and Refinery;
 - 20 ○ Gadsby Power Plant;
 - 21 ○ Tesoro Refinery;
 - 22 ○ Chevron Refinery;
 - 23 ○ Big West Refinery; and
 - 24 ○ HF Sinclair Refinery.

25
26 The State will then hold a public hearing to consider the contingency measures identified to
27 address the potential violation. The State will require implementation of such corrective action
28 no later than one year after the violation is confirmed. Any contingency measures adopted and
29 implemented will become part of the next revised maintenance plan submitted to the EPA for
30 approval.

31 v. Verification of Continued Maintenance and Monitoring

32 Implicit in the requirements outlined above is the need for the State to determine whether the
33 area is in fact maintaining the standard it has achieved. There are two complementary ways to
34 measure this: 1) by monitoring the ambient air for SO₂; and 2) by inventorying emissions of SO₂
35 from various sources.

36
37 The State will continue to maintain an ambient monitoring network for SO₂ in accordance with
38 40 CFR Part 58 and the Utah SIP. The State anticipates that the EPA will continue to review the

1 ambient monitoring network for SO₂ each year, and any necessary modifications to the network
2 will be implemented.

3
4 Additionally, the State will track new and modified stationary source permits. If the resulting
5 emissions change significantly over time, the State will perform appropriate studies to determine:
6 1) whether additional and/or re-sited monitors are necessary; and 2) whether stationary source
7 emission projections are on target. The State will also continue to collect actual emissions
8 inventory data from sources at thresholds defined in Rule R307-150 and will review and update
9 the annual emissions inventory for the nonattainment area at a minimum of once every three
10 years to ensure continued maintenance of the SO₂ standard.

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4
5 UTAH STATE IMPLEMENTATION PLAN

6 **SO₂ Maintenance**
7 **Provisions for the Tooele**
8 **County, UT SO₂ Nonattainment Area**
9

10 SECTION IX.B.12
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Section IX.B.12 SO₂ Maintenance Provisions for Tooele County

IX.B.12.a Introduction

In 1978, the U.S. Environmental Protection Agency (EPA) designated three areas in Utah as nonattainment for the 1971 National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO₂). At that time, the EPA had established three SO₂ standards: a 24-hour primary standard, an annual primary standard, and a 3-hour secondary standard. The three nonattainment areas were:

- Cedar City Nonattainment Area;
- Salt Lake County Nonattainment Area (SLC NAA); and
- Tooele County Nonattainment Area (TC NAA)¹

The EPA approved Utah's SO₂ control strategy for Cedar City on February 19, 1980. However, the strategy for SLC NAA and TC NAA was disapproved. In 1981, Utah submitted a revised SO₂ State Implementation Plan (SIP) for the two counties, which included a redefined nonattainment boundary covering all of Salt Lake County and only the eastern portion of Tooele County above 5,600 feet in elevation.

The EPA granted interim approval of this SIP in 1985, pending resolution of issues related to Good Engineering Practice (GEP) stack height requirements. To address this, Utah submitted its GEP SIP in 1986, followed by additional submittals in 1986, 1987, and 1988. The EPA proposed approval of the GEP SIP in 1988, but final approval was delayed due to public comments, particularly concerning land ownership on elevated terrain, which affected the GEP stack height demonstration.

With the 1990 amendments to the Clean Air Act (CAA), any nonattainment area lacking a fully approved SIP was automatically redesignated as nonattainment and subject to a SIP call. Because the Utah SIP had never received full approval, the State was once again required to submit revised SIPs addressing both:

- GEP stack height; and
- SO₂ control measures.

All other areas in Utah, including Cedar City, were found to have ambient air quality that was "better than the national standards," and thus did not require further SIP revisions. There have been no violations of either the primary or secondary NAAQS for SO₂ in the Utah nonattainment area since 1981. The lack of monitored violations is the result of permanent and enforceable

¹ A portion of the county is located within the area and is designated nonattainment
<https://www3.epa.gov/airquality/greenbook/sncs.html#UT>

1 emission reductions at the emissions points that were responsible for the violations which led to
2 the original nonattainment status.

3
4 Based on this long-standing compliance and in accordance with the CAA Section 107(d)(3)(D),
5 Utah submitted the required SIP revisions in 1991 (for GEP stack height) and 1992 (for SO₂
6 control). The EPA approved both in 1994, bringing Salt Lake County and Tooele County into
7 compliance with federal requirements.

8
9 Salt Lake County and Tooele County have attained the 1971 SO₂ standards. As a result, this
10 section has been added to the SIP to demonstrate that the area is eligible for redesignation to
11 attainment. Under Section 107(d)(3)(E) of the CAA, a nonattainment area is eligible for
12 redesignation when the area has met the following requirements: (1) the area has attained the
13 NAAQS standard; (2) the area has an EPA-approved attainment SIP; (3) the improvement in air
14 quality is due to permanent and enforceable reductions in emissions resulting from
15 implementation of the SIP; (4) the State has met the SIP requirements of Section 110 and Part D
16 of the CAA; and (5) the area has an EPA-approved Maintenance Plan.

17
18 As demonstrated in Subsection IX.B.12.c, the nonattainment area has satisfied the redesignation
19 requirements of Section 107 and is eligible for redesignation pending the EPA's approval of the
20 Tooele County Maintenance Plan. The maintenance plan is included in Subsection IX.B.12.d and
21 is written in compliance with Section 175A of the CAA. The maintenance plan demonstrates that
22 the nonattainment area will continue to maintain the 1971 NAAQS through 2040. The
23 maintenance plan also includes contingency measures to assure that the State will promptly
24 correct any violation of the standard that may occur after the redesignation. In addition to EPA's
25 approval of the maintenance plan, the State is requesting that the TC NAA be redesignated to
26 attainment for the 1971 SO₂ NAAQS.

27 IX.B.12.b History of Nonattainment Area Designation

28 Since the SO₂ nonattainment designations occurred at the same time and involved similar
29 regulatory decisions and control strategies by the EPA and the State, Section IX.B.12.b includes
30 discussion of all three areas to provide historical context and a complete description of Utah's
31 SO₂ SIP development. Although this maintenance plan applies specifically to the TC NAA, the
32 Salt Lake County and Cedar City areas are referenced because they were addressed concurrently
33 in the State's early SO₂ SIP submittals.

1 i) The 1981 SO₂ SIP Submittal

2 In the Federal Register dated March 3, 1978, there were three areas in Utah that were designated
3 as nonattainment for the 1971 SO₂ NAAQS.² These three areas include:

- 4 • SLC NAA;
- 5 • TC NAA; and
- 6 • Cedar City.

7 All three areas were violating the primary 24-hour SO₂ standard of 0.14 parts per million (ppm)
8 not to be exceeded more than once per year, in addition to the secondary 3-hour standard of 0.5
9 ppm not to be exceeded more than once per year. There have not been any recorded violations of
10 the primary annual standard of 0.03 ppm. The designation of Cedar City as a nonattainment area
11 for SO₂, made by the State, was based on ambient air quality data collected at the State's
12 monitoring station on the campus of Southern Utah State College (now Southern Utah State
13 University).³ The designation recommendations of Salt Lake and Tooele counties made by the
14 State were overrode by the EPA, based on data collected at the State's ambient air monitoring
15 stations in Magna and Tooele.²

16
17 The old reverberatory furnace system at the Kennecott Copper Corporation's Utah Smelter
18 (Kennecott) was still in operation at that time. On March 13, 1981, the EPA revised Tooele
19 County's nonattainment designation to include only areas above 5,600 feet in elevation. The
20 primary focus of the 1981 SIP for Salt Lake and Tooele counties, supported by both the State and
21 the EPA, was to control emissions from Kennecott's operations.

22
23 On August 17, 1981, the Governor submitted a revision to the SIP to address the attainment of
24 the SO₂ NAAQS in Salt Lake County and Tooele County. Additional supporting documents
25 were submitted by the State on December 7, 1981, and January 25, 1983. The primary control
26 measure in the SIP for Salt Lake and Tooele counties was the construction of a new smelter at
27 Kennecott to replace the old reverberatory furnace system. The only control measure in the SIP
28 for Cedar City was enforcement of the existing limitation for sulfur content in fuel oil used at
29 Southern Utah State College. In December of 1983, Cedar City was redesignated as an
30 attainment area for SO₂.⁴

² Utah SO₂, Salt Lake and Tooele counties and Cedar City do not meet primary and secondary SO₂ standards,
https://archives.federalregister.gov/issue_slice/1978/3/3/8907-9023.pdf#page=58, See Page 9039.

³ Utah State Implementation Plan, August 16, 1981, Section 9, Part B, Figure 9.B.1.

⁴ Utah Air Conservation Rule R307-1-4.2.

1 On February 7, 1983, the Governor formally requested that the SLC NAA and TC NAA be
2 redesignated to attainment. However, on March 23, 1984, the EPA proposed to postpone any
3 action on the redesignation request until several outstanding issues were resolved.⁵

4 ii) Control Strategies for Nonattainment Area

5 A careful review of the emissions inventory and diffusion modeling that was coordinated by the
6 State indicated that the emissions from one point source, Kennecott Copper Corporation, resulted
7 in violations of the 1971 NAAQS for SO₂ which were observed in both counties.

8
9 Ambient measurements taken by the Department of Health in Salt Lake County indicated that the
10 NAAQS were violated only at the site in Magna, Utah. Based on this information, the Magna
11 monitoring site was used as the control point for development of the control plan. No violations
12 of the 1971 NAAQS have been observed at any of the monitoring stations since 1980. As part of
13 the 1981 SIP,⁶ the State adopted revised emission limitations and control requirements for the
14 following Kennecott operations:

- 15 • Smelter Main Stack;
- 16 • Fugitive Emissions;
- 17 • Power Plant Boilers;
- 18 • Molybdenite Heat Treaters; and
- 19 • Refinery.

20 The power plant boilers, heat treaters, and refinery were required to meet constant emission
21 limitations. The fugitive emissions were controlled by application of “best engineering
22 techniques.”

23 The main stack, which accounted for 88% of the total emissions, was controlled by a variable
24 emission limitation. The main stack limits contained the following key elements:

- 25 • annual average emission limit of 18,200 pounds per hour (lbs/hr);
- 26 • cumulative occurrence limits at specified frequencies and 3-hour running average
27 emission rates; and
- 28 • a maximum 3-hour emission limit of 98,400 lbs/hr never to be exceeded.

29 These emission limitations were developed using the multipoint rollback (MPR) approach and
30 represented a 10% reduction from the allowable emissions under the previous state regulation. A
31 federally promulgated regulation specific to Kennecott had established a 6,030 lbs/hr emission
32 limit for the main stack and required the implementation of reasonably achievable control

⁵ Approval and Promulgation of State Implementation Plans Designation of Areas for Air Quality Planning Purposes, Utah Sulfur Dioxide Plan, March 23, 1984, 49 FR 10946.

⁶ Utah SO₂ SIP, <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=612086&dbid=0>.

1 technology (RACT) for fugitive emissions.⁷ However, in response to petitions for
2 reconsideration and legal challenges to that regulation, the EPA agreed in 1977 not to enforce
3 these limits.

4 iii) State Attainment Demonstration

5 The 1981 SO₂ SIP demonstration only addressed the attainment of NAAQS in the lower
6 elevations and did not address the elevated terrain. Instead, the State took the position that these
7 higher elevation areas did not constitute “ambient air” under the definition provided in 40 CFR
8 50.1(e), as they are not accessible to the general public.⁸

9
10 The State employed several methods in developing the proposed emission limitations and in
11 demonstrating that the SIP would provide a reasonable probability of attaining the NAAQS in
12 lower elevation areas. These methods included:

- 13 • analysis of measured violations in Magna, Utah, and at the Great Salt Lake Beach,
14 including identification of the causes of those violations;
- 15 • calibrated dispersion modeling estimates to predict SO₂ concentrations in the lower
16 elevations before and after implementation of the SIP;
- 17 • qualitative analysis of the impacts of fugitive emissions at the Great Salt Lake Beach and
18 the improvements expected as a result of the SIP; and
- 19 • MPR for the development of the variable emission limitations at the main stack.

20 EPA's Review of State Attainment Demonstration

21 (1) Elevated Terrain

22 Historically, the EPA has applied the regulatory definition of “ambient air” in such a way that if
23 public access were precluded such as by a fence or other physical barrier, then air over property
24 owned or controlled by a source is not considered “ambient air” and therefore not subject to
25 NAAQS. This policy is reflected in the November 26, 1975, EPA rulemaking affecting the
26 Kennecott main stack emission limits.⁹ The EPA proposed that documentation and representation
27 made by Kennecott adequately demonstrate that the company had taken reasonable and effective
28 precautions to limit general public access to company property, and thus the company property
29 in the elevated terrain is not “ambient air.” Public comments on EPA’s final rulemaking were
30 pending and under review.

⁷ Standards of Performance for Primary Copper Smelters, 42 FR 37937, July 25, 1977, and 40 CFR 60.160.
www.govinfo.gov/content/pkg/FR-1977-07-25/pdf/FR-1977-07-25.pdf.

⁸ Definitions: 40 CFR 50.1(e), [www.ecfr.gov/current/title-40/part-50/section-50.1#p-50.1\(e\)](http://www.ecfr.gov/current/title-40/part-50/section-50.1#p-50.1(e)).

⁹ Rules and Regulations 40 FR 54788, www.govinfo.gov/content/pkg/FR-1975-11-26/pdf/FR-1975-11-26.pdf.

(2) SO₂ Control Strategy for Main Stack

The strategy developed by the State for the main stack was derived from a general approach known as MPR. The MPR approach is designed to accommodate the highly variable SO₂ emissions produced by smelters and produces a cumulative frequency distribution of allowed emission rates. Emission limits are developed by cumulative distribution of observed emission rates and air quality measurements over an extended period of time, usually a year or more. The SIP includes specific emission limitations for the low-level sources as well as a multipoint limit for the main stack. The mission limits included in the 1981 SO₂ SIP were:

Table 1: 1981 SO₂ SIP Limits

Source	Emission Limit
Power Plant Boilers	0.48 lbs/MMBtu
Molybdenite Heat Treaters	139 lbs/hr
Refinery	117 lbs/hr
Fugitive Emissions	RACT
Main Stack - Annual Average	18,200 lbs/hr
Main Stack - 3 Hour Maximum	98,400 lbs/hr

In the State's attainment demonstration, the design value (DV) for the MPR was a calculated 3-hour concentration of 0.46 ppm in lower elevations as compared to the 1971 NAAQS of 0.50 ppm. As the DV is less than the standard, this allowed an 8.7% increase in allowable emissions from the base period. The result was an allowable annual average stack emission rate calculated to be 18,200 lbs/hr.¹⁰ During the technical review of the control strategy, the EPA identified the following technical deficiencies and enforcement issues:

To develop the MPR, the State used a supplemental control system (SCS) during the period of record, which violates the basic principle of the MPR equation that emissions and dispersion are independent. At this time, no other acceptable alternate data was available to develop emission limits for the Kennecott smelter.

- In DV selection, the State used the second highest of the discrete 3-hour average instead of the highest one-per-year maximum concentrations.
- The State-proposed regulations required continuous emission monitors (CEM) to operate at least 95% of the time in each one-month period. However, the regulation did not limit the duration of a single breakdown.¹¹

¹⁰ Utah State Implementation Plan, Section 9 Part B.3.c., Development of the 3-hour Tall Stack Emission Limit, May 15, 1992.

¹¹ Utah State Implementation Plan, Section 4.3.2., Regulation for Control of Main Stack SO₂ Emissions (Kennecott Mineral Company), August 16, 1981.

- The State-proposed regulations did not outline the procedure to follow when determining which CEM data is 20% or more in error. The regulation also gave the smelter the option to delete or retain such data.¹²

The EPA conducted additional analysis on the development of MPR and the selection of DV and concluded that the strategy for the Kennecott main stack should not jeopardize attainment and maintenance of the SO₂ NAAQS in the lower elevations.¹³

Per the enforcement issues, the EPA proposed revisions of the rules to include provisions both limiting individual monitor downtime and providing incentives to strive for 100% CEM data recovery. Additionally, the EPA proposed to incorporate 40 CFR Part 60, Appendix B Part 2 of the quality assurance requirements.¹⁴ The SIP was conditionally approved given the above-mentioned issues were addressed prior to final rulemaking. At this stage, public comments on EPA's final rulemaking were still under review.

(3) Low-Level Source Issues

During the winter of 1979 and 1980, there were five measured violations of the 24-hour standard of 0.14 ppm in Magna. In addition, during the winter of 1981 there were two measured violations of the same standard at the Beach monitor located near the smelter. The highest concentration at the site was 0.19 ppm. As a result of these observed violations, the State's control strategy was to demonstrate attainment at these receptors. Several studies conducted in the area attributed the violations to low-level fixed stack sources and fugitive emissions. The low-level emissions inventory for the non-fugitive sources from this time period are shown below:

Table 2: Emissions inventory of non-fugitive sources

Source	Emissions (lbs/hr)	
	1979	1983
Magna Heat Treater	454	136
Arthur Heat Treater	454	136
Refinery	354	103
Boiler	714	828
Boilers	375	401
Total	2,351	1,604

¹² Utah State Implementation Plan, Section 4.3.2., Regulation for Control of Main Stack SO₂ Emissions (Kennecott Mineral Company), August 16, 1981.

¹³ Approval and Promulgation of State Implementation Plans, 40 CFR Part 52 and 40 CFR Part 81.

¹⁴ Approval and Promulgation of State Implementation Plans, 40 CFR Part 52 and 40 CFR Part 81.

1 The State required a 70% emission reduction from the smelter's low-level sources and required
2 improved fugitive emission capture practices at the smelter. The effectiveness of the control
3 strategy was demonstrated via modeling efforts by the State. The modeling estimate predicted
4 attainment of the SO₂ standards by December 1982. EPA conducted an independent modeling
5 effort to verify the State's findings and determined that the results agreed with the State's result
6 at Magna, but the Beach monitor showed some variability.

7
8 Since the fugitive emissions and the reduction expected by December 1982 could not be reliably
9 quantified, the State submitted information on January 25, 1983, which described the control
10 practices on fugitive emissions implemented at the smelter since the 1981 violations and
11 included a qualitative analysis of the expected effects of those practices. The State's conclusions
12 regarding attainment of the standards in the vicinity have been substantiated by measured data
13 since 1981. Based on this information, the EPA ruled in favor of the State's control strategy for
14 the low-level sources to attain and maintain the SO₂ standards in lower elevations.

15 (4) Stack Height Credit

16 Under the 1982 stack height regulations,¹⁵ stack height credit can be calculated in the following
17 three methods¹⁶: (1) de minimis height (stack less than 65 meters); (2) mathematical formulas; or
18 (3) physical demonstrations. The State calculated its GEP stack height according to a fluid
19 modeling demonstration. The demonstration did not fully comply with EPA's 1982 regulations¹⁷
20 because no specific percentage of increased concentrations was measured. However, based on
21 the best engineering judgment of EPA technical staff, the source apparently could demonstrate at
22 least a 40% increase in concentrations using the approach in the 1982 regulations. Due to the
23 GEP regulation being under litigation and its uncertain status¹⁸, EPA concluded that it would be
24 futile to require the source to perform additional fluid modeling demonstrations based on the
25 1982 regulations.

26 iv) 1985 Interim SO₂ SIP Approval

27 On February 20, 1985, EPA proposed interim approval of the 1981 SIP on the condition that the
28 State of Utah agreed to satisfy all procedural and substantive requirements of the stack height
29 regulations once any further regulations were promulgated or the existing regulations were

¹⁵ Stack height Regulations, February 8, 1982, 47 FR 5864, www.govinfo.gov/content/pkg/FR-1982-02-08/pdf/FR-1982-02-08.pdf.

¹⁶ Method of Determining GEP Stack Height, February 8, 1982, 47 FR 5865, www.govinfo.gov/content/pkg/FR-1982-02-08/pdf/FR-1982-02-08.pdf.

¹⁷ Stack height Regulations, February 8, 1982, 47 FR 5864, www.govinfo.gov/content/pkg/FR-1982-02-08/pdf/FR-1982-02-08.pdf.

¹⁸ Sierra Club vs. EPA, 719 F.2d 436, www.casemine.com/judgement/us/5914c378add7b049347c6b6f.

upheld on appeal.¹⁹ For the final approval of the SIP, the State was required to promulgate additional SIP provisions committing to the following actions:

- In the event EPA promulgates new regulations with requirements different from those in the 1982 regulations, the State of Utah will, within nine months of such promulgation, submit a demonstration of the GEP stack height under the new regulations and, based on that demonstration, submit either: (a) a demonstration that the SIP adequately assures attainment when that height is taken into account; or (b) a SIP revision demonstrating attainment.
- In the event the 1982 regulations are upheld on appeal, the State will submit a new fluid modeling study meeting the requirements of those regulations within nine months of the decision.

v) 1986 GEP Stack Height SIP Submittal

The Utah GEP Stack Height SIP was submitted by the Governor in a letter dated May 2, 1986.²⁰ The submittal included regulations to address:

- GEP stack height credit and dispersion techniques;
- a new Section 17 of the SIP that listed all existing stacks in Utah greater than 65 meters; and
- a technical support document for Section 17 including the Kennecott Magna stack analysis.

The Kennecott stack height credit was a significant component of the Utah SO₂ SIP emission limits conditionally approved on February 20, 1985.

vi) Applicability of the NSPS Regulation

The federal New Source Performance Standards (NSPS) regulation for primary copper smelters (40 CFR 60 NSPS Subpart P) applies to any such facility that commences construction or modification after October 16, 1974.^{21, 22} Modification generally means any physical or operational changes which results in an increase in the emission rate to the atmosphere.

The Kennecott smelter expansion/modification began in the early 1970's, with a commitment to the 1,215-foot stack in 1973 and completion of the project in 1977. The acid plant system resulted in an increase from 60% sulfur capture to 86%, reducing sulfur emissions by

¹⁹ Approval and Promulgation of State Implementation Plans – Utah SO₂ Plan, February 20, 1985, 50 FR 7059, www.govinfo.gov/content/pkg/FR-1985-02-20/pdf/FR-1985-02-20.pdf.

²⁰ Utah SIP, Section XVIII, Demonstration of GEP Stack Height, May 2, 1986.

²¹ Standards of performance for Primary Copper Smelters, 42 FR 37937, July 25, 1977; www.govinfo.gov/content/pkg/FR-1977-07-25/pdf/FR-1977-07-25.pdf.

²² Applicability and designation of affected facility, 40 CFR 60.160, www.ecfr.gov/current/title-40/section-60.160.

1 approximately 65%. Based on this information, the EPA concluded that the 1970's Kennecott
2 expansion/modification did not subject the smelter to 40 CFR 60 NSPS Subpart P requirements.

3 vii) Analyses of the Stack Height SIP Submittal

4 The Kennecott stack height analyses were undertaken to comply with the July 8, 1985, stack
5 height regulations, as well as the conditions specified in the approval of the Utah SO₂ SIP.²³
6 Kennecott originally had two 400-foot stacks (grandfathered stack height) from which SO₂
7 emissions from the smelter were vented. The 1970's expansion/modification included the
8 replacement of the two 400-foot stacks with a single 1,215-foot stack. The GEP formula height
9 ($H + 1.5 L$), considering the nearby buildings, is 212.5-foot.

10
11 The initial Kennecott GEP demonstration was submitted on May 2, 1986, with subsequent
12 submittals on October 6, 1986, December 3, 1986, November 13, 1987, and May 11, 1988.

13 There were two basic parts to the Kennecott analysis:

- 14 • The GEP demonstration – which consisted of three subparts: a fluid modeling protocol,
15 the fluid modeling results, and an evaluation of the fluid modeling results with respect to
16 the stack height regulations.
- 17 • A Best Available Retrofit Technology (BART) analysis – performed if the source
18 contended that the NSPS emission limits were infeasible. Relevant factors for this
19 analysis include high cost-effectiveness ratio, excessive local community impact,
20 excessive plant impact, and infeasibility issues. Kennecott provided responses to all the
21 BART factors mentioned above. The cost effectiveness ratio and technical infeasibility
22 issues, however, were determined critical to this review because of their relationship to
23 the emission limitations used in the GEP analyses.

24 Because the Kennecott emissions, as established through MPR, were used in the 1981 SO₂ SIP,
25 EPA's primary concern with the use of any emission rate in the demonstration of GEP was
26 ensuring protection of the NAAQS. The basic concept behind GEP is to prevent sources from
27 using illegal dispersion techniques to avoid emissions controls.

28
29 Kennecott provided extensive data on its GEP analyses.²⁴ To summarize, the GEP demonstration
30 showed that the existing stack height of 1,215 feet met the 40% criterion due to terrain effects
31 and an exceedance of the NAAQS at MPR emission rates. MPR is a technique designed for
32 sources with variable emission rates (e.g., smelters). MPR allows for a frequency distribution of
33 emission rates which will permit extremely high emissions on rare occasions. The MPR
34 methodology was constructed around the recognition that any control strategy would have a

²³ Approval and Promulgation of State Implementation Plans – Utah SO₂ Plan, February 20, 1985, 50 FR 7059,
www.govinfo.gov/content/pkg/FR-1985-02-20/pdf/FR-1985-02-20.pdf.

²⁴ GEP Demonstration and BART Analysis, 53 FR 48942.

1 predictable probability of allowing a violation of the NAAQS. The MPR was based upon
2 allowing a 26% probability of recording a violation. The GEP demonstration satisfies the
3 excessive concentration criteria in EPA's regulation if MPR reflects the proper emission rates.
4 After review, EPA concluded that Kennecott's analyses were acceptable, since Kennecott
5 performed a fluid modeling study consistent with existing guidance and the study was approved
6 by EPA.

7
8 Application of the level of control required by NSPS would reduce the emissions of SO₂ at
9 Kennecott during the stable process phase, but would not affect emission rates under startup,
10 shutdown, malfunction, and upset conditions. This is because the NSPS emission rate is for
11 normal operations and excludes such process conditions. MPR includes startup, shutdown,
12 malfunction, and upset conditions. From the Kennecott assessment, considering only long-term
13 averages, the cost portion is consistent with the tons of SO₂ reduction expected from similar
14 NSPS applications. In the Kennecott BART analysis, the controlling emissions for the
15 determination of GEP appeared to be those under upset, start-up, shutdown, and malfunction
16 conditions. Therefore, while there would be no difference in the emission rates under these
17 conditions as a result of meeting NSPS, there would be a substantial additional cost to control
18 these emissions.

19
20 In summary, the emissions at the smelter from startups, shutdowns, upsets, and malfunctions
21 were included in the MPR emission limits and would be considered in the NAAQS attainment
22 and GEP analyses. Application of NSPS technology would not affect these emission rates and
23 would, therefore, result in no change in demonstrating GEP. It may be possible to reduce annual
24 emissions by requiring additional controls on the smelter, but such reduction would have no
25 relevance to the limiting case for determination of GEP.

26
27 Given the above discussion, EPA proposed to approve²⁵ the Kennecott analysis in the Utah GEP
28 SIP submitted on May 2, 1986, with subsequent submittals on October 6, 1986, December 3,
29 1986, November 13, 1987, and May 17, 1988. However, EPA's review was conducted under a
30 specific assumption: that the emission rate(s) in the SO₂ SIP was sufficient to demonstrate
31 attainment. That assumption followed another critical assumption: that Kennecott owned or
32 controlled the lands in the upper elevation for which no monitoring data exists to demonstrate
33 attainment of the NAAQS.

34
35 Only one comment was received in response to the December 5, 1988, Federal Register which
36 proposed approval of the Kennecott GEP demonstration. The comment was from Kennecott in
37 support of this action. However, prior to publication of the proposed Federal Register approval,

²⁵ Approval and Promulgation of State Implementation Plans: Utah; Stack Height Analyses and Regulations, 53 FR 48942, December 5, 1988, www.govinfo.gov/content/pkg/FR-1988-12-05/pdf/FR-1988-12-05.pdf.

1 EPA received a letter from a landowner in the Oquirrh Mountains expressing concerns about the
2 lack of ambient monitoring in the nonattainment area. This was EPA's first documented
3 information on public access in the nonattainment area other than the Kennecott operation. EPA
4 proceeded to continue its evaluation of the State submittal and to publish its position on the GEP
5 demonstration based on the State submittal but initiated a reevaluation on land ownership above
6 the 5,600 feet elevation in the Oquirrh Mountains. Documentation on the claim of
7 landownership, other than that of the Kennecott operations, was provided by Howard Haynes,
8 Jr., in March 1989.²⁶

9 viii) 1981 SO₂ and 1986 GEP SIP Reassessment

10 Data from the Salt Lake County and Tooele County Assessor offices showed over 80 landowners
11 in the nonattainment area. Kennecott also conducted independent research and verified the list of
12 landowners. One of the critical assumptions of the conditional approval of the 1981 SO₂ SIP and
13 the emission rate was Kennecott's ownership or control of those lands in the potential
14 nonattainment area in the Oquirrh Mountains. The land ownership research revised the EPA's
15 earlier assumptions on the adequacy of the 1981 SO₂ and the 1986 GEP Stack SIPs.
16

17 In response, EPA began discussions with Kennecott and the State to resolve these issues and
18 outline a path forward for addressing the SO₂ and GEP SIPs. During these negotiations, the State
19 was also in the process of developing the PM₁₀ SIP for the Salt Lake County nonattainment area.
20 This process identified SO₂ as a key precursor to PM₁₀ pollution. Sulfates formed from SO₂
21 emissions are among the most common secondary particles contributing to PM₁₀ nonattainment.
22 Kennecott's smelter alone was responsible for 56% of the county's total PM₁₀ emissions,
23 including both primary and secondary particles.
24

25 The State adopted the PM₁₀ SIP in August 1991 and submitted it to the EPA in November of the
26 same year²⁷. The SIP imposed significant SO₂ emission reductions across Kennecott's operations
27 including the mine, concentrator, refinery, power plant, and smelter. The allowable smelter SO₂
28 emissions were reduced from 76,000 tons per year (tpy) or 18,000 lbs/hr annual average as set by
29 the 1981 SO₂ and 1986 GEP SIPs, to 18,500 tpy. This new limit included fugitive emissions and
30 applied to the entire smelter operation. The previous 76,000 tpy cap applied only to emissions
31 from smelter processing units and SO₂ removal systems vented through the 1,215-foot stack and
32 did not account for fugitive emissions. Under the revised PM₁₀ SIP, the stack-specific limit was

²⁶ Approval and Promulgation of State Implementation Plans: Utah; Stack Height Analyses and Regulations and SO₂ Nonattainment Plan, 59 FR 239, December 14, 1994, www.govinfo.gov/content/pkg/FR-1994-12-14/html/94-30607.htm.

²⁷ Approval and Promulgation of Air Quality Implementation Plan: Utah; Revision to the State Implementation Plan Addressing PM₁₀ for Salt Lake and Utah County, July 8, 1994, https://archives.federalregister.gov/issue_slice/1994/7/8/35035-35044.pdf.

lowered to 14,191 tpy, encompassing only emissions from the processing units and pollution control equipment.

ix) 1991 GEP and 1992 SO₂ SIP Submittals

On November 15, 1990, The CAA was amended to address issues like acid rain, urban air pollution, toxic air emissions, and stratospheric ozone depletion. The amendments also established a national operating permits program and strengthened enforcement provisions.²⁸ On May 15, 1992, the Governor of Utah submitted a revision to Section 9, Part B of the SO₂ SIP to address the amendment to the CAA requirement that a SIP revision be submitted by May 15, 1992, for any area that did not have a fully approved SIP as the 1981 SO₂ SIP was only conditionally approved. The significant changes in this SIP revision from that of the 1981 submittal were as follows:

- Revision to the GEP Stack height Section 16 set an allowable emissions limit of 14,191 tpy for the 1,215-foot main stack, as derived in the PM₁₀ SIP.²⁹ This limit reflects the use of double-contact acid plant technology, improved capture of fugitive emissions, and enhanced operation and maintenance.
- The MPR emission limitations and assumptions were removed and replaced with the emission limitation that can be achieved using the NSPS technology, double contact acid plant, or the equivalent of NSPS. NSPS is the presumptive norm for RACT for this facility. The SO₂ SIP was revised to reference the same emission limitations as those stated in the PM₁₀ SIP.
- The 1971 SO₂ NAAQS³⁰ are 0.14 ppm for the 24-hour primary standard, and 0.5 ppm for the 3-hour secondary standard. The 24-hour impact analysis was a rollback analysis that compared the smelter emissions in 1991 (PM₁₀ SIP emission limitation) with the 1979 emissions. The State had monitoring data showing attainment at Lake Point (an area originally defined as ambient air and owned by the Bureau of Land Management but now owned by Kennecott) where exceedances were recorded. The Lake Point site could be considered representative of the closest point in the elevated terrain that would be impacted by the tall stack emissions. Demonstrating attainment at Lake Point would technically support the attainment elsewhere in the elevated terrain that is considered ambient air. The area considered ambient air in the elevated terrain is a significant distance downwind from Lake Point.
- The PM₁₀ SIP emission limitation was based on a 24-hour SO₂ limit; this emission limitation was to be achieved through a given lbs/hr calculated on a 6-hour average. The 24-hour limit was considered “controlling” for PM₁₀ and SO₂ (i.e., the 24-hour limitation

²⁸ 1990 Clean Air Act Amendment, www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary.

²⁹ 1994 Revision to the State Implementation Plan Addressing PM₁₀ for Salt Lake and Utah County, https://archives.federalregister.gov/issue_slice/1994/7/8/35035-35044.pdf.

³⁰ Table of Historical SO₂ NAAQS, www3.epa.gov/ttn/naaqs/standards/so2/s_so2_history.html.

was believed to be the level of control necessary for PM₁₀ attainment, as well as for the SO₂ attainment demonstration). The SO₂ SIP established a 3-hour limitation and verified that such limitation would protect the 3-hour NAAQS.

- Section 4.2 of the Utah Air Conservation Rules was revised to include a 24-hour averaging period for the sulfur content of coal, fuel oil, and fuel mixtures, and to specify the ASTM methods to be used to demonstrate compliance with the limitation and reporting requirement. The previous rule specified a limit for the sulfur content of fuels but did not specify an averaging time or specific ASTM methods. Section 4.6 was also revised to include a 3-hour averaging time for Sulfur Burning Production Sulfuric Acid Plants.
- Specific regulations which were provided for special consideration (including malfunction provisions) on the smelter fluctuating operation were removed. Malfunction provisions for the Kennecott smelter operation were the same as for any stationary source in Utah. This issue was addressed during the PM₁₀ SIP development and was approved under the PM₁₀ SIP federal approval process. These regulation impacts were clarified in the SO₂ SIP revision.

x) 1994 SO₂ and GEP SIP Approval

On December 14, 1994, EPA approved the SO₂ and GEP stack height SIPs, as they were consistent with the EPA guidance.³¹ General SO₂ regulations that were previously determined as deficient with respect to meeting the statewide SO₂ SIP requirements were also approved.

EPA advised the State to ensure consistency with the State's permits and the federally enforceable SIP. The State's permit program was part of the federally approved SIP. The final approval of SO₂ and GEP stack height SIPs also made the emission limitations for these stationary sources federally enforceable. EPA advised the State that if different emission limitations exist, EPA will enforce the more stringent of the two or more emission limitations. This is to ensure that the attainment demonstration of a nonattainment area is maintained. It is therefore critical that the State maintain consistent emission limitations in permits and in federally approved SIPs and update the emission limitations sections of these plans to ensure clarity and consistency.

³¹ Approval and Promulgation of State Implementation Plans, Utah Stack Height Analyses and Regulations, December 14, 1994, 59 FR 18341, www.federalregister.gov/documents/search?conditions%5Bterm%5D=59+FR+18341.

xi) 1999 SO₂ Draft Maintenance Plan Submission

In November 1999, a draft SO₂ maintenance plan and redesignation request³² for Salt Lake and Tooele counties was submitted to the EPA for review. The draft reported that there had been no violations of the 1971 SO₂ NAAQS in the nonattainment area. It credited this to improvements made at the Kennecott smelter, which were sufficient to both achieve and maintain compliance with the standard.

The draft also noted that other major SO₂ sources in the nonattainment area were addressed through the PM₁₀ SIP, which reduced emissions to levels significantly lower than those in the 1980s. These SO₂ limits were federally enforceable, and no additional control measures were considered necessary to maintain the NAAQS.

In higher elevation areas, the Kennecott smelter was identified as the only potential source of concern. However, based on a rollback of earlier modeling data and a straight rollback analysis, the current emission limits in the SO₂ SIP for Kennecott are determined to be more than adequate to ensure continued compliance in those areas. The plan further stated that these limits will remain federally enforceable and are not expected to increase over the next decade.

xii) EPA Review of the 1999 Draft Maintenance Plan

The EPA reviewed the State's submission and identified several deficiencies in the maintenance plan in a letter dated December 17, 1999.³³ These deficiencies are summarized below:

- The letter emphasized the need for a thorough review of a historical, current, and future allowable emissions inventory for SO₂ sources in the nonattainment area to determine if further dispersion modeling is needed.
- A screening analysis was recommended to determine the need for further dispersion modeling. This involved reviewing emissions, performing screening modeling if future emissions were significant, and potentially more refined modeling if the screening modeling indicated violations.
- The letter included several comments on the enforceability of emission limits within the maintenance plan, stressing that limits must remain in effect, be federally enforceable, and be consistent with NAAQS timeframes. Specific comments were made regarding Kennecott's emission limits, stating the State must commit to current emission levels in place or analyze and project growth increase.
- The letter deemed the contingency measures outlined in the draft maintenance plan to be insufficient, as the draft lacked clear identification of potential measures, a schedule and

³² Draft SO₂ Maintenance Plan and Redesignation Request, November 1999.

³³ December 17, 1999, Letter from the EPA Region 8 in response to Utah's draft maintenance plan submission.

1 procedure for adoption and implementation, and a specific time limit for State action,
2 with a commitment to fully implement corrective measures within one year of a NAAQS
3 violation.

- 4 ● The EPA noted that the draft maintenance plan does not provide a projected maintenance
5 year which is a required minimum of 10 years from the approved maintenance plan. The
6 maintenance plan shall include attainment and maintenance year emissions inventories
7 and explain how maintenance will be ensured.
- 8 ● Additionally, the letter requested clarification regarding the operation and replacement of
9 SO₂ monitors at the Lakepoint site in 1992.

10 xiii) Developing Modeling Protocol

11 Since the EPA's review of the 1999 draft Maintenance Plan, the State has developed a modeling
12 protocol³⁴ to demonstrate attainment of the 1971 NAAQS in the nonattainment area. The
13 protocol outlined the procedures, assumptions, data, and models to be used by the State to predict
14 ambient SO₂ concentrations from five petroleum refineries in Salt Lake and Davis counties. The
15 modeling analysis was requested by the EPA as a supplement to Utah's earlier effort to
16 redesignate Salt Lake County and part of Tooele County to attainment.

17
18 The EPA found the technical aspects of the modeling protocol acceptable, including the use of
19 alternative models, overlapping modeling domains, nearby sources, urban/rural dispersion
20 coefficients, background concentrations (with a request for Kennecott's annual emissions for
21 documentation), meteorological data, and receptor locations³⁵. However, the modeling protocol
22 did not include specific information regarding emission points, such as emission rates, caps,
23 routine flare emissions, stack heights, and enforceable measures. The State agreed to address
24 these concerns in the Maintenance Plan and received conditional approval from the EPA for the
25 modeling protocol³⁶.

26 xiv) 2004 SO₂ Draft Maintenance Plan Submission

27 The State drafted a new SO₂ Maintenance Plan³⁷ for the Salt Lake County and Tooele County
28 nonattainment areas and submitted it to the EPA for review on August 20, 2004. The newly
29 drafted Plan stated that there had been no violation in the nonattainment area of any primary or
30 secondary NAAQS for SO₂ since 1981. This lack of monitored violations was attributed to the
31 permanent and enforceable emission reductions at the Kennecott main stack which led to the

³⁴ October 4, 2001, SO₂ Modeling Protocol, State submittal to the EPA.

³⁵ November 14, 2001, EPA Review of October 4, 2001 Modeling Protocol for Salt Lake County Sulfur Dioxide (SO₂) Redesignation Study, EPA letter to the State.

³⁶ November 14, 2001, EPA Review of October 4, 2001 Modeling Protocol for Salt Lake County Sulfur Dioxide (SO₂) Redesignation Study, EPA letter to the State.

³⁷ January 5, 2005, Sulfur Dioxide Maintenance Provisions for the Salt Lake-Tooele Sulfur Dioxide Nonattainment Area. Section IX.B.6.

area’s original nonattainment status. Based on this, the State requested redesignation of the nonattainment area. No modeling analysis was included in the draft Maintenance Plan in an effort to demonstrate attainment.

xv) EPA Review of the 2004 Draft Maintenance Plan

In a letter dated November 4, 2004, the EPA outlined their findings and comments for the draft Maintenance Plan.³⁸ The letter stated that based on the preliminary review of the draft, several fundamental requirements for maintenance plans and redesignations to attainment had not been satisfied. The draft also did not demonstrate maintenance, project a maintenance date, or contain sufficient contingency measures. On January 4, 2005, the EPA followed up in a letter recommending deferred action on the Maintenance Plan and redesignation request due to the significant unaddressed issues.³⁹ On April 19, 2005, the State formally submitted the SO₂ Maintenance Plan for Salt Lake County and parts of Tooele County.⁴⁰ The EPA never formally acted on the SO₂ Maintenance Plan. In a letter dated November 12, 2019, the State withdrew “UT SO₂ Redesignation and Maintenance Plan for Salt Lake City and UT SO₂ Redesignation and Maintenance Plan for parts of Tooele County,” both submitted on April 19, 2005⁴¹. The letter stated that “the Utah Division of Air Quality is working closely and cooperatively with the EPA to craft an approvable maintenance plan so EPA can act on it promptly following submission.”

IX.B.12.c Redesignation Requirements

Section 107(d)(3)(E) of the Act outlines five requirements that a nonattainment area must satisfy before an area may be eligible for redesignation from nonattainment to attainment. Table 3 identifies the redesignation requirements as they are stated in Section 107(d)(3)(E) of the Act. Each element will be addressed in turn, with the central element being the maintenance plan found in Subsection IX.B.12.d below.

³⁸ November 4, 2004, Sulfur Dioxide Maintenance Provisions, EPA letter to the State.

³⁹ January 4, 2005, Sulfur Dioxide Maintenance Provisions, EPA letter to the State.

⁴⁰ April 19, 2005, Sulfur Dioxide Maintenance Provisions for the Salt Lake-Tooele Sulfur Dioxide Nonattainment Area. Section IX.B.6, Governor’s letter to the EPA.

⁴¹ November 12, 2019, State of Utah withdrawing the maintenance plan, Governor’s letter to the EPA.

1 Table 3: Requirements to Redesignation in the Federal Clean Air Act

Category	Requirement	Reference	Addressed in Section
Attainment of Standard	Most recent two complete consecutive years of quality-assured monitoring data must show that violations of the standard are no longer occurring ⁴²	CAA §107(d)(3)(E)(i)	IX.B.12.c(i)
Approved SIP	The applicable implementation plan for the area must be fully approved	CAA §107(d)(3)(E)(ii)	IX.B.12.c(ii)
Permanent and Enforceable Reductions	The State must be able to reasonably attribute the improvement in air quality to emission reductions that are permanent and enforceable	CAA §107(d)(3)(E)(iii) Calcagni memo (Sec. 3, para 2) ⁴³	IX.B.12.c(iii)
Section 110 and Part D Requirements	The State must verify that the area has met all requirements applicable to the area under Section 110 and Part D	CAA: §107(d)(3)(E)(v), §110(a)(2), Sec 171	IX.B.12.c(iv)
Maintenance Plan	The Administrator has fully approved the Maintenance Plan for the area as meeting the requirements of CAA §175A	CAA §107(d)(3)(E)(iv)	IX.B.12.c(v) and IX.B.12.d

2 i. The Area Has Attained the 1971 SO₂ NAAQS

3 *CAA 107(d)(3)(E)(i) - The Administrator determines that the area has attained the national*
4 *ambient air quality standard.* To satisfy this requirement, the State must show that the area is
5 attaining the applicable NAAQS. According to EPA's guidance⁴⁴ concerning area
6 redesignations, there are generally two components involved in making this demonstration: (1)
7 relies upon ambient air quality data which should be representative of the area of highest
8 concentration and should be collected and quality assured in accordance with 40 CFR 58; and
9 (2) relies upon supplement air quality modeling. Each component will be addressed in turn.

⁴² Memorandum From Sheldon Myers, Director, EPA Office of Air Quality Planning and Standards to Regional Office Air Division Directors, "Section 107 Designation Policy Summary" April 21, 1983, <https://www.federalregister.gov/d/2014-09458/p-92>.

⁴³ John Calcagni, September 4, 1992, EPA Memorandum "Procedure for Processing Requests to redesignate Areas to Attainment" https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf.

⁴⁴ John Calcagni, September 4, 1992, EPA Memorandum "Procedure for Processing Requests to Designate Areas to Attainment" https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf.

(1) Ambient Air Quality Data (Monitoring) and Utah's Monitoring Network

The NAAQS for the 1971 SO₂ standard are as follows⁴⁵: primary standards include an annual (calendar year) arithmetic mean of 0.03 ppm and a 24-hour midnight to midnight block average of 0.14 ppm. An exceedance of the annual standard is a violation of the NAAQS, as are two exceedances of the 24-hour standard in any one calendar year at any one monitor site. In addition, there is a secondary standard of 0.5 ppm measured as a 3-hour block average, calculated from successive non-overlapping 3-hour blocks starting at midnight. Two exceedances of the 3-hour standard in a calendar year at any one monitoring site is a violation of the NAAQS. In order to demonstrate attainment of these standards, the State must collect eight consecutive calendar quarters (two years) of ambient data that is below the levels outlined above.⁴⁶ It is important to note that although the current SO₂ standards^{47, 48} are significantly more stringent than those established in 1971, they are being met with a substantial margin of compliance.

The Division's Air Monitoring section maintains an ambient air monitoring network in Utah in accordance with 40 CFR 58 that collects both air quality and meteorological data. Figure 1 shows the location of both historical and present SO₂ monitoring sites in the state. The data collected at these sites are routinely audited by the EPA and meets the agency's requirements for air monitoring networks.

⁴⁵ 40 CFR 50.4, National primary ambient air quality standards for sulfur oxides (sulfur dioxide), <https://www.ecfr.gov/current/title-40/section-50.4>.

⁴⁶ Memorandum From Sheldon Myers, Director, EPA Office of Air Quality Planning and Standards, to Regional Office Air Division Directors, "Section 107 Designation Policy Summary" April 21, 1983.

⁴⁷ 40 CFR 50, Review of the Primary National Ambient Air Quality Standards for Sulfur Oxides, www.federalregister.gov/documents/2019/03/18/2019-03855/review-of-the-primary-national-ambient-air-quality-standards-for-sulfur-oxides.

⁴⁸ 40 CFR 50, Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen, Oxides of Sulfur, and Particulate Matter, www.govinfo.gov/content/pkg/FR-2024-12-27/pdf/2024-29463.pdf.

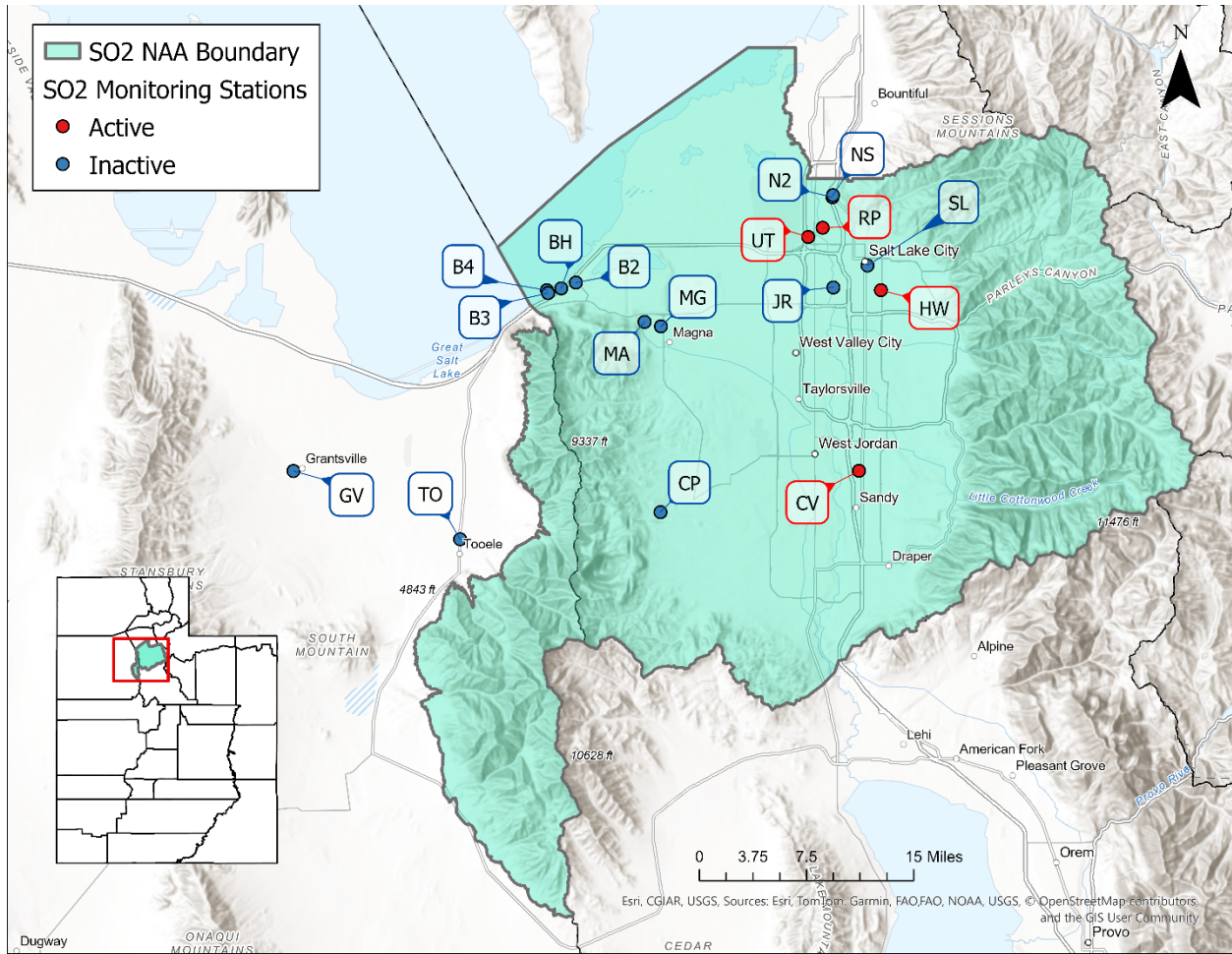


Figure 1: SO₂ nonattainment area boundary and monitoring network

Table 4 shows the SO₂ monitor values from 1981 to 2024. The data was downloaded from EPA's Air Quality System (AQS) database. Monitors that did not have three consecutive years of data available were excluded from this table. As shown in Table 4, a violation of the 24-hour standard was recorded at two monitors in 1981. Since then, there has been no recorded violation of the 1971 SO₂ standards in the nonattainment area.

1 Table 4: Nonattainment area monitoring data from 1981 – 2024

Year	AQS Site Number	1 st 24-hr Max (ppm)	Mean Annual Standard* (ppm)	3-hr Arithmetic Mean* (ppm)
1971 SO₂ Standards		0.14	0.03	0.5
1981	TO, MG, BH, SL, CP	0.160	0.034	0.034
1982	NS, JR, MG, BH, SL, CP	0.086	0.025	0.026
1983	JR, MG, BH, SL, CP	0.113	0.015	0.015
1984	N2, MG, SL, CP	0.080	0.013	0.013
1985	N2, MG, SL, CP	0.080	0.013	0.013
1986	B2, N2, MG, SL, CP	0.096	0.013	0.013
1987	B2, N2, MG, SL	0.109	0.027	0.028
1988	B2, N2, MG, SL	0.112	0.022	0.022
1989	B2, N2, MG, SL	0.111	0.019	0.019
1990	B2, N2, MG, SL	0.089	0.018	0.019
1991	B2, N2, MG, B3, SL	0.079	0.014	0.140
1992	N2, MG, B3, B4, SL	0.129	0.015	0.015
1993	N2, MG, B4, SL, GV	0.067	0.013	0.013
1994	N2, MG, B4, SL, GV	0.046	0.011	0.011
1995	N2, MG, B4, GV	0.066	0.004	0.004
1996	N2, MG, B4, GV	0.022	0.004	0.004
1997	N2, MG, B4, GV	0.019	0.004	0.004
1998	N2, MG, B4	0.029	0.003	0.003
1999	N2, MG, B4	0.012	0.004	0.004
2000	N2, MG, B4	0.014	0.004	0.004
2001	N2, MG, B4	0.013	0.004	0.004
2002	N2, MG, B4	0.010	0.004	0.004
2003	N2, MG, B4	0.015	0.005	0.005
2004	N2, MG, B4	0.015	0.004	0.004
2005	N2, MG, B4	0.011	0.003	0.003
2006	N2, MG, B4	0.008	0.003	0.003
2007	N2, MG, B4	0.011	0.003	0.003
2008	N2, MG, B4	0.009	0.003	0.003
2009	N2, MG, B4	0.018	0.004	0.004
2010	N2, MG, B4, HW	0.012	0.004	0.004
2011	N2, MG, B4, HW	0.007	0.002	0.002
2012	N2, MG, B4, HW	0.008	0.003	0.003
2013	N2, MG, B4, HW	0.006	0.003	0.003
2014	HW	0.002	0.001	0.000

Year	AQS Site Number	1 st 24-hr Max (ppm)	Mean Annual Standard* (ppm)	3-hr Arithmetic Mean* (ppm)
2015	HW	0.004	0.000	0.000
2016	HW	0.002	0.001	0.001
2017	HW	0.002	0.000	0.000
2018	CV, HW, RP	0.002	0.001	0.001
2019	MA, CV, HW, RP, UT	0.005	0.001	0.001
2020	CV, HW, RP, UT	0.002	0.000	0.000
2021	CV, HW, RP, UT	0.003	0.001	0.001
2022	CV, HW, RP, UT	0.003	0.001	0.001
2023	CV, HW, RP, UT	0.003	0.001	0.001
2024	CV, HW, RP, UT	0.002	0.001	0.001

TO: 49-045-0001; MG: 49-035-1001; BH: 49-035-2002; SL: 49-035-3001; CP: 49-035-4001; N2: 49-035-0012; B2: 49-035-0005; B4: 49-035-2004; HW: 49-035-3006; CV: 49-035-2005; RP: 49-035-3010; UT: 49-035-3015; NS: 49-035-0007; JR: 49-035-0009; B3: 49-035-2003; GV: 49-045-0002; MA: 49-035-1007

*Monitoring data was obtained from the AQS database on August 13, 2025. Discrepancies may be present due to historical recordkeeping practices and rounding errors.

The time series plots presented below illustrate the monitored SO₂ concentration from 1981 to 2024 in the nonattainment area. The plots show a clear and consistent downward trend in monitored SO₂ concentrations over the 43-year period. This decline is evident for both the primary and secondary SO₂ standards, indicating improvements in air quality that benefit both public health (primary standard) and environmental welfare (secondary standard). In the plots, the applicable SO₂ standard is represented by a dotted line, providing a visual reference point for assessing compliance over time, suggesting a positive trajectory toward air quality improvement.

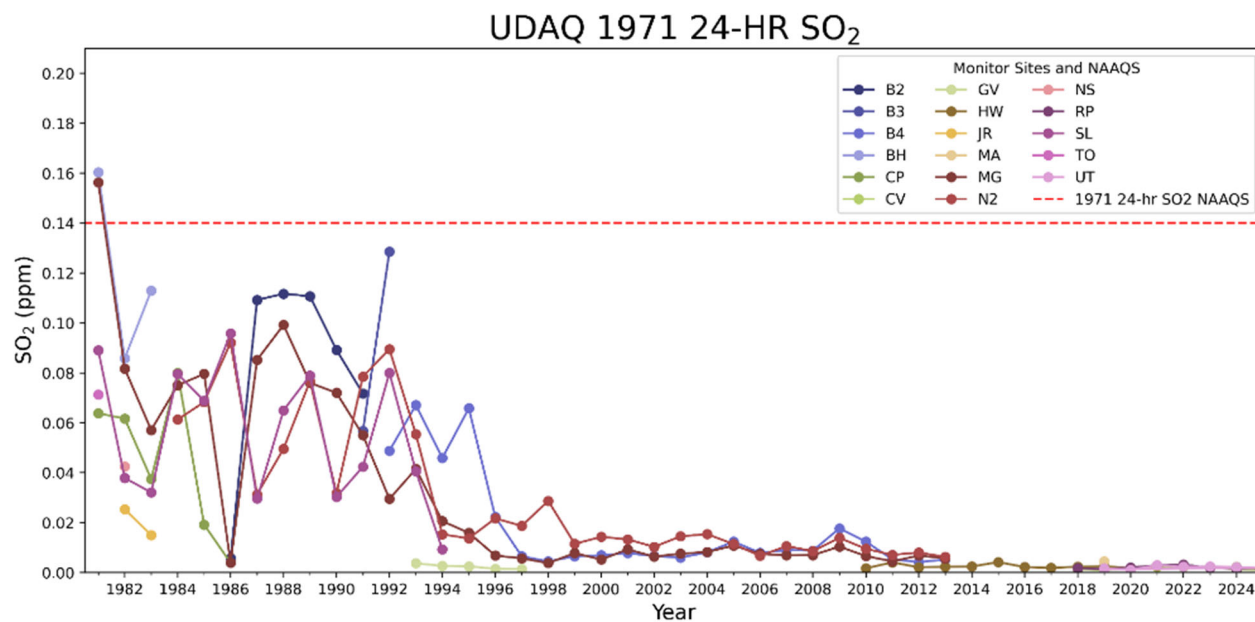


Figure 2: Monitored SO₂ values compared with 1971 24-Hour SO₂ standard

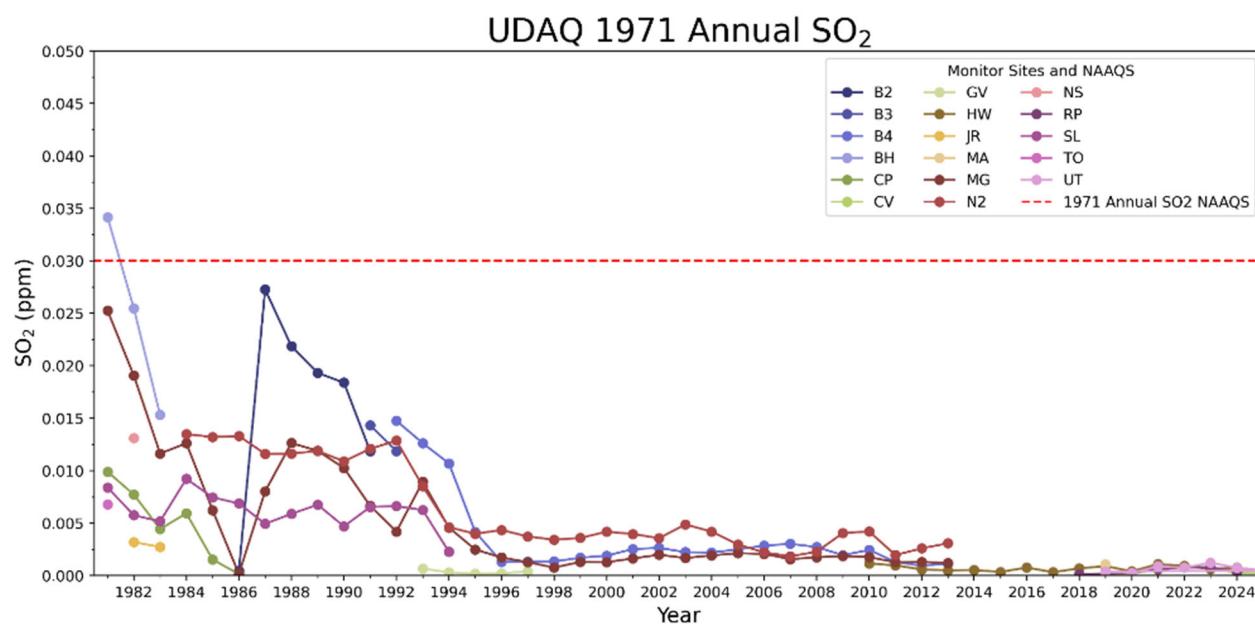


Figure 3: Monitored SO₂ values compared with 1971 Annual SO₂ standard

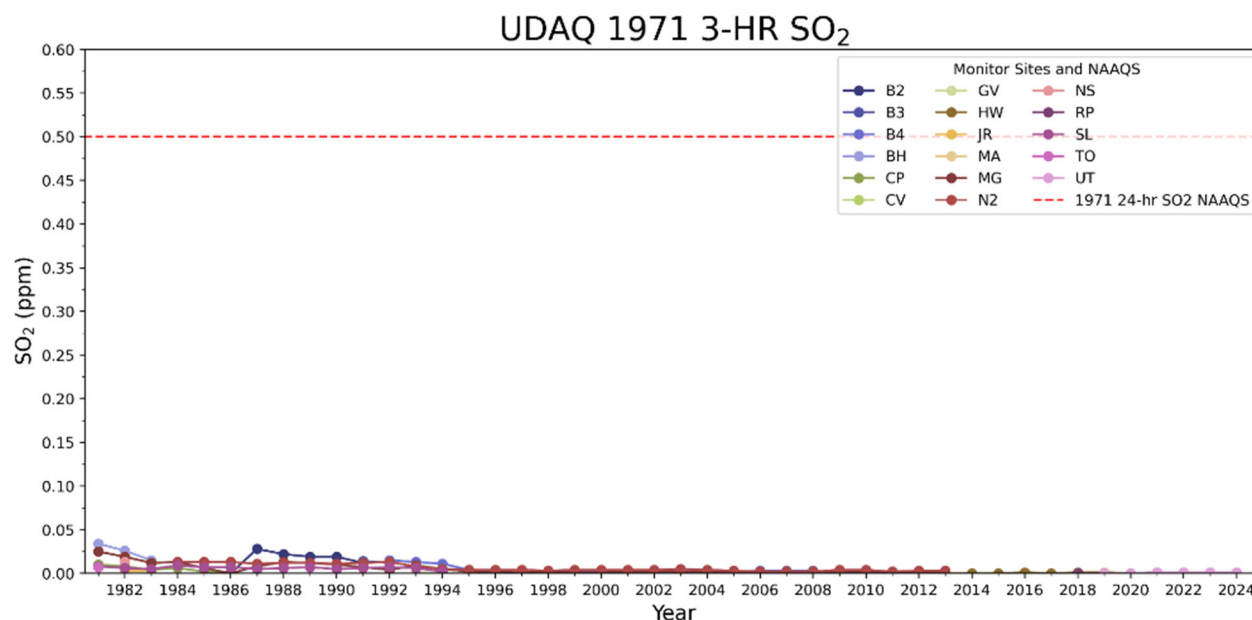


Figure 4: Monitored SO₂ values compared with 1971 3-hour SO₂ standard

(2) Modeling Element

EPA guidance⁴⁹ concerning redesignation requests and maintenance plans discusses the requirement that the area has attained the standard and notes that air quality modeling may be necessary to determine the representativeness of the monitored data. Areas that were designated nonattainment based on modeling will generally not be redesignated to attainment unless an acceptable modeling analysis indicates attainment. Dispersion modeling was conducted for the purpose of this maintenance demonstration to show compliance with the 1971 SO₂ NAAQS. Findings of the modeling analysis are summarized and discussed below. A detailed report of the modeling effort can be found in Appendix 1.

A. Introduction

The modeling effort was supported by Ramboll for use in the attainment demonstration. The model was run for all three 1971 standards. The modeling platform developed for this purpose incorporated a detailed modeling protocol, input from the Division and EPA Region 8 through a series of meetings, emissions data and stack characteristics for permitted sources provided by the Division, as well as relevant federal guidance on state implementation plan modeling, including the use of the AERMOD modeling system in accordance with 40 CFR Part 51, Appendix W.

⁴⁹ John Calcagni, September 4, 1992, EPA Memorandum "Procedure for Processing Requests to Redesignate Areas to Attainment" https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf.

A base year emissions inventory was provided by the Division, consisting of potential emissions and actual emissions for the most recent available year (2023) for sources in the airshed. The modeling demonstration includes consideration of a representative background concentration and the explicitly modeled impacts of six facilities in or near the nonattainment area. To maintain a conservative approach, the facilities were modeled based on their facility-wide allowable emission limits, which exceed the actual emissions by a considerable margin. These identified six facilities are:

- Kennecott Smelter and Refinery;
- Gadsby Power Plant;
- Tesoro Refinery;
- Chevron Refinery;
- Big West Refinery; and
- HF Sinclair Refinery.

The complete list of sources, site potentials to emit, and 2023 actual emissions for facilities in the nonattainment area and surrounding area are provided in Appendix 1.

Table 5: 1971 SO₂ Standards

Period	Standard	Value (ppm)	Value (µg/m ³)	Form	SIL* (µg/m ³)
3-Hour	Secondary	0.5	1,300	Not to be exceeded more than once per year (Highest Second High)	25
24-Hour	Primary	0.14	365	Not to be exceeded more than once per year (Highest Second High)	5
Annual	Primary	0.030	80	Annual mean; Not to be exceeded	1

*Significant Impact Level

Table 6: Background Design Value (DV)

Period	DV (ppb)	DV (µg/m ³)*
3-Hour	4.5	11.79
24-Hour	2.8	7.34
Annual	1.22	3.20

*Using the EPA conversion rate of 1 ppb SO₂ = 2.62 (µg/m³) SO₂

To aid in the modeling interpretation, three runs were performed for each standard:

- A “combined” run where effects of all emissions units are modeled at all receptors (including the effects of Kennecott emissions on its own property). This inclusion of on-

property impacts of emissions is a simple and conservative first run, designed to identify areas of refinement if needed, since not all modeled impacts using this approach can be compared to the NAAQS.

- A “Kennecott zero out” run where the emission rates of Kennecott emission units are set to zero. These runs may be used to evaluate NAAQS compliance at receptors inside the Kennecott fenceline.
- An “outside Kennecott” run where the receptors inside the Kennecott fenceline are excluded. These runs may be used to evaluate NAAQS compliance at all locations to which the public has access (i.e., not owned and controlled by Kennecott).

Note that the procedures regarding evaluation of ambient air for Kennecott are equally valid for the other five explicitly modeled facilities as well (e.g., effects of emissions from Tesoro emission units are not considered when evaluating NAAQS compliance at receptors on land owned and controlled by Tesoro where public access is effectively precluded). However, since modeled concentrations in northern Salt Lake County were well under the NAAQS, even within facility boundaries, the refined treatment of ambient air was not performed for those facilities.

B. 3-Hour Results

The results of the 3-hour modeling are shown in Table 7. Figure 2 and Figure 3 illustrate the impacts of nonattainment area-wide, and in the immediate vicinity of Kennecott. The concentrations reported are the highest second-high concentrations in any year, in accordance with the form of the NAAQS. The total impacts are the sum of the modeled value and the background value and are compared to the NAAQS.

Table 7: Results of 3-Hour Modeling

Scenario	Year	Modeled Value (µg/m ³)	Background Value (µg/m ³)	Total Impact (µg/m ³)	NAAQS (µg/m ³)
Combined	2020	935.96	11.79	947.75	1,300
Kennecott zero out	2022	7.11	11.79	18.90	
Outside Kennecott	2020	244.28	11.79	256.07	

Total impacts at all receptors are below the NAAQS, even when conservatively including Kennecott’s own impact on its own property. Indeed, as seen in Figure 3, the receptor with the highest impact is at the main smelter and refinery building itself, which is not in ambient air. When the impacts of the other facilities and background are evaluated at the Kennecott receptors (the zero out run), these impacts (18.90) are below the 3-hour SO₂ Significant Impact level (SIL) of 25 micrograms per cubic meter (µg/m³), demonstrating sources other than Kennecott have a de minimis impact at these receptors.

1
2 When considering the highest impacts (in the form of the standard) at all ambient air receptors
3 (outside Kennecott run), the impacts are less than 20% of the NAAQS. It is noted that these
4 results conservatively include the facility impacts within their fenceline for the other explicitly
5 modeled facilities. The analysis demonstrates that the cumulative impacts at locations of public
6 access are well below the level of the 3-hour SO₂ NAAQS throughout the nonattainment area.



Figure 5: Impacts of 3-Hour SO₂ (H₂H) throughout the nonattainment area.

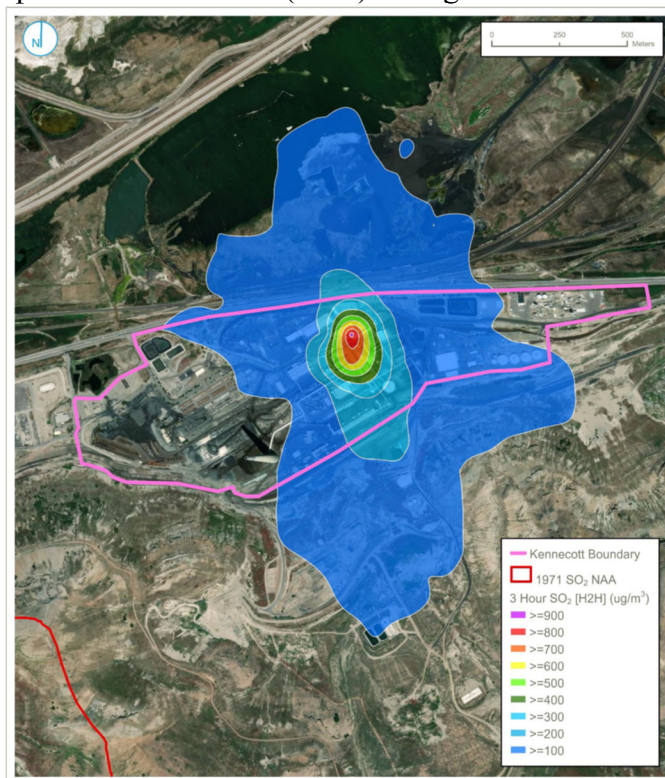


Figure 6: Impacts of 3-Hour SO₂ (H₂H) in the vicinity of the Kennecott facility.

C. 24-Hour Results

The results of the 24-hour modeling are shown in Table 8. Figure 4 and Figure 5 illustrate the impacts nonattainment area-wide, and in the immediate vicinity of Kennecott. The concentrations reported are the highest second-high concentrations in any year, in accordance with the form of the NAAQS. The total impacts are the sum of the modeled value and the background value and are compared to the NAAQS.

Table 8: Results of 24-Hour Modeling

Scenario	Year	Modeled Value (µg/m³)	Background Value (µg/m³)	Total Impact (µg/m³)	NAAQS (µg/m³)
Combined	2024	513.85	7.34	521.19	365
Kennecott zero out	2024	1.20	7.34	8.54	
Outside Kennecott	2024	112.60	7.34	119.94	

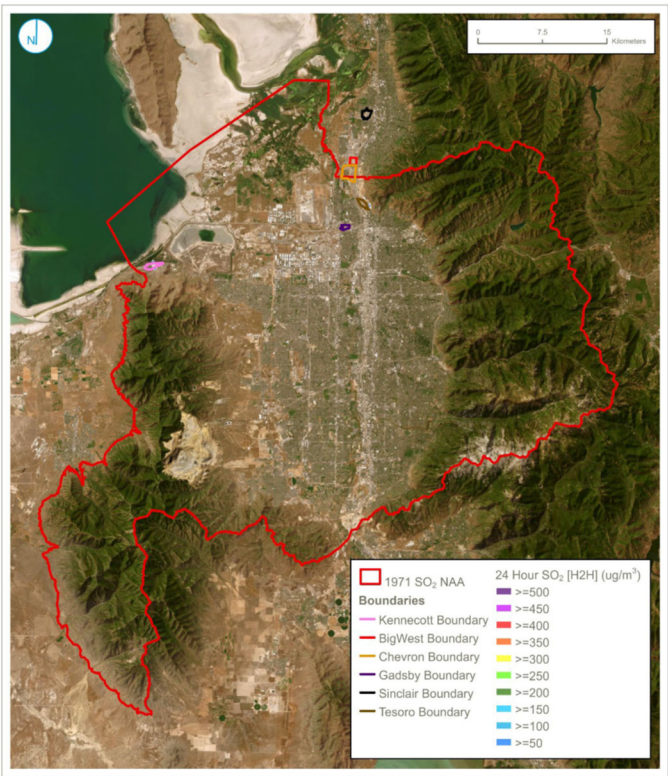


Figure 7: Impacts of 24-Hour SO₂ (H2H) throughout the nonattainment area.

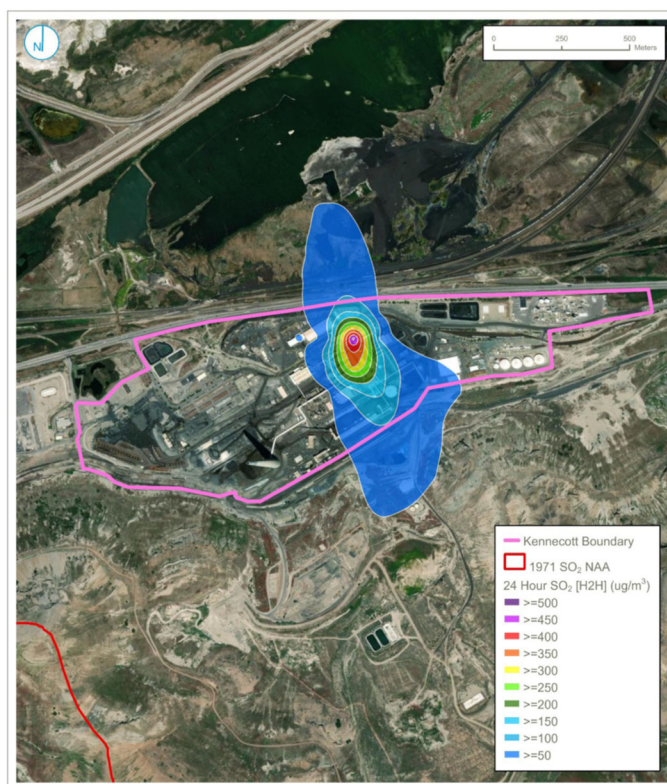


Figure 8: Impacts of 24-Hour SO₂ (H₂H) in the vicinity of the Kennecott facility.

There are two receptors on the Kennecott property that require additional refinement since they are not ambient air to Kennecott. Receptors at (399100, 4509000) and (399100, 4508900) have total impacts that, when including Kennecott emissions, exceed 365 $\mu\text{g}/\text{m}^3$. However, these two receptors are on the Kennecott property, with one on the footprint of the smelter building itself and one immediately adjacent to it. When the Kennecott emissions are excluded in the zero out run, the modeled impacts of the other facilities on the Kennecott property (1.20 $\mu\text{g}/\text{m}^3$) are below the level of the 24-hour SIL (5 $\mu\text{g}/\text{m}^3$), demonstrating that impacts from other facilities are de minimis for the 24-hour standard at these receptors. Accordingly, the 24-hour SO₂ NAAQS is satisfied at all points in the domain, both inside and outside the Kennecott property.

When considering the highest impacts (in the form of the standard) at all ambient air receptors (outside Kennecott run), the impacts are less than 33% of the NAAQS. It is noted that these results conservatively include the facility impacts within their fenceline for the other explicitly modeled facilities. The analysis demonstrates that the cumulative impacts at locations of public access are well below the level of the 24-hour SO₂ NAAQS throughout the nonattainment area.

D. Annual Results

The results of the annual modeling are shown in Table 9. Figure 6 and Figure 7 illustrate the impacts nonattainment area-wide, and in the immediate vicinity of Kennecott. Concentrations reported are the highest annual average in any year, in accordance with the form of the 1971 NAAQS. The total impacts are the sum of the modeled value and the background value and are compared to the NAAQS.

Table 9: Results of Annual Modeling

Scenario	Year	Modeled Value (µg/m ³)	Background Value (µg/m ³)	Total Impact (µg/m ³)	NAAQS (µg/m ³)
Combined	2024	55.00	3.20	58.20	80
Kennecott zero out	2022	0.02	3.20	3.22	
Outside Kennecott	2022	7.13	3.20	10.33	

Total impacts at all receptors are below the NAAQS, even when considering Kennecott's own impacts on its own property. Indeed, as seen in Figure 7, the receptor with the highest impact is at the main smelter and refinery building itself. When the impacts of the other facilities are evaluated at the Kennecott receptors, these impacts (0.02 µg/m³) are below the annual SO₂ SIL of 1 µg/m³, demonstrating sources other than Kennecott have a de minimis impact in this area.

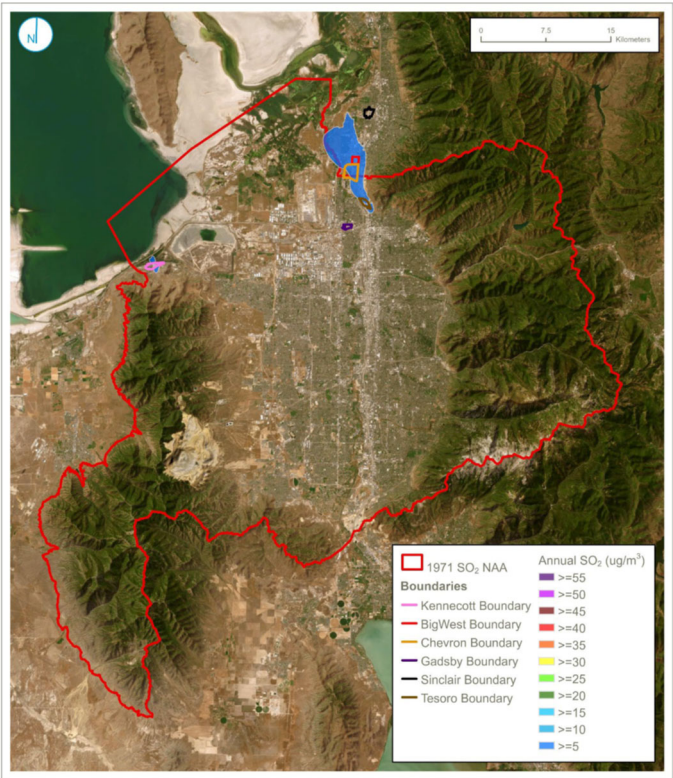
When considering the highest impacts (in the form of the standard) at all ambient air receptors (outside Kennecott run), the impacts are less than 13% of the NAAQS. It is noted that these results conservatively include the facility impacts within their fenceline for the other explicitly modeled facilities. The analysis demonstrates that the cumulative impacts at locations of public access are well below the level of the annual SO₂ NAAQS throughout the nonattainment area.

In 2024, EPA promulgated a new secondary annual SO₂ standard of 10 ppb (26.2 µg/m³)⁵⁰, averaged over the most recent three years. As is demonstrated by the model runs presented here, this standard is easily satisfied throughout the model domain.⁵¹ Assuming the maximum annual impact of 10.33 µg/m³ persists for three consecutive years, the impacts are less than 40% of the new secondary annual NAAQS.

⁵⁰ 89 FR 105692, <https://www.federalregister.gov/documents/2024/12/27/2024-29463/review-of-the-secondary-national-ambient-air-quality-standards-for-oxides-of-nitrogen-oxides-of>.

⁵¹ Results presented in Table 5 are for a single year whereas the new 2024 secondary standard is a multi-year average, so the results presented in Table 5 are in a form that is more conservative than the form of the new NAAQS.

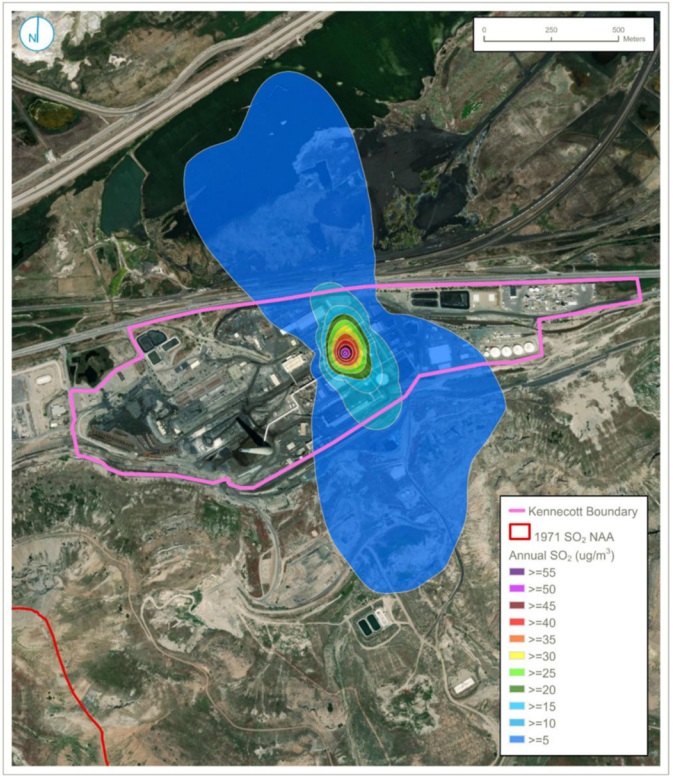
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Figure 9: Impacts of Annual SO₂ (highest single year) throughout the nonattainment area.



4

Figure 10: Impacts of Annual SO₂ (highest single year) in the vicinity of the

E. Discussion

As shown in subsections A through D, the modeled total impacts for the SLC NAA and TC NAA comply with the 1971 NAAQS. The only receptors where concentrations exceeded the level of the NAAQS were on the Kennecott property when modeling all emission units. Once the Kennecott emissions were removed from consideration at those receptors, impacts of the other facilities and background were found to be far below the standards.

At receptors outside the Kennecott boundary, the highest total impacts ranged from about 13% of the standard (annual) to about 33% of the standard (24-hour). Concentrations versus each of the standards considered are far below the NAAQS at locations within ambient air.

The low magnitude of modeled impacts versus the NAAQS provides assurance that NAAQS compliance within the airshed is robust and would be unaffected by different parameterizations in the model setup. For example, as noted in the development of modeled emission rates (Appendix 1), most facilities that were explicitly modeled operate under facility-wide restrictions rather than a series of restrictions applicable to each individual emission unit. Where possible, design capacities of each unit were used to calculate an individualized allowable emission rate for that unit, while remaining unassigned emissions under the facility-wide cap were assigned to units for which an individualized potential emission rate could not be determined. If those units for which individualized totals were able to be calculated were emitting less than their calculated rates, then the amount of unassigned emissions would be greater, and those units receiving the unassigned emissions would then be able to emit at a higher rate.

With modeled impacts at ambient receptors being no more than one-third of any applicable NAAQS, dramatic increases in emission rates – beyond the facility’s permitted levels – would be necessary to obtain concentrations near the level of the NAAQS.

Similarly, there is such ample headroom between the modeled values and the NAAQS that remaining uncertainty in stack parameters should not be a concern. Where the reviewed information contained two different stack parameters for each unit, the lower value of the parameter was chosen for modeling (i.e., lower stack height, smaller release temperature, smaller release velocity, smaller stack diameter). In most instances, the choice of these conservative parameters are expected to result in lower plume rise, less dispersion, and higher modeled concentration. While the central portion of the nonattainment area is relatively flat, there is rugged terrain in the western and eastern portions of the nonattainment areas. Complex terrain may result in local hotspots of higher concentrations at distance from the facility. In the present exercise, it should be emphasized that modeled total impacts at ambient receptors were only 13 to 33 percent of

NAAQS, depending on the particular standard chosen. Given the small magnitude of modeled impacts relative to the NAAQS, there is room if modeled results were to change for a different choice of stack parameters. Additionally, the facility producing the highest absolute impacts (Kennecott) was modeled with stack parameters that were previously reviewed by the EPA, and as seen in Figure 3, Figure 5, and Figure 7, the highest impacts at Kennecott occur at the facility itself rather than at distant hotspots.

In conclusion, the results of this modeling demonstration indicate the Salt Lake-Tooele 1971 SO₂ nonattainment areas are in attainment for the three standards under the 1971 SO₂ NAAQS at facilities' currently permitted SO₂ emission rates.

ii. Fully Approved Applicable Implementation Plan for SO₂

CAA 107(d)(3)(E)(ii) - The Administrator has fully approved the applicable implementation plan for the area under section 110(k). The 1990 amendments to the CAA required states to submit SIP revisions by May 15, 1992, to address nonattainment of the 1971 SO₂ NAAQS. In response, the State submitted revisions to the GEP stack height SIP on December 23, 1991, followed by the revised SO₂ SIP on May 15, 1992. The EPA fully approved both the GEP and SO₂ SIPs, as published in the Federal Register (59 FR 18341) on December 14, 1994.⁵² The SIPs became effective on January 13, 1995. A detailed history of the SIP approval can be found in the Background section of this document.

iii. Improvement in Air Quality Due to Permanent and Enforceable Reductions in Emissions

CAA 107(d)(3)(E)(iii) - The Administrator determines that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions. As discussed in the background section of this document, the SO₂ impact that led to the area's nonattainment designation in 1978 was attributed entirely to Kennecott, and primarily to its smelting process. The history of enforceable emission reductions at Kennecott and improved air quality is discussed below.

(1) Emissions Reductions at Kennecott

Between 1978 and 1995, Kennecott undertook significant modernization of its smelting operations in response to the 1971 SO₂ NAAQS violations and the later PM₁₀ SIP. Kennecott replaced older reverberatory furnaces with Noranda reactors and installed a new single-contact

⁵² Approval and Promulgation of State Implementation Plans, Utah Stack Height Analyses and Regulations, December 14, 1994, 59 FR 18341, www.federalregister.gov/documents/search?conditions%5Bterm%5D=59+FR+18341.

acid plant to control SO₂ emissions from both reactors and converters. A 1,200-foot stack was constructed to improve dispersion and reduce ground-level impacts. Concurrently, improved capture systems and changes in operational practices were made to reduce fugitive emissions. In the 1981 SIP⁵³ submission, the Division revised the Utah administrative rules for air quality to include enforceable SO₂ emission limits for the smelter and associated units, including molybdenite heat treaters, the refinery, and the on-site power plant. RACT was applied to low-level emission sources and fugitive emissions.

As SO₂ is a known precursor to PM₁₀ formation, additional efforts were made to reduce SO₂ emissions as part of the 1991 PM₁₀ SIP. During this period Kennecott implemented further enhancements to the smelting operation, which included replacing the Noranda smelter with flash furnace technology, installing a flash-converting furnace, and upgrading to a double-contact acid plant. These modifications significantly reduced the allowable SO₂ emissions from the main stack from 18,200 lbs/hr to 3,204 lbs/hr.

Table 10 presents Kennecott's emissions from various operational units along with the original 1979 emission inventory. Original emissions are then compared side by side with their federally enforceable emission limits set by the 1981 SO₂ SIP and the 1991 PM₁₀ SIP. A drastic reduction in emissions can be observed at Kennecott from 1979 to 1999 as part of the SIP efforts.

Table 10: Historical SIP enforceable emissions reduction from Kennecott operations

Sources	1979 Emissions* (tpy)	Limits	1981 SO ₂ SIP Limits~	1990 Emissions** (tpy)	1991 PM ₁₀ SIP Limits~	1999 Emissions+ (tpy)
Main Stack	67,900	None	79,700 tpy	22,382	14,200 tpy	629.8
Smelter Fugitives	16,500	None	RACT	4,380	RACT	157.7
Utah Power Plant	4,759	None	0.48 lb/MMBtu	2,905	0.52 lb/MMBtu	2,786.10
Magna Molybdenum Heat Treater	1,988	None	608 tpy	NA	Discontinued	NA
Arthur Molybdenum Heat Treater	1,988	None	608 tpy	NA	Discontinued	NA
Copperton Molybdenum Heat Treater	NA	NA	NA	0.7	115 tpy	0.1
Refinery	1,512	None	512 tpy	4.2	None	0.4
Total	94,647			29,672		3,574

* The 1979 inventory was compiled as part of the 1981 SO₂ SIP revision.

** The 1990 inventory represents the period between the first round of smelter modifications and the second round, which coincided with the PM₁₀ SIP.

+ The 1999 inventory represents the period after the second smelter modification.

⁵³ Utah State Implementation Plan, Section 4.3.2. Regulation for Control of Main Stack SO₂ Emissions (Kennecott Mineral Company), August 16, 1981.

- 1 - The 1981 SIP tpy limits were expressed in lbs/hr (18,200 annual average at the main stack, 139 lbs/hr at each Heat Treater, and 117 lbs/hr at the refinery).
- 2 ~ The 1991 SIP limits come from the PM₁₀ SIP. The tpy limits were expressed in lbs/hr (3,240 lbs/hr annual average at the main stack, 26.2 lb.hr for the Heat Treater at the Copperton Concentrator).

(2) Other Emissions Reductions Measures

As part of the 1992 SO₂ SIP, the State also made significant revisions to Utah Administrative Code Rule R307-203 which regulates sulfur content in fuels (coal, fuel oil, and/or fuel mixtures) from stationary sources. The rule established more stringent emissions standards which stated sulfur emissions shall contain no more than 1.0 lb/MMBtu heat input for any mixture of coal nor 0.85 lb/MMBtu heat input for any oil. In addition, the rule introduced a 24-hour averaging period for determining the sulfur content of these fuels and standardized testing procedures. As SO₂ is considered a precursor pollutant to PM₁₀, PM_{2.5}, and Regional Haze, the State has identified and implemented various emissions reduction measures in the respective SIPs. The SO₂ control measures implemented under Utah SIPs are tabulated below.

Table 11: SIP enforceable SO₂ control measures

Company/Sources	SO ₂ Control Measures	Quantified Reduction
2002 PM₁₀ SIP (Approved)⁵⁴		
Geneva Steel Process	Annual emissions reduced from 1449.3 tpy to 560.2 tpy	889.1 tpy
All Refineries in Salt Lake County and Davis County	Installation of Sulfur Recovery Units (SRU)	95% efficiency
	Restrictions on the burning of liquid fuel oil	
	Low-SO _x catalyst emission reduction techniques	Maximum of 9.8 lbs SO ₂ /1000 lbs coke burn-off
	CEM shall meet the requirements of rule R307-170.	
AMOCO, Flying-J, and Crysen	Emission limits for low process flares	
Flying-J and Crysen	Use of low sulfur content crude	Maximum of 0.24% by weight
Utah County	Ban on all forms of residential coal burning	30% reduction
	Installer and operator training programs for residential solid fuel burning devices	5% reduction

⁵⁴ Utah State Implementation Plan, Section IX, Part A, PM₁₀,
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=551009&eqdocs=%20DAQ-2025-000622&dbid=0&repo=Public>.

	Solid fuel burner inspection program	5% reduction
2014 Moderate Area PM_{2.5} SIP (Approved) - 2015 attainment year data		
Salt Lake City, UT ⁵⁵	R307-302, Solid fuel burning devices	19.16 tpy reduced
	R307-356, Appliance pilot light	1.10 tpy reduced
Provo, UT ⁵⁶	R307-302, Solid fuel burning devices	4.02 tpy reduced
	R307-356, Appliance pilot light	0.19 tpy reduced
Logan, UT ⁵⁷	R307-302, Solid fuel burning devices	2.01 tpy reduced
	R307-356, Appliance pilot light	~0.19 tpy reduced
2019 Serious Area PM_{2.5} SIP (Approved) - 2019 attainment year data ⁵⁸		
Salt Lake City	R307-208, Outdoor Wood Boilers	1.06 tpy reduced
	R307-356, Appliance pilot light	7.88 tpy reduced
	R307-302, Solid fuel burning devices	24.09 tpy reduced
IX.H.1-H.4: PM₁₀ Emission Limits ⁵⁹		
Stack Testing	Stack tests should be performed in accordance with 40 CFR 60, Appendix A, Method 2, 6C, and 19.	
Fluid Catalytic Cracking Units (FCCU)	FCCUs shall comply with an SO ₂ emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.	
Refinery Fuel Gas	Reduce H ₂ S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a.	
Sulfur Recovery Units (SRU)	SRUs shall be at least 95% effective in removing sulfur and meet limitations listed in 40 CFR 60.102a(f)(1) or 60.102a(f)(2).	
	Amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).	
Liquid Fuel Oil	Liquid fuel oil shall not be allowed to burn in stationary sources except during natural gas curtailments.	
	Diesel fuel shall meet the specification of 40 CFR 1090.305.	

⁵⁵ Utah State Implementation Plan, Section IX, Part A.21, PM_{2.5},
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=479906&eqdocs=%20DAQ-2024-011602>.

⁵⁶ Utah State Implementation Plan, Section IX, Part A.22, PM_{2.5},
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=479904&eqdocs=%20DAQ-2024-011604>.

⁵⁷ Utah State Implementation Plan, Section IX, Part A.23, PM_{2.5},
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=479910&eqdocs=%20DAQ-2024-011601>.

⁵⁸ Utah State Implementation Plan, Section IX, Part A.31, PM_{2.5},
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=385732&eqdocs=%20DAQ-2019-005386>.

⁵⁹ Utah State Implementation Plan, Section IX, Part H,
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=560211&eqdocs=%20DAQ-2025-001221&dbid=0&repo=Public>.

Hydrocarbon Flares	Flares are subject to NSPS Subpart Ja.	
	Install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c) or limit flaring during normal operations to 500,000 scfd for each affected flare.	
Big West Oil Company	Source-wide SO ₂ cap	Not to exceed 0.60 tons per day (tpd) and 140 ton per rolling 12-month period
	Alternate Startup and Shutdown Requirements	Combined emissions of SO ₂ shall not exceed 1.2 tpd
	The total number of days which include startup or shutdown of the FCCU shall not exceed ten (10) per 12-month rolling period.	
	Refinery flares shall meet Subpart Ja and MACT CC flaring standards.	
	Product loading racks shall be controlled by vapor recovery and vapor combustors.	
	Interim Emission Limits: Combined emissions of SO ₂ from all external combustion process equipment between October 1 - March 31	Not to exceed 2.764 tpd
	Interim Emission Limits: Combined emissions of SO ₂ from all external combustion process equipment between April 1 - September 30	Not to exceed 3.639 tpd
Chevron Products Company	Source-wide SO ₂ cap	Not to exceed 1.05 tpd and 383.3 tons per rolling 12-month period
	Sulfur Recovery Unit #1 and #2 shall be controlled by a tail gas treatment unit and tail gas incineration.	
	Flare #1 and #2 shall be controlled by a flare gas recovery system.	
	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment.	Not to exceed 0.5 tpd
Hexcel Corporation	Natural gas consumption	Not to exceed 5.50 MMscf per day

Holly Refining and Marketing Company	Source-wide SO ₂ cap	Not to exceed 0.31 tpd and 110.3 tons per rolling 12-month period
	Sulfur recovery unit shall be controlled by tail gas incineration.	
	Interim Emission Limits: Combined emissions of SO ₂ from all sources	Not to exceed 4.714 tpd
Kennecott Utah Copper	Diesel-powered ore and waste haul trucks	Not to exceed 30,000 miles per day
	Smelter Main Stack (Stack #11) emission	Not to exceed 552 lbs/hr 3-hour rolling average
		Not to exceed 422 lbs/hr daily average
	Main Stack (Stack #11) shall have SO ₂ CEMs installed and meet the requirements of rule R307-170.	
	Power Plant Unit #4 shall only use natural gas as fuel, unless the supplier or transporter of natural gas imposes a curtailment.	
	Sulfur content of any fuel burned	Not to exceed 0.66 lbs of sulfur per MMBtu per test
Tesoro Refining & Marketing Company	Source-wide SO ₂ cap	Not to exceed 3.8 tpd and 300 tons per rolling 12-month period
	SRU/TGTU/TGI	Not to exceed 1.68 tpd for up to 21 days per rolling 12-month period and 0.69 tpd for the remainder of the rolling 12-month period
	North and South Flares shall be controlled by a flare gas recovery system.	
	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment between November 1 - End of February	3.699 tpd
	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment between March 1 - October 31	4.374 tpd
Gadsby Power Plant	Steam generating units #1, #2, #3 shall only use natural gas as fuel, unless the supplier or transporter of natural gas	

	imposes a curtailment and for maintenance firings.	
Brigham Young University	Central Heating Unit #2, #3 and #5	Not to exceed 597 ppm (7% O ₂ dry)
	Central Heating Plant Coal-Fired Boilers	Not to exceed 0.54 lbs of sulfur per MMBtu or 0.60% by weight
	Inspect fuel sulfur weight % and fuel heating value by submitting a coal sample to a laboratory using methods of ASTM, or inspecting vendor documentation.	
IX.H.11-H.13: PM_{2.5} Emission Limits ⁶⁰		
Stack Testing	Stack tests should be performed in accordance with 40 CFR 60, Appendix A, Method 2, 6C, and 19.	
Fluid Catalytic Cracking Units (FCCU)	FCCUs shall comply with an SO ₂ emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.	
Refinery Fuel Gas	Reduce H ₂ S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a.	
Hydrocarbon Flares	Flares are subject to NSPS Subpart Ja.	
	Install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c) or limit flaring during normal operations to 500,000 scfd for each affected flare.	
Liquid Fuel Oil	Liquid fuel oil shall not be allowed to burn in stationary sources except during natural gas curtailments.	
	Diesel fuel shall meet the specification of 40 CFR 1090.305.	
Big West Oil Company	Alternate Startup and Shutdown	Combined emissions of SO ₂ shall not exceed 1.2 tpd
	The total number of days which include startup or shutdown of the FCCU shall not exceed ten (10) per 12-month rolling period.	
	Refinery flares shall meet Subpart Ja and MACT CC flaring standards.	

⁶⁰ Utah State Implementation Plan, Section IX.H.11-H.13,
<https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=585532&eqdocs=%20DAQ-2025-001223>.

	Product loading racks shall be controlled by vapor recovery and vapor combustors.	
Chevron Products Company	Sulfur Recovery Units #1 and #2 shall be controlled by a tail gas treatment unit and tail gas incineration.	
	Flare #1 and #2 shall be controlled by a flare gas recovery system.	
Hexcel Corporation	Natural gas consumption	Not to exceed 5.50 MMscf per day
HF Sinclair Woods Cross Refinery	Refinery flares shall be controlled by flare gas recovery system.	
	Sulfur recovery unit shall be controlled by tail gas incineration.	
Kennecott Utah Copper	Diesel-powered ore and waste haul trucks	Not to exceed 30,000 miles per day
	Power Plant Unit #4 shall only use natural gas as fuel, unless the supplier or transporter of natural gas imposes a curtailment.	
	Smelter Main Stack (Stack #11) SO ₂ emission	Not to exceed 552 lbs/hr 3hr. rolling average
		Not to exceed 422 lbs/hr daily average
	The Main Stack (Stack #11) shall have SO ₂ CEMs installed and meet the requirements of R307-170.	
	Electric Arc Furnace Baghouse shall have CEM installed and meet the requirements of R307-170.	
Nucor Steel Mills	SO ₂ emission	Not to exceed 93.98 lbs/hr 3-hour rolling average
		Not to exceed 89.00 lbs/hr daily average
Tesoro Refining & Marketing Company	SRU/TGTU/TGI	Not to exceed 1.68 tpd for up to 21 days per rolling 12-month period and 0.69 tpd for the remainder of the rolling 12-month period
	North and South Flares shall be controlled by flare gas recovery system.	
	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment between November 1 - End of February	3.699 tpd

	Interim Emission Limits: Combined emissions of SO ₂ from gas-fired compressor drivers and all external combustion process equipment between March 1 - October 31	4.374 tpd
Gadsby Power Plant	Steam generating unit #1, #2, #3 shall only use natural gas as fuel, unless the supplier or transporter of natural gas imposes a curtailment or for maintenance firings.	
University of Utah	Boilers #1, #3, and #4 natural gas usage	Not to exceed 530 MMscf per calendar year
Brigham Young University	Central Heating Unit #2, #3 and #5	Not to exceed 597 ppm (7% O ₂ dry) lbs/hr
	Sulfur content of central heating plant coal-fired boilers	Not to exceed 0.54 lbs/MMBtu
	Inspect fuel sulfur weight % and fuel heating value by submitting a coal sample to a laboratory.	

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iv. State has Met Requirements of Section 110 and Part D

CAA 107(d)(3)(E)(v) – The State containing such area has met all requirements applicable to the area under section 110 and part D. Section 110 of the Act deals with the broad scope of the state implementation plans and the capacity of the respective state agency to effectively administer such a plan. Part D deals specifically with plan requirements for nonattainment areas, including those requirements that are specific to SO₂.

(1) Section 110

The State has met all requirements applicable to the TC NAA area under Section 110 of the CAA. Section 110(a)(2) contains the general requirements or infrastructure elements necessary for EPA approval of the SIP. On June 2, 2013, the State submitted an Infrastructure SIP to the EPA demonstrating compliance with the requirements of Section 110 that are applicable to the 2010 SO₂ NAAQS.⁶¹ The EPA approved the State’s Infrastructure SIP on October 22, 2018 (83 FR 47566) for all Section 110 requirements that are applicable to redesignation.⁶²

(2) Part D Subpart 1 and 5

Part D of the CAA addresses “Plan Requirements for Nonattainment Areas.” Subparts 1 and 5 of Part D contain planning elements that must be included in the SIP. This includes emissions inventories, control measures (including reasonably available control technology), permits for major new or modified sources, enforceable emissions limits, schedules of compliance, and contingency measures if progress is inadequate. On May 15, 1992, the State submitted a revised SO₂ SIP adequately addressing each of the above-mentioned elements. The SIP was fully approved by the EPA on December 14, 1994, which suggests Utah has complied with all applicable Part D requirements.⁶³

v. Maintenance Plan

As stated in the CAA, an area may not be redesignated to attainment without first submitting and receiving EPA approval of a maintenance plan. The maintenance plan is a quantitative analysis showing that the area will continue to attain the NAAQS for an additional 10 years (from EPA

⁶¹ State of Utah 110(a)(2) SIP Infrastructure Elements for SO₂ (2013), <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=572027&eqdocs=%20DAQ-2025-002449&dbid=0&repo=Public>.

⁶² Air Quality State Implementation Plans, Approvals and Promulgations: Infrastructure Monitoring Requirements for the 2008 Pb, 2010 SO₂, 2010 NO₂ and 2012 PM_{2.5} National Ambient Air Quality Standards, Utah, October 22, 2018, <https://www.federalregister.gov/documents/2018/09/20/2018-20448/air-quality-state-implementation-plans-approvals-and-promulgations-infrastructure-monitoring>.

⁶³ Approval and Promulgation of State Implementation Plans, Utah Stack Height Analyses and Regulations, December 14, 1994, 59 FR 18341, www.federalregister.gov/documents/search?conditions%5Bterm%5D=59+FR+18341.

approval), accompanied by sufficient assurance that the terms of the numeric demonstration will be administered by the State and by the EPA in an oversight capacity. The maintenance plan is the central criterion for redesignation. It is contained in the following Section.

IX.B.12.d Maintenance Plan

CAA 107(d)(3)(E)(iv) – *The administrator has fully approved a maintenance plan for the area as meeting the requirements of section 175A.* An approved maintenance plan is one of several criteria necessary for area redesignation as outlined in Section 107(d)(3)(E) of the CAA. The maintenance plan itself, as described in Section 175A of the CAA and further addressed in EPA guidance⁶⁴, has its own list of required elements. The following table is presented to summarize these requirements. Each will then be addressed in turn.

Table 12: Maintenance Plan Requirements in the Federal Clean Air Act

Category	Requirement	Reference	Addressed in Section
Maintenance Demonstration	Provide for maintenance of the relevant NAAQS in the area for at least 10 years after redesignation.	CAA §175A(a)	IX.B.12.d(i)
Revise in 8 Years	The State must submit an additional revision to the plan, 8 years after redesignation, showing an additional 10 years of maintenance.	CAA §175(b)	IX.B.12.d(ii)
Continued Implementation of Nonattainment Area Control Strategy	The CAA requires continued implementation of the nonattainment area control strategy unless such measures are shown to be unnecessary for maintenance or are replaced with measures that achieve equivalent reductions.	CAA §175A(c), Calcagni memo	IX.B.12.d(iii)
Contingency Measures	Areas seeking redesignation from nonattainment to attainment are required to develop contingency measures that include State commitments to implement additional control measures in response to future violations of the NAAQS.	CAA §175A(d)	IX.B.12.d(iv)

⁶⁴ John Calcagni, September 4, 1992, EPA Memorandum “Procedure for Processing Requests to Redesignate Areas to Attainment” https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf

Category	Requirement	Reference	Addressed in Section
Verification of Continued Maintenance	The maintenance plan must indicate how the State will track the progress of the maintenance plan.	Calcagni memo	IX.B.12.d(v)

1

2 i. Demonstration of Maintenance – Attainment Inventory

3 *CAA 175A(a) – Each State which submits a request under Section 107(d) for redesignation of a*
4 *nonattainment area as an area which has attained the NAAQS shall also submit a revision of the*
5 *applicable implementation plan to provide for maintenance of the NAAQS for at least 10 years*
6 *after the redesignation. The plan shall contain such additional measures, if any, as may be*
7 *required to ensure such maintenance.* The maintenance demonstration is discussed in the EPA
8 guidance⁶⁵ as one of the core provisions that should be considered by the states for inclusion in a
9 maintenance plan.

10

11 According to the EPA guidance, a state may generally demonstrate maintenance of the NAAQS
12 by either showing that future emissions of a pollutant or its precursors will not exceed the level
13 of the attainment inventory or by modeling to show that the future mix of sources and emission
14 rates will not cause a violation of the NAAQS.

15

16 As discussed in Section IX.B.12.c(i)(2) – Modeling Element of this document, Utah has
17 provided a modeling demonstration evaluating continued attainment of the NAAQS using the
18 highest allowable emissions from six point sources in and near the nonattainment area. In
19 addition to that analysis, Utah is providing an attainment inventory-based demonstration of
20 maintenance. Under this approach, projected future emissions at the highest allowable levels are
21 compared to the base-year attainment inventory to show that the emissions are expected to
22 remain at or below levels consistent with continued attainment.

23

24 Consistent with the guidance, the projection inventory should consider future growth, including
25 population and industry, should be consistent with the base-year inventory, and should document
26 data inputs and assumptions. Any assumption concerning emission rates must reflect permanent,
27 enforceable measures.

28

⁶⁵ John Calcagni, September 4, 1992, EPA Memorandum “Procedure for Processing Requests to Redesignate Areas to Attainment” https://www.epa.gov/sites/default/files/2016-03/documents/calcagni_memo_-_procedures_for_processing_requests_to_redesignate_areas_to_attainment_090492.pdf.

The Division chose 2023 as the base year for inventory analysis presented in this section because it was the most recent triennial inventory year available for all source categories. The base-year emissions inventory is a comprehensive, accurate, and current inventory of actual emissions for all sources in the nonattainment area plus any sources located outside the nonattainment area that may affect attainment.⁶⁶ The 2023 base-year emissions inventory is projected to 2040 to demonstrate maintenance of the NAAQS. The year 2040 is chosen to allow at least 10 years of maintenance period after final EPA redesignation. The emissions contained in the inventories include sources located in Salt Lake and Tooele Counties.⁶⁷ Emissions from three point sources in Davis County (adjacent to Salt Lake County) are also included in the maintenance demonstration.⁶⁸ These sources were determined to be significant by the EPA for the attainment demonstration and were therefore included in both the modeling analysis and the inventory projection.

There are four general categories of sources included in the inventory: point source, area source, on-road mobile source, and non-road mobile source. All inventories are developed in accordance with the Air Emissions Reporting Requirements (40 CFR Part 51, Subpart A). Emissions recorded for each sector are presented in tons per year.

The point source category consists of all stationary sources subject to Utah Emissions Inventory Reporting Rule R307-150, including both major (>100 tpy) and minor (<100 tpy) SO₂ emission sources in Salt Lake and Tooele counties.⁶⁹ Stationary sources that are not subject to Rule R307-150 are classified under the area source category. The area source category also includes emissions estimates for sources that are individually too small to be reported as point sources but collectively contribute to total SO₂ emissions within the SO₂ nonattainment areas. Notable examples include combustion activities, agricultural burning, and wildfires.

On-road mobile sources include emissions from motorized vehicles that typically operate on public roadways, such as passenger vehicles, light-duty trucks, heavy-duty trucks, and buses. Non-road mobile sources include yard care equipment, construction equipment, recreational engines, and portable industrial, commercial, and agricultural engines. Emissions from both on-road and non-road mobile sources were developed using the EPA-approved Motor Vehicle Emission Simulator, version 5 (MOVES5).⁷⁰

⁶⁶ Table 13, 14, and 15 of this document.

⁶⁷ Table 13: SO₂ emissions inventory for Salt Lake and Tooele counties by source category in tons per year.

⁶⁸ Table 14 and 15 of this document.

⁶⁹ R307-150 Emissions Inventory

<https://adminrules.utah.gov/public/rule/R307-150/Current%20Rules?searchText=R307-150>.

⁷⁰ MOVES5 5.0.1-movesdb20241112

<https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves>.

Emissions inventory Table 13 shows baseline point source emissions from 1979 which were compiled as part of the 1981 SO₂ SIP effort.⁷¹ Area source emissions were projected to 2040 from the 2023 triannual inventory. Growth data from appropriate data sources, including information from the Governor's Office of Management and Budget, was used for the projection. Point source emissions are represented as the actual emissions from the 2023 triannual emissions inventory. Point sources were grown from 2023 to 2040 on a case-by-case basis for the projection inventories. On-road and non-road mobile source emissions were projected using MOVES5.

Table 13: SO₂ emissions inventory for Salt Lake and Tooele counties by source category in tons per year

Nonattainment Area Inventory Projection (tpy) ⁺												
	1979	1996	1999	2002	2005	2008	2011	2014	2017	2020	2023	2040
Area Sources	*	41.10	1,162.81	292.67	158.54	200.43	595.85	23.65	146.84	192.51	150.51	158.36
Non-Road Mobile	*	198.52	*	536.67	583.13	353.24	247.16	130.25	183.34	2.99	168.75	226.94
On-Road Mobile	*	0.00	927.36	855.61	608.61	86.35	120.84	103.82	108.60	32.19	33.65	18.60
Point Source**	112,994.17	4,959.54	5,108.81	4,771.65	4,998.86	5,955.08	3,467.53	3,076.37	2,250.27	631.55	560.15	588.35
Total	112,994.17	5,199.16	7,198.98	6,456.60	6,349.14	6,595.10	4,431.38	3,334.09	2,689.05	859.24	913.06	992.25

*Data not available

⁺Does not include emissions from Davis County sources

Total SO₂ emissions in the Utah SO₂ nonattainment area have declined dramatically since 1979, decreasing from approximately 113,000 tpy to about 913 tpy in 2023, representing a reduction of more than 99%. Early emissions were dominated by large industrial point sources, which accounted for nearly all SO₂ emissions in 1979. Substantial reductions occurred through the 1980s and 1990s as major facilities implemented enforceable emission limits and control technologies. Continued declines after 2000 reflect additional controls, operational changes, and improved compliance with federal and state permitting requirements. Since 2023, point sources remain the primary contributors but at significantly reduced levels, while area, on-road mobile, and non-road mobile sources collectively contribute a relatively small portion of total emissions.

The observed reductions are primarily attributed to implementation of the approved SIPs⁷², which required the application of RACT under moderate SIP and Best Available Control

⁷¹ 1979 Baseline Emissions Inventory, 1981 SO₂ SIP, <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=612086&dbid=0>.

⁷² Utah State Implementation Plans, <https://deq.utah.gov/air-quality/sections-state-implementation-plan-sip>.

Technology under serious SIP and facility-specific emission limits⁷³ for major SO₂ sources. Additional reductions resulted from federal fuel sulfur standards and mobile-source regulations that substantially lowered sulfur content in fuels^{74, 75}, leading to near elimination of SO₂ emissions from on-road engines. Changes in the petroleum refinery industry, including fuel switching and installation of sulfur control equipment, further contributed to long-term emission decreases.⁷⁶

Between 2023 and 2040, total SO₂ emissions in the nonattainment area are projected to increase modestly from 913.06 tpy to 992.25 tpy (approximately 9%), while remaining substantially below historical levels associated with prior nonattainment. Point source actual emissions, which constitute the largest share of the inventory, are projected to increase slightly from 560.15 tpy in 2023 to 588.35 tpy in 2040 due to anticipated industrial activity and economic growth. However, emissions from these sources remain subject to permanent and federally enforceable permit limits established in facility Approval Orders. These limits represent the maximum allowable emissions for each facility and are not expected to increase by 2040. The projected 2040 point source emissions of 588.35 tpy remain well below the facility-wide maximum allowable emission limits used in the attainment modeling.⁷⁷ This relationship demonstrates that even with modest growth in actual emissions, emissions remain within the bounds evaluated in the attainment demonstration.

Non-road mobile source emissions are projected to increase from 168.75 tpy to 226.94 tpy, largely attributable to projected growth in airport-related activity within the non-road sector. In contrast, on-road mobile source emissions are projected to decline from 33.65 tpy to 18.60 tpy as a result of continued fleet turnover and implementation of federal vehicle emission standards and ultra-low sulfur fuel requirements. Area source emissions are projected to increase slightly from 150.51 tpy to 158.36 tpy, consistent with anticipated population and commercial growth.

Emissions projections through 2040 indicate that total SO₂ emissions are expected to remain low and stable under existing regulatory programs, providing assurance that the maintenance area will continue to comply with the current SO₂ NAAQS which is considerably more stringent than the 1971 standards.⁷⁸ These trends demonstrate that the emission reductions are permanent, surplus, and enforceable, and that the proposed maintenance area is well positioned to maintain attainment throughout the maintenance period.

⁷³ SO₂ Maintenance Plan, Table 11: SIP enforceable SO₂ control measures.

⁷⁴ 1090.205 Sulfur standards, 40 CFR 1090.205, <https://www.ecfr.gov/current/title-40/section-1090.205>.

⁷⁵ ULSD Standards, 40 CFR 1090.305, <https://www.ecfr.gov/current/title-40/section-1090.305>.

⁷⁶ Standards of Performance for Petroleum Refineries, 40 CFR Part 60 Subpart Ja, <https://www.ecfr.gov/current/title-40/part-60/subpart-Ja>.

⁷⁷ Section IX.B.12.c(i)(2) The Area Has Attained the 1971 SO₂ NAAQS: Modeling Element

⁷⁸ SO₂ NAAQS, <https://www.epa.gov/so2-pollution/timeline-sulfur-dioxide-naaqs>.

Table 14: 2023 actual, 2040 projected, and maximum allowable SO₂ emissions for six explicitly modeled sources. Maximum allowable emission limits are held constant between 2023 and 2040.

Explicitly Modeled Sources	2023 Actual Emissions	2040 Projected Emissions	2023 & 2040 Maximum Allowable Emission Limits
Kennecott Smelter and Refinery	429.49	442.66	1,090.27
Gadsby Power Plant	1.16	0.88	75.00
Tesoro Refinery	17.60	18.14	300.01
Chevron Refinery*	37.58	38.73	384.70
Big West Refinery*	70.54	72.70	140.14
HF Sinclair Refinery*	12.17	12.55	84.10
Total	568.54	585.66	2,074.22

*Located in Davis County.

Table 14 summarizes 2023 actual SO₂ emissions and projected 2040 emissions for the six explicitly modeled stationary sources⁷⁹ in and near the nonattainment area, along with their maximum allowable emission limits. In 2023, total actual emissions from these sources were 568.54 tpy. Emissions are dominated by the Kennecott Smelter and Refinery (429.49 tpy), with the remaining facilities contributing comparatively smaller amounts. The combined maximum allowable emission limits for these six sources are 2,074.22 tpy, indicating that actual emissions are well below allowable levels and that significant compliance margins exist for each facility.

Projected 2040 emissions total 585.66 tpy, representing a modest increase of approximately 3% from 2023 actual emissions inventory levels. Individual facility projections show only minor changes, and total maximum allowable emission limits remain unchanged through 2040. Overall, projected emissions remain substantially below the maximum allowable emission limits.

The dispersion modeling conducted for the attainment demonstration used 2023 maximum allowable emission limits and the results show that the area meets the applicable SO₂ NAAQS. Emissions from these six explicitly modeled sources represent the primary contributors of SO₂, while all other emission sources in the nonattainment area accounted for in the background concentration used in the modeling analysis. Because 2040 maximum allowable emission limits remain unchanged and are comparable to the emissions levels used in the attainment modeling, similar dispersion modeling results would be expected under 2040 conditions. These data support the conclusion that SO₂ emissions from explicitly modeled sources are expected to

⁷⁹ Section IX.B.12.c(i)(2) The Area Has Attained the 1971 SO₂ NAAQS: Modeling Element

1 remain stable over the maintenance period and that continued maintenance of the SO₂ NAAQS
2 through 2040 is reasonably assured. Facility-wide maximum allowable emission limits and
3 compliance with NAAQS have been discussed in detail in the modeling chapter in Section
4 IX.B.12.c(i)(2) which supports the same conclusion.
5
6

1 Table 15: Triennial actual SO₂ emissions inventory for six explicitly modeled sources covering
 2 1996–2023, with forward projections from 2023 through 2040.

	1996	1999	2002	2005	2008	2011	2014	2017	2020	2023 Base- year	2040 Projection
Kennecott Smelter and Refinery	1,555.30	789.19	938.75	777.27	970.08	696.89	703.14	587.95	428.87	429.49	442.66
Gadsby Power Plant	0.60	1.70	1.90	0.56	1.95	0.81	1.52	0.46	0.59	1.16	0.88
Tesoro Refinery	982.63	1107.10	712.12	879.66	931.90	795.31	708.30	499.46	22.56	17.60	18.14
Chevron Refinery*	1,115.60	791.93	1,332.00	2,200.66	591.85	24.31	23.89	32.38	37.65	37.58	38.73
Big West Refinery*	573.87	441.66	272.48	360.77	377.39	188.71	57.14	55.43	50.63	70.54	72.70
HF Sinclair Refinery*	864.05	787.67	451.90	574.09	452.99	131.03	102.33	44.35	20.04	12.17	12.55
Total	5,092.05	3,919.25	3,709.15	4,793.01	3,326.16	1,837.06	1,696.32	1,220.03	560.34	568.54	585.66

3 *Located in Davis County.

4
 5 Table 15 provides another look at the long-term emission trends, the magnitude of reductions
 6 achieved, and the stability of emissions inventory through the maintenance period. The table
 7 presents triennial actual SO₂ emissions for the six explicitly modeled stationary sources from
 8 1996 through 2023, along with projected emissions through 2040. The data show a substantial
 9 long-term downward trend in emissions across the nonattainment area. Total emissions declined
 10 from 5,002.05 tpy in 1996 to 568.54 tpy in the 2023 base year, representing an overall reduction
 11 of approximately 89%. The most significant reductions occurred between 2008 and 2017 and are
 12 primarily attributable to process changes, fuel switching, installation of control technologies, and
 13 enforceable AO limits at the point source facilities.

14
 15 Emissions have remained relatively stable in recent years, with totals of 560.34 tpy in 2020 and
 16 568.54 tpy in 2023. Projected emissions for 2040 are 585.66 tpy, reflecting only a modest
 17 increase over the base-year of 2023. Individual facility projections show minor changes, and
 18 overall emissions remain far below historical levels and facility-wide maximum allowable
 19 emission limits. The long-term downward trend and the stability of recent and projected
 20 emissions inventory further support the conclusion that the area has attained the SO₂ NAAQS
 21 and is expected to continue to maintain the standard through 2040.

ii. Revise in Eight Years

CAA 175A(b) – 8 years after redesignation of any area as an attainment area, the State shall submit an additional revision of the applicable plan for maintaining the national primary ambient air quality standard for 10 years after the expiration of the 10-year period. Utah commits to submit a revised maintenance plan eight years after the EPA takes final action redesignating Tooele County area to attainment, as required by the CAA.

iii. Nonattainment Requirements Applicable Pending Plan Approval

CAA 175A(c) – Until such plan revision is approved and an area is redesignated as attainment, the requirements of CAA Part D, Plan Requirements for Nonattainment Areas, shall remain in force and effect. The CAA requires the continued implementation of the nonattainment area control strategy unless such measures are shown to be unnecessary for maintenance or are replaced with measures that achieve equivalent reductions. Utah will continue to implement the emissions limitations and measures from the SO₂ SIP.

iv. Contingency Plan

CAA 175A(d) – Each maintenance plan shall contain contingency measures to assure that the State will promptly correct any violation of the standard which occurs after the redesignation of the area to attainment. Such provisions shall include a requirement that the State will implement all control measures which were contained in the SIP prior to redesignation.

The contingency plan must also ensure that the contingency measures are adopted expeditiously once triggered. The primary elements of the contingency plan are: 1) the list of potential contingency measures; 2) the tracking and triggering mechanisms to determine when contingency measures are needed; and 3) a description of the process for recommending and implementing the contingency measures.

Tracking

The tracking plan for the Salt Lake County and part of Tooele County nonattainment area consists of monitoring and analyzing ambient SO₂ concentrations. In accordance with 40 CFR 58, the State will continue to operate and maintain an adequate SO₂ monitoring network in the nonattainment area.

Triggering

Triggering of the contingency plan does not automatically require a revision to the SIP, nor does it mean that the area will automatically be redesignated once again to nonattainment. Instead, the State will have an appropriate timeframe to correct the potential violation with implementation

1 of one or more adopted contingency measures. In the event that violations continue to occur,
2 additional contingency measures will be adopted until the violations are corrected.

3
4 Upon notification of a potential violation of the SO₂ NAAQS, the State will develop appropriate
5 contingency measures intended to prevent or correct violation of the standard. Information about
6 historical exceedances of the standard, the meteorological conditions related to the recent
7 exceedances, and the most recent estimates of growth and emissions will be reviewed. The
8 possibility that an exceptional event occurred will also be evaluated.

9
10 Upon monitoring a potential violation of the SO₂ NAAQS, including exceedances flagged as
11 exceptional events but not concurred with by EPA, the State will identify a means of corrective
12 action within six months after a potential violation. The maintenance plan contingency measures
13 will be chosen from the following list based on consideration of cost-effectiveness, emission
14 reduction potential, economic and social considerations, or other factors that the State deems
15 appropriate:

- 16 • Re-evaluate the permissible sulfur content of fuels for commercial and industrial sources,
17 as established in Rule R307-203.
- 18 • Further controls on the stationary sources in the nonattainment area that are listed below:
 - 19 ○ Kennecott Smelter and Refinery;
 - 20 ○ Gadsby Power Plant;
 - 21 ○ Tesoro Refinery;
 - 22 ○ Chevron Refinery;
 - 23 ○ Big West Refinery; and
 - 24 ○ HF Sinclair Refinery.

25
26 The State will then hold a public hearing to consider the contingency measures identified to
27 address the potential violation. The State will require implementation of such corrective action
28 no later than one year after the violation is confirmed. Any contingency measures adopted and
29 implemented will become part of the next revised maintenance plan submitted to the EPA for
30 approval.

31 v. Verification of Continued Maintenance and Monitoring

32 Implicit in the requirements outlined above is the need for the State to determine whether the
33 area is in fact maintaining the standard it has achieved. There are two complementary ways to
34 measure this: 1) by monitoring the ambient air for SO₂; and 2) by inventorying emissions of SO₂
35 from various sources.

36
37 The State will continue to maintain an ambient monitoring network for SO₂ in accordance with
38 40 CFR Part 58 and the Utah SIP. The State anticipates that the EPA will continue to review the

1 ambient monitoring network for SO₂ each year, and any necessary modifications to the network
2 will be implemented.

3
4 Additionally, the State will track new and modified stationary source permits. If the resulting
5 emissions change significantly over time, the State will perform appropriate studies to determine:
6 1) whether additional and/or re-sited monitors are necessary; and 2) whether stationary source
7 emission projections are on target. The State will also continue to collect actual emissions
8 inventory data from sources at thresholds defined in Rule R307-150 and will review and update
9 the annual emissions inventory for the nonattainment area at a minimum of once every three
10 years to ensure continued maintenance of the SO₂ standard.

ITEM 6



State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-007-26

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

THROUGH: Jazmine Lopez, Rules Coordinator

FROM: Sheila Vance, Environmental Scientist

DATE: March 17, 2026

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend Section R307-110-13 to incorporate Utah State Implementation Plan Section IX, Control Measures for Area and Point Sources, Part D, Ozone; Section IX.D.13.a, 2020 Uinta Basin Periodic Inventory Report and Section IX.D.13.b, 2023 Uinta Basin Periodic Inventory Report.

Per the Clean Air Act (CAA), marginal ozone nonattainment areas are required to submit periodic emission inventories as part of their State Implementation Plan (SIP) to track progress in reducing emissions until the area is redesignated to attainment.¹ These inventories, required under CAA § 182(a)(3)(A), must be submitted every three years following the initial base year inventory until the area is redesignated to attainment. The Uinta Basin (UB) was designated as a marginal ozone nonattainment area (NAA) in August 2018.² The required base-year emission inventory for 2017 was submitted to and approved by EPA.³ The Utah Division of Air Quality has completed the required periodic emission inventories for the years 2020 and 2023. These periodic emission inventories are required to be incorporated into Utah State Implementation Plan,⁴ Section IX, Control Measures for Area and Point Sources, Part D, Ozone through Rule R307-110-13.

¹ 40 CFR 51.1315(b)

² Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards; 83 FR 25776; EPA-HQ-OAR-2017-0548; FRL-9977-72-OAR.

³ Approval and Promulgation of Implementation Plans; Utah; 2017 Base Year Inventories for the 2015 8-Hour Ozone National Ambient Air Quality Standard for the Uinta Basin, Northern Wasatch Front and Southern Wasatch Front Nonattainment Areas, 2021-14195 (86 FR 35404).

⁴ 40 CFR Part 52 Subpart A

In March 2023, the state of Utah requested that EPA extend the attainment date for the UB NAA by a second year, at which time the area had a monitored design value that met attainment. In December 2024, EPA denied the request and reclassified the area to moderate nonattainment.⁵ In February 2025, the state of Utah requested that EPA reconsider their December 2024 decision and filed in court a request for a stay of the decision. EPA agreed to reconsider the December 2024 decision and a judicial stay was granted. These decisions leave the UB NAA in a marginal NAA status currently and all CAA requirements for a marginal NAA remain in place. The CAA requires states to comply with all required SIP elements to be eligible for a second one-year extension.⁶ Therefore, these required periodic emission inventories must be incorporated into our SIP to support EPA's reconsideration of our second one-year extension request that they are currently evaluating.

Recommendation: Staff recommend the Board approve the amendment to Section R307-110-13, Section IX, Control Measures for Area and Point Sources, Part D, Ozone; Utah State Implementation Plan, Section IX.D.13.a, 2020 Uinta Basin Periodic Inventory Report and Section IX.D.13.b, 2023 Uinta Basin Periodic Inventory Report, for a 30-day public comment period.

⁵ Denial of Request for Attainment Date Extension, Finding of Failure to Attain, and Reclassification of an Area in Utah to Moderate for the 2015 Ozone National Ambient Air Quality Standard; 89 FR 101483; EPA-R08-OAR-2024-0001; FRL-12469-01-R8

⁶ Clean Air Act 181(a)(5); 40 CFR 51.1307

State of Utah
Administrative Rule Analysis
Revised May 2025

NOTICE OF SUBSTANTIVE CHANGE

TYPE OF FILING: Amendment

Rule or section number:

R307-110-13

Filing ID: OFFICE USE ONLY

Date of previous publication (only for CPRs):

Agency Information

1. Title catchline:	Environmental Quality, Air Quality	
Building:	Multi-Agency State Office Building	
Street address:	195 N 1950 W	
City, state:	Salt Lake City, UT	
Mailing address:	PO Box 144820	
City, state and zip:	Salt Lake City, UT 84114-4820	
Contact persons:		
Name:	Phone:	Email:
Sheila Vance	801-518-3132	svance@utah.gov
Jazmine Lopez	801-536-4050	jazminelopez@utah.gov

Please address questions regarding information on this notice to the persons listed above.

General Information

2. Rule or section catchline:	
R307-110-13. Section IX, Control Measures for Area and Point Sources, Part D, Ozone.	
3. Are any changes in this filing because of state legislative action?	Changes are not because of legislative action.
If yes, any bill number and session:	
4. Purpose of the new rule or reason for the change:	
The State of Utah is required to submit periodic emission inventories for marginal ozone nonattainment areas to the Environmental Protection Agency as part of the Clean Air Act (CAA) requirements (Section 182(a)(3)(A)). The first periodic emission inventory for the Uinta Basin nonattainment area (NAA) was completed and submitted for the year 2017. This amendment incorporates the periodic inventories for the years 2020 and 2023 into Utah's State Implementation Plan (SIP) and as such we are proposing to amend Section R307-110-13 Section IX, Control Measures for Area and Point Sources, Part D, Ozone to change the Board adoption date to the anticipated date of the amended plan.	
5. Summary of the new rule or change:	
This proposed rule amendment incorporates the required periodic emission inventory reports for the years 2020 and 2023 for the Uinta Basin NAA into the Utah SIP as required by the CAA. Pursuant to Section 182(a)(3) of the CAA, this inventory includes a comprehensive accounting of actual VOC and NOX emissions from the following source categories: point, area, on-road mobile, non-road mobile, and oil and gas sources. Section R307-110-13 Section IX, Control Measures for Area and Point Sources, Part D, Ozone is being amended to change the Board adoption date to the anticipated date of the amended plan.	

Fiscal Information

6. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:	
A. State budget:	
This rule change does not have any impact on the state budget as the change reflects work already completed by the Division of Air Quality as part of staff's required workload. This rule change does not alter current regulations or practices.	
B. Local governments:	
This rule change does not have any impact on local government budgets as this rule requires no action by local governments.	
C. Small businesses ("small business" means a business employing 1-49 persons):	
This rule change does not have any impact on small businesses as this rule requires no action by small businesses.	

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

This rule change does not have any impact on non-small businesses as this rule requires no action by 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 does not impact persons other than small businesses, non-small businesses, state or local government entities as this rule requires no action by persons other than small businesses, non-small businesses, state or local government entities.

F. Compliance costs for affected persons:

There are no compliance costs associated with this rule change, the change is editorial to incorporate already prepared reports into our SIP. This rule change does not alter current regulations or practices.

G. Regulatory Impact Summary Table (This table includes only fiscal impacts the agency was able to measure. If the agency could not estimate an impact, it is excluded from this table but described in boxes A through F.)

Regulatory Impact Summary Table					
Fiscal Cost	FY2026	FY2027	FY2028	FY2029	FY2030
State Budget	\$0	\$0	\$0	\$0	\$0
Local Governments	\$0	\$0	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0	\$0	\$0
Other Persons	\$0	\$0	\$0	\$0	\$0
Total Fiscal Cost	\$0	\$0	\$0	\$0	\$0
Fiscal Benefits	FY2026	FY2027	FY2028	FY2029	FY2030
State Budget	\$0	\$0	\$0	\$0	\$0
Local Governments	\$0	\$0	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0	\$0	\$0
Other Persons	\$0	\$0	\$0	\$0	\$0
Total Fiscal Benefits	\$0	\$0	\$0	\$0	\$0
Net Fiscal Benefits	\$0	\$0	\$0	\$0	\$0

H. Department head comments on fiscal impact and approval of regulatory impact analysis:

The Executive Director of the Department of Environmental Quality, Tim Davis, has reviewed and approved this regulatory impact 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:

Section 19-2-104	42 U.S.C. 85 Part D Section 7511a	

Incorporation by Reference Information

8. Incorporation by Reference (if this rule incorporates more than two items by reference, please include additional tables):

A. This rule adds or updates the following title of material incorporated by reference (a copy of the material incorporated by reference must be submitted to the Office of Administrative Rules. *If none, leave blank*):

Official Title of Materials Incorporated (from title page)	Utah State Implementation Plan Section IX, Control Measures for Area and Point Sources, Part D, Ozone.
Publisher	Division of Air Quality, Utah Department of Environmental Quality
Issue Date	July 1, 2026
Issue or Version	

B. This rule adds or updates the following title of material incorporated by reference (a copy of the material incorporated by reference must be submitted to the Office of Administrative Rules. *If none, leave blank*):

Official Title of Materials Incorporated (from title page)	
Publisher	
Issue Date	
Issue or Version	

Public Notice Information

9. The public may submit written or oral comments to the agency identified in box 1.

A. Comments will be accepted until: 05/15/2026

B. A public hearing (optional) will be held (The public may request a hearing by submitting a written request to the agency, as outlined in Section 63G-3-302 and Rule R15-1.):

Date:	Time (hh:mm AM/PM):	Place (physical address or URL):
05/13/2026	02:00PM - 03:00PM	A public hearing is set for May 13, 2026. Further details may be found below. The hearing will be cancelled should no request for one be made by May 11, 2026, at 10 AM MT. The final status of the public hearing will be posted on May 11, 2026, after 10 AM MT. The status of the public hearing may be checked at the following website location under the corresponding rule. https://deq.utah.gov/public-notices-archive/air-quality-rule-plan-changes-open-public-comment Interested Persons can participate in person or electronically, via the internet. In Person: MASOB 195 N. 1950 W. Salt Lake City, UT, 84116, First Floor, Air Quality Board Room Virtual Attendance: Time zone: America/Denver Google Meet joining info: Video call link: meet.google.com/brq-boro-amh Or dial: (US) +1 470-222-7694 PIN: 642 227 764#

To the agency: If more than one hearing is planned to take place, continue to add rows.

10. This rule change MAY become effective on: 07/01/2026

NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date.

Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 63G-3-302, 63G-3-303, and 63G-3-402. The office may return incomplete forms to the agency, 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, Division of Air Quality	Date:	03/10/2026
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R307. Environmental Quality, Air Quality.

R307-110. General Requirements: State Implementation Plan.

R307-110-13. Section IX, Control Measures for Area and Point Sources, Part D, Ozone.

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part D, Ozone, as most recently amended by the Utah Air Quality Board on ~~November 6, 2024~~ **July 1, 2026**, pursuant to Section 19-2-104, is incorporated by reference and made a part of Rule R307-110.

KEY: air pollution, PM10, PM2.5, ozone

Date of Last Change: ~~July 2, 2025~~ 2026

Notice of Continuation: December 1, 2021

Authorizing, and Implemented or Interpreted Law: 19-2-104

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UTAH STATE IMPLEMENTATION PLAN
**Section IX, Part D, Ozone; 2020 Uinta
Basin Periodic Inventory Report**
SECTION IX.D.13.a



Section IX.D.13.a 2020 Uinta Basin Marginal Ozone Periodic Inventory Report

IX.D.13.a.i Introduction

On October 26, 2015, the Environmental Protection Agency (EPA) promulgated revisions to the National Ambient Air Quality Standards (NAAQS) for ground-level ozone. EPA amended the primary and secondary ozone standards, lowering the threshold from 75 parts per billion (ppb) to 70 ppb, as determined by the three-year average of the annual fourth-highest daily eight-hour average concentration.¹ On August 3, 2018, EPA designated the Uinta Basin as a marginal ozone nonattainment area (NAA) based on the 2014-2016 design value and other relevant data.²

Ozone production is a year-round occurrence, though it is typically most prevalent during the summer months. However, under certain conditions, elevated ozone levels can also occur during the winter. The Uinta Basin is a rural region in northeastern Utah with a relatively small population, yet is a significant producer and transporter of crude oil. The Uinta Basin's unique geography and weather patterns combined with substantial emissions of volatile organic compounds (VOC) and oxides of nitrogen (NO_x) from oil and gas production leads to occasional episodes of elevated ozone levels. These ozone events typically occur during the winter months, when cold air inversions trap emissions within the basin. Under these conditions, snow-covered ground and sunlight provide the ultraviolet radiation and radiant energy necessary for VOCs and NO_x to react and form ozone.

Two years after the initial NAA designation, in August 2020, the Utah Division of Air Quality (the Division) submitted a 2017 base-year inventory reflecting a comprehensive, accurate, and current inventory of actual emissions from all sources as required by the Emission Inventory Requirements in 40 CFR 51.1315.³ EPA approved the 2017 inventory on August 5, 2021.⁴ Following the base-year inventory submission, the Division is required to compile a revised

¹ National Ambient Air Quality Standards for Ozone; 80 FR 65292; EPA-HQ-OAR-2008-0699, FRL-9933-18-OAR.

² Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards; 83 FR 25776; EPA-HQ-OAR-2017-0548; FRL-9977-72-OAR.

³ Emissions Inventory requirements, 40 CFR 51.1315, <https://www.ecfr.gov/current/title-40/section-51.1315>.

⁴ Approval and Promulgation of Implementation Plans; Utah; 2017 Base Year Inventories for the 2015 8-Hour Ozone National Ambient Air Quality Standard for the Uinta Basin, Northern Wasatch Front and Southern Wasatch Front Nonattainment Areas, 2021-14195 (86 FR 35404).

periodic inventory every 3-year period until the area is redesignated to attainment.⁵ This report fulfills the periodic inventory submission for 2020.

IX.D.13.a.ii Geographic and Nonattainment Area

The Uinta Basin lies in the northeast corner of Utah and is bound on the north by the Uinta Mountains, on the south by the Tavaputs Plateau, on the west by the Wasatch Range, and on the east by elevated terrain that separates it from Piceance Basin in Colorado. Duchesne and Uintah counties occupy most of the Basin, and the Uintah and Ouray Reservation covers a significant portion of basin lands.

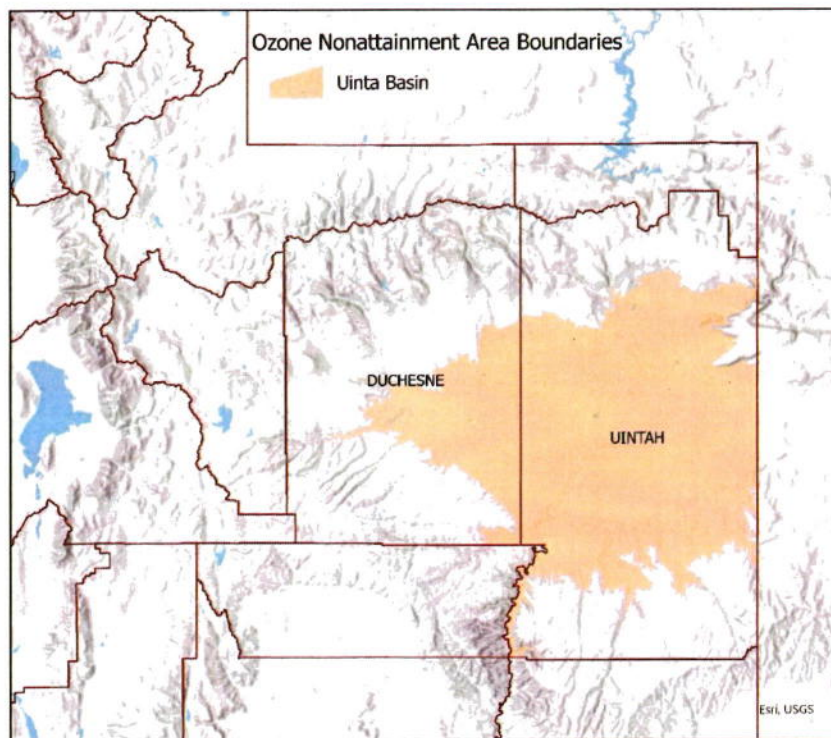


Figure 1: Uinta Basin Ozone Nonattainment Area Map

The marginal nonattainment designation applies to parts of Uintah and Duchesne Counties below a contiguous, external perimeter of 6,250-foot elevation. Energy production areas are scattered over federal, state, and tribal lands. The compliance and permitting jurisdiction varies depending

⁵ Ozone Plan Submission and Requirements, CAA Section 182(a)(3)(A).

on land ownership.

IX.D.13.a.iii Ozone Season Day Emissions and Temporal and Spatial Allocation

Periodic emissions inventories are required to be submitted in tons per day (TPD) for a typical weekday during the ozone season.⁶ In this case, it's a typical winter ozone Wednesday. Emissions are calculated for area and mobile sources on a county-by-county basis. The raw inventory data is entered into an emissions processing model and assigned a geographic location referred to as the grid cell. The point source emissions are assigned to their geographic location. To report emissions specific to the NAA, the Division uses a Geographic Information System description for each area to retrieve the respective emissions data after it has been gridded into the model.

The Division used 2020 National Emissions Inventory (NEI)⁷ data (except for the Oil and Gas sector) prepared by EPA and processed using Sparse Matrix Operator Kernel Emissions (SMOKE) v5.0 emissions processing software to prepare this inventory in order to normalize all emissions into TPD and to extract inventories specific to the NAA. The SMOKE model used the annual, county-wide emissions inventories from 2020 NEI and reformulated them for use in the air quality model. The reformulation includes temporal and spatial processing. Temporal processing converts emissions from annual to daily and hourly values. Spatial processing locates emissions from the county to specific grid cells within the modeling domain. Details of each source category processing for SMOKE run is included in the SMOKE Technical Support Document (TSD) attached to this submission.

IX.D.13.a.iv Emissions Inventory

Pursuant to Section 182(a)(3) of the Clean Air Act (CAA), this inventory includes a comprehensive accounting of actual VOC and NO_x emissions from the following source categories: point, area, on-road mobile, non-road mobile, and oil and gas sources. The inventoried pollutants include NO_x, VOCs, and carbon monoxide (CO). NO_x and VOCs are the

⁶ Emissions Inventory Requirements 40 CFR 51.1315(c), [https://www.ecfr.gov/current/title-40/part-51/section-51.1315#p-51.1315\(c\)](https://www.ecfr.gov/current/title-40/part-51/section-51.1315#p-51.1315(c)).

⁷ 2020 NEI data, <https://gaftp.epa.gov/Air/emismod/2020/2020emissions/>

only pollutants required by the implementation rule⁸, but CO is an important pollutant for modeling purposes and is therefore included in this inventory. This inventory represents emissions from state land only in the Uinta Basin NAA.

The Division does not include wildfire and biogenic emissions (emissions from natural sources such as vegetation) in the periodic emissions inventory submission because the inventory is limited to anthropogenic emissions and these source categories are neither required nor appropriate for inclusion under the Air Emissions Reporting Requirements (AERR). The Emissions Inventory Guidance Section 3.5.1 states, “Since the periodic inventory requirement in the CAA does not specify the degree of detail required for the periodic inventory, EPA has defined the necessary components through the AERR.”⁹

According to 40 CFR 51.15(b)(4) of the AERR, states are not required to report wildfire emissions¹⁰, as wildfires are considered natural or unpredictable events and are classified as “events” rather than emissions representative of a typical ozone work weekday. EPA develops national wildfire emissions inventories, and the Division lacks the year-specific meteorological modeling necessary to accurately temporalize wildfire emissions for the inventory year.

Additionally, the AERR was amended in 2008 to explicitly remove state reporting requirements for biogenic emissions¹¹, with EPA instead estimating these emissions using land-use and meteorological data. Biogenic emissions are highly dependent on year-specific meteorological conditions, and the Division has not conducted photochemical modeling for the inventory year. Available EPA biogenic and wildfire datasets are only provided at coarse spatial and temporal resolutions (county-level or 12-km grids and monthly averages), which are not compatible with the Division’s high-resolution, post-SMOKE inventory approach or its NAA-specific summaries for a typical ozone work weekday.

In 2020, oil and gas production activity in the Uinta Basin was drastically affected by the COVID-19 pandemic, which caused an unprecedented collapse in transportation demand and a corresponding crash in crude oil price. This market disruption led operators to substantially halt production and temporarily shut-in oil wells. Reduced activity associated with the oil and gas

⁸ Implementation of the 2015 National Ambient Air Quality Standards for Ozone: Nonattainment Area State Implementation Plan Requirements; 83 FR 62998; EPA-HQ-OAR-2016-0202, FRL-9986-53-OAR.

⁹ Emissions Inventory Guidance, https://www.epa.gov/sites/default/files/2016-12/documents/2016_ei_guidance_for_naaqs.pdf.

¹⁰ Wildfire Emissions Reporting, 40 CFR 51.15(b)(4), [https://www.ecfr.gov/current/title-40/part-51#p-51.15\(b\)\(4\)](https://www.ecfr.gov/current/title-40/part-51#p-51.15(b)(4)).

¹¹ Biogenic Emissions Reporting, <https://www.federalregister.gov/d/E8-29737/p-155>.

production resulted in a temporary drop in emissions in the basin. For this reason, 2020 represents an anomalous year driven by exceptional market and pandemic-related conditions and should not be used as a representative for typical production levels or emissions in the Uinta Basin. Additionally, the updated emissions factors and improved methodology that were developed since the 2017 base-year, were never retrospectively applied to update the 2020 inventory. For these reasons, only the 2020 inventory is reported with no comparison to the 2017 base year marginal inventory.

Table 1: 2020 Emissions Inventory in Ton Per Day for state Lands within the Uinta Basin NAA

	2020		
Sectors	NO _x	VOC	CO
Area Source	0.53	3.71	4.52
On-road Mobile	2.43	0.91	11.97
Non-road Mobile	0.20	0.16	2.24
Point Source	1.96	0.27	0.25
Oil & Gas	8.58	29.07	8.87
Total	13.70	34.13	27.85

IX.D.13.a.v Emissions Source Categories

1. Area Source

Area sources include emissions estimates for sources which individually are too small in magnitude to report as point sources. Significant examples include residential heating, commercial combustion, asphalt paving, and commercial and consumer solvent use. Area source emissions were calculated by county on a tons per year (TPY) basis using inputs provided in the

1 Wagon Wheel workbook “2020NEI_WW_SL_Input_Template_Submittals.xlsx”.¹² The Wagon
2 Wheel is an EPA tool developed in 2017 and updated in 2020 for the NEI reporting purposes.
3 Refer to the 2020 NEI TSD for nonpoint sources for specifics.¹³ Additionally, residential wood
4 combustion, livestock waste, and locomotive emissions are also included in the area source
5 inventory preparation. Respective TSDs are also included with this submittal.^{14 15 16 17}

7 2. Point Source

8
9 Point sources include emissions estimates for larger sources that are located at fixed, stationary
10 locations. Examples include large industrial facilities and electrical power plants. Point source
11 emissions are represented as the 2020 actual emissions from the source-reported numbers in the
12 Division’s State and Local Emissions Inventory System (SLEIS) database¹⁸. SLEIS contains
13 extensive quality assurance/ quality control guardrails that guide point sources as they submit
14 their data. Division staff then conduct another quality control check. This data is then reported to
15 EPA in preparation to build the NEI. Missing emissions values are gap-filled with EPA data
16 where available. The Division used the source-reported information from SLEIS to filter out
17 major point sources from the 2020 NEI in preparation for this marginal inventory.

18
19 Any source that has the potential to emit greater than or equal to 100 TPY of NO_x or VOC in
20 Utah is included in the point source inventory. There were four major point sources in the Uinta

¹² 2020 NEI Wagon Wheel Input Template,

https://gaftp.epa.gov/air/nei/2020/doc/supporting_data/nonpoint/Wagon%20Wheel%202020%20v7%20Final%20-%20SLT%20Inputs.zip.

¹³ 2020 National Emissions Inventory Technical Support Document: Nonpoint Overview,

www.epa.gov/system/files/documents/2023-03/NEI2020_TSD_Section6_Nonpoint_Overview.pdf.

¹⁴ 2020 National Emissions Inventory Technical Support Document: Fuel Combustion – Residential Heating - Wood,

www.epa.gov/system/files/documents/2023-03/NEI2020_TSD_Section27_RWC.pdf.

¹⁵ 2020 National Emissions Inventory Technical Support Document: Agriculture – Livestock Waste,

www.epa.gov/system/files/documents/2023-03/NEI2020_TSD_Section10_AgLivestockWaste.pdf.

¹⁶ 2020 National Emissions Inventory Technical Support Document: Locomotives,

www.epa.gov/system/files/documents/2023-03/NEI2020_TSD_Section12_Locomotives.pdf.

¹⁷ An error was made in the Solvent Controls Template, which was subsequently incorporated into the 2020 Wagon Wheel Workbook. Instead of 20,461.68 tons of statewide VOC emissions, only 13,184.02 tons were reported in the 2020 NEI, resulting in a difference of 7,277.66 tons. Utah notified EPA of this error and subsequently made corrections to the solvent sector. The Division used the updated dataset to prepare the 2020 periodic marginal inventory submission. Full data for all sectors, including the corrected solvent data, are available on the State of Utah 2020 Statewide Emissions Inventory page. At the time this inventory was prepared, the 2020 NEI database had not been updated.

¹⁸ Utah Division of Air Quality SLEIS, <https://sleis.deq.utah.gov/>.

Basin NAA in 2020, with one additional source added in 2023. These major point sources operate under approval orders issued by the Division that establish enforceable operating requirements and include source-specific conditions designed to limit and control emissions. A map of all major point sources in the Uinta Basin with grid cells overlaid on the NAA is provided in Figure 2. The 2020 statewide emissions inventories can be accessed at the Division's inventory webpage.¹⁹

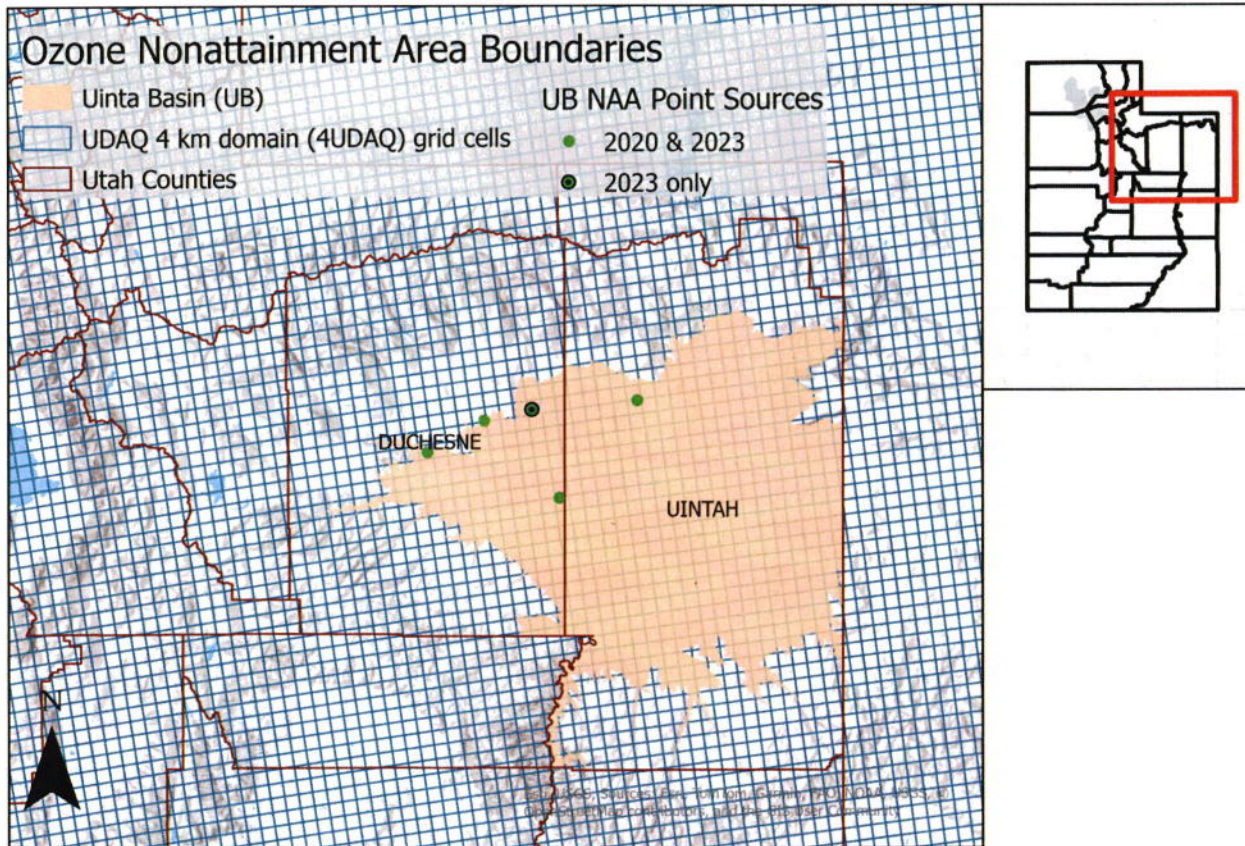


Figure 2: Map of the nonattainment area with an overlaid grid and the locations of point-source facilities

3. On-Road and Non-Road Mobile Sources

The mobile on-road sources include passenger vehicles, motorcycles, light-duty trucks, heavy-

¹⁹ 2020 Statewide Emissions Inventory, <https://deq.utah.gov/air-quality/2020statewide-emissions-inventories>.

duty trucks, and buses. Sources that are included under the non-road category are construction equipment, engines used in recreational activities, and portable industrial, commercial, and agricultural engines. Statewide emissions inventories were developed by EPA using an air quality modeling platform for air toxics and criteria air pollutants that represent the year 2020.²⁰ The platform is based on the 2020 NEI which was published in April 2023 along with other data specific to the year 2020 by running MOVES3.²¹ EPA uses default inputs to run the model if sufficient quality data is not available. The Division used the 2020 NEI data and processed it through SMOKE to calculate TPD emissions from the on-road and non-road mobile sector. Refer to the attached 2020 NEI TSD for on-road²² mobile sources and non-road²³ mobile sources for specific inventory preparation details.

4. Oil and Gas Sources

The 2020 NEI was not used to calculate emissions from the oil and gas sector. The NEI combines emissions from federal, state, and tribal lands, which would be difficult to separate and could result in inaccurate post-SMOKE emissions estimates for sources located on state land only.

Oil and gas source emissions are tabulated using a combination of the Division's individual inventory workbooks²⁴ submitted by oil and gas sources that provide throughputs and emissions as well as summations from data sources which include EPA/NOMAD (Nonpoint Methods Advisory group) oil and gas tool outputs. These emissions are reported to EPA via the Emissions Inventory System database. Missing emissions values are gap-filled with EPA data where available. Refer to the attached Oil and Gas TSD for specifics.

²⁰ Technical Support Document (TSD): Preparation of Emissions Inventories for the 2020 North American Emissions Modeling Platform,
www.epa.gov/system/files/documents/2024-10/2020_emismod_tsd_dec2023_508.pdf.

²¹ MOVES, www.epa.gov/moves.

²² 2020 National Emissions Inventory Technical Support Document: On-Road Mobile,
www.epa.gov/system/files/documents/2023-01/NEI2020_TSD_Section5_Onroad_0.pdf.

²³ 2020 National Emissions Inventory Technical Support Document: Nonroad Mobile Sources,
www.epa.gov/system/files/documents/2023-01/NEI2020_TSD_Section4_Nonroad.pdf.

²⁴ Oil and Gas Emissions Inventory Workbook,
<https://deq.utah.gov/air-quality/statewide-oil-gas-emissions-inventory>.

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UTAH STATE IMPLEMENTATION PLAN
**Section IX, Part D, Ozone; 2023 Uinta
Basin Periodic Inventory Report**

SECTION IX.D.13.b

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Section IX.D.13.b 2023 Uinta Basin Marginal Ozone Periodic Inventory Report

IX.D.13.b.i Introduction

On October 26, 2015, the Environmental Protection Agency (EPA) promulgated revisions to the National Ambient Air Quality Standards (NAAQS) for ground-level ozone. EPA amended the primary and secondary ozone standards, lowering the threshold from 75 parts per billion (ppb) to 70 ppb, as determined by the three-year average of the annual fourth-highest daily eight-hour average concentration.¹ On August 3, 2018, EPA designated the Uinta Basin as a marginal ozone nonattainment area (NAA) based on the 2014-2016 design value and other relevant data.²

Ozone production is a year-round occurrence, though it is typically most prevalent during the summer months. However, under certain conditions, elevated ozone levels can also occur during the winter. The Uinta Basin is a rural region in northeastern Utah with a relatively small population, yet is a significant producer and transporter of crude oil. The Uinta Basin's unique geography and weather patterns combined with substantial emissions of volatile organic compounds (VOC) and oxides of nitrogen (NO_x) from oil and gas production leads to occasional episodes of elevated ozone levels. These ozone events typically occur during the winter months, when cold air inversions trap emissions within the basin. Under these conditions, snow-covered ground and sunlight provide the ultraviolet radiation and radiant energy necessary for VOCs and NO_x to react and form ozone.

Two years after the initial NAA designation, in August 2020, the Utah Division of Air Quality (the Division) submitted a 2017 base-year inventory reflecting a comprehensive, accurate, and current inventory of actual emissions from all sources as required by the Emission Inventory Requirements in 40 CFR 51.1315.³ EPA approved the 2017 inventory on August 5, 2021.⁴ Following the base-year inventory submission, the Division is required to compile a revised

¹ National Ambient Air Quality Standards for Ozone; 80 FR 65292; EPA-HQ-OAR-2008-0699, FRL-9933-18-OAR.

² Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards; 83 FR 25776; EPA-HQ-OAR-2017-0548; FRL-9977-72-OAR.

³ Emissions Inventory requirements, 40 CFR 51.1315, <https://www.ecfr.gov/current/title-40/section-51.1315>.

⁴ Approval and Promulgation of Implementation Plans; Utah; 2017 Base Year Inventories for the 2015 8-Hour Ozone National Ambient Air Quality Standard for the Uinta Basin, Northern Wasatch Front and Southern Wasatch Front Nonattainment Areas, 2021-14195 (86 FR 35404).

periodic inventory every 3-year period until the area is redesignated to attainment.⁵ This report fulfills the periodic inventory submission for 2023.

IX.D.13.b.ii Geographic and Nonattainment Area

The Uinta Basin lies in the northeast corner of Utah and is bound on the north by the Uinta Mountains, on the south by the Tavaputs Plateau, on the west by the Wasatch Range, and on the east by elevated terrain that separates it from Piceance Basin in Colorado. Duchesne and Uintah counties occupy most of the Basin, and the Uintah and Ouray Reservation covers a significant portion of basin lands.

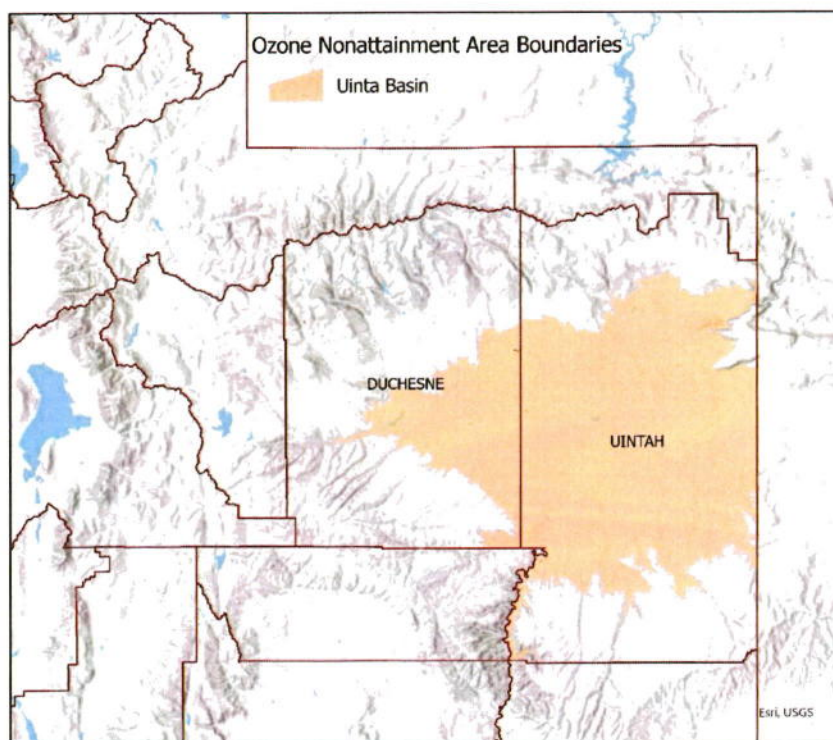


Figure 1: Uinta Basin Ozone Nonattainment Area Map

The marginal nonattainment designation applies to parts of Uintah and Duchesne Counties below a contiguous, external perimeter of 6,250-foot elevation. Energy production areas are scattered over federal, state, and tribal lands. The compliance and permitting jurisdiction varies depending on land ownership.

⁵ Ozone Plan Submission and Requirements, CAA Section 182(a)(3)(A).

IX.D.13.b.iii Ozone Season Day Emissions and Temporal and Spatial Allocation

Periodic emissions inventories are required to be submitted in tons per day (TPD) for a typical weekday during the ozone season.⁶ In this case, it's a typical winter ozone Wednesday. Emissions are calculated for area and mobile sources on a county-by-county basis. The raw inventory data is entered into an emissions processing model and assigned a geographic location referred to as the grid cell. The point source emissions are assigned to their geographic location. To report emissions specific to the NAA, the Division uses a Geographic Information System description for each area to retrieve the respective emissions data after it has been gridded into the model.

The Division prepared the source-specific inventories and processed using the Sparse Matrix Operator Kernel Emissions (SMOKE) v5.0 emissions processing software to prepare this inventory in order to normalize all emissions into TPD and to extract inventories specific to the NAA. SMOKE inventory reformulation includes temporal and spatial processing. Temporal processing converts emissions from annual to daily and hourly values. Spatial processing locates emissions from the county to specific grid cells within the modeling domain. Details of each source category processing for the SMOKE run is included in the SMOKE Technical Support Document (TSD) attached to this submission.

IX.D.13.b.iv Emissions Inventory

Pursuant to Section 182(a)(3) of the Clean Air Act (CAA), this inventory includes a comprehensive accounting of actual VOC and NO_x emissions from the following source categories: point, area, on-road mobile, non-road mobile, and oil and gas sources. The inventoried pollutants include NO_x, VOCs, and carbon monoxide (CO). NO_x and VOCs are the only pollutants required by the implementation rule⁷, but CO is an important pollutant for modeling purposes and is therefore included in this inventory. This inventory represents emissions from state land only in the Uinta Basin NAA.

The Division does not include wildfire and biogenic emissions (emissions from natural sources

⁶ Emissions Inventory Requirements 40 CFR 51.1315(c), [https://www.ecfr.gov/current/title-40/part-51/section-51.1315#p-51.1315\(c\)](https://www.ecfr.gov/current/title-40/part-51/section-51.1315#p-51.1315(c)).

⁷ Implementation of the 2015 National Ambient Air Quality Standards for Ozone: Nonattainment Area State Implementation Plan Requirements; 83 FR 62998; EPA-HQ-OAR-2016-0202, FRL-9986-53-OAR.

such as vegetation) in the periodic emissions inventory submission because the inventory is limited to anthropogenic emissions and these source categories are neither required nor appropriate for inclusion under the Air Emissions Reporting Requirements (AERR). The Emissions Inventory Guidance Section 3.5.1 states, “Since the periodic inventory requirement in the CAA does not specify the degree of detail required for the periodic inventory, EPA has defined the necessary components through the AERR.”⁸

According to 40 CFR 51.15(b)(4) of the AERR, states are not required to report wildfire emissions⁹, as wildfires are considered natural or unpredictable events and are classified as “events” rather than emissions representative of a typical ozone work weekday. EPA develops national wildfire emissions inventories, and the Division lacks the year-specific meteorological modeling necessary to accurately temporalize wildfire emissions for the inventory year.

Additionally, the AERR was amended in 2008 to explicitly remove state reporting requirements for biogenic emissions¹⁰, with EPA instead estimating these emissions using land-use and meteorological data. Biogenic emissions are highly dependent on year-specific meteorological conditions, and the Division has not conducted photochemical modeling for the inventory year. Available EPA biogenic and wildfire datasets are only provided at coarse spatial and temporal resolutions (county-level or 12-km grids and monthly averages), which are not compatible with the Division’s high-resolution, post-SMOKE inventory approach or its NAA-specific summaries for a typical ozone work weekday.

Comparing the periodic inventories for each 3-year period can be useful to understand emissions trends. As described in the periodic marginal emission inventory submitted for 2020 the values reported for that year are considered an anomaly due to impacts of the COVID-19 pandemic and an unusually high amount of oil and gas wells being shut-in due to decreased demand and falling prices.¹¹ Emission inventory methodology also changes as processes are improved, and makes direct year to year comparison difficult.

For this periodic inventory, Table 1 provides a comparison between the original 2017 periodic inventory that was approved by EPA, the updated 2017 inventory, and the 2023 periodic inventory to demonstrate a like-to-like comparison between 2017 and 2023. The formation of ozone in the Uinta Basin during wintertime is a unique phenomenon and as such many studies

⁸ Emissions Inventory Guidance, https://www.epa.gov/sites/default/files/2016-12/documents/2016_ei_guidance_for_naaqs.pdf.

⁹ Wildfire Emissions Reporting, 40 CFR 51.15(b)(4), [https://www.ecfr.gov/current/title-40/part-51#p-51.15\(b\)\(4\)](https://www.ecfr.gov/current/title-40/part-51#p-51.15(b)(4)).

¹⁰ Biogenic Emissions Reporting, <https://www.federalregister.gov/d/E8-29737/p-155>.

¹¹ Uinta Basin Periodic Marginal Inventory, 2020.

1 have been completed to better understand the chemistry of ozone formation and to increase the
2 accuracy of the emissions inventory. These updates were made to aid in potential photochemical
3 modeling and to develop effective regulatory strategies to reduce ozone precursor emissions. As
4 a result of these studies several updates to the 2017 oil and gas inventory were made since the
5 original 2017 periodic inventory was submitted.

6
7 The significant updates include adjustments made based upon the Uinta Basin VOC Composition
8 Study¹², Produced Water Disposal Facilities Emission Factors¹³ and the Uinta Basin Engine
9 Study.¹⁴ With these updates there was a significant increase in VOCs and CO and a decrease in
10 NOx from the original 2017 periodic inventory. The increase in VOCs was due to a more
11 accurate VOC emission factor that was applied to the oil and gas tank emissions and two-stroke
12 pump jack engines. The CO increase was due to a larger pumpjack engine emission factor. The
13 decrease in NOx was due to the engine study results.

14
15 When comparing the actual emissions numbers between 2017-updated and 2023, there are no
16 significant changes in the source categories except oil and gas, which is the largest source of
17 emissions in the basin. There are a reduction of VOCs and an increase in NOx and CO. The 33%
18 decrease in VOC emissions are most likely attributed to a decrease in two-stroke pump-jack
19 engines, increased oversight by compliance inspectors, and the fact that the majority of new
20 production in the Uinta Basin is accomplished with horizontal drilling technology that allows for
21 multiple well heads on a single location and requires stringent controls. NOx and CO are emitted
22 during fuel combustion. The small increase in NOx between 2017 and 2023 is likely attributable
23 to the larger engines or generators needed to support the increase in well completions for the
24 multi-well pads in 2023. While NOx increased slightly, CO decreased over the same period,
25 suggesting improved combustion efficiency. From an ozone formation perspective, NOx
26 increased slightly, and VOC decreased significantly, therefore ozone formation should be down.
27 It should be noted that the below periodic emission inventory numbers are for sources under state
28 jurisdiction in the Uinta Basin NAA only. It is challenging to make comparisons in emission
29 trends for the NAA absent the emission inventory numbers from sources under EPA and tribal
30 jurisdictions.

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¹² Uinta Basin VOC Composition Study Impacts on the 2017 Oil and Gas Emissions Inventory <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=386291&eqdocs=DAQ-2021-004302>.

¹³ Produced Water Disposal Facilities Emission Factors & Their Impact on the 2017 Oil and Gas Emissions Inventory <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=386288&eqdocs=DAQ-2020-016022>.

¹⁴ Uinta Basin Engine Study and Data Collection Impact on Emission Factors for the Oil and Gas Emission Inventory <https://lf-public.deq.utah.gov/WebLink/ElectronicFile.aspx?docid=648201&eqdocs=DAQ-2026-000439>.

Table 1: Emissions Inventory in Tons Per Day for State Lands within the Uinta Basin NAA:
2017 and 2023

	2017 Original			2017 Updated			2023		
Sectors	NOx	VOC	CO	NOx	VOC	CO	NOx	VOC	CO
Area Source	0.22	1.46	0.40	0.22	1.46	0.40	1.05	4.44	3.44
On-road Mobile	3.24	1.22	11.64	3.24	1.22	11.64	2.75	0.66	8.68
Non-road Mobile	0.10	0.11	1.47	0.10	0.11	1.47	0.20	0.40	2.97
Point Source	1.07	0.73	0.18	1.07	0.73	0.18	1.58	0.66	0.51
Oil & Gas	10.61	37.40	11.14	5.97	79.98	92.29	7.42	53.80	48.68
Total	15.23	41.03	24.91	10.60	83.50	105.98	13.02	59.95	64.28

IX.D.13.b.v Emissions Source Categories

1. Area Source

Area source emissions were calculated by county on a ton per year (TPY) basis using Division area source emissions calculation workbooks which serve as the basis for 2023 National Emissions Inventory data. Area sources are typically smaller, yet pervasive sources that do not qualify as point sources under the relevant emissions cutoffs. Area sources encompass more widespread sources that may be abundant, but that, individually, releases small amounts of a given pollutant. Notable examples include but are not limited to dry cleaners, residential heating and cooling, autobody painting, and commercial and consumer solvent use, and consumer products. Area source emissions are estimated as a group rather than individually using processes (i.e. fuel combustion) and activity data (including population, employment, VMT, fuel usage, animals, crops, oil and gas industry throughput submissions, etc.) to estimate emissions. Refer to

the attached TSD for specifics. The 2023 statewide emissions inventories can be accessed on the Division's inventory page.¹⁵

2. Point Source

Point sources include emissions estimates for larger sources that are located at fixed, stationary locations. Examples include large industrial facilities and electrical power plants. Point source emissions are represented as the actual 2023 emissions from the source-reported numbers in the Division's State and Local Emissions Inventory System (SLEIS) database.¹⁶ SLEIS contains extensive quality assurance/ quality control business rules that guide point sources as they submit their data. Division staff conduct additional quality assurance/quality control annually.

Any source that has the potential to emit greater than or equal to 100 TPY of NO_x or VOC in Utah is included in the point source inventory. There were four major point sources in the Uinta Basin NAA in 2020, with one additional source added in 2023. These major point sources operate under approval orders issued by the Division that establish enforceable operating requirements and include source-specific conditions designed to limit and control emissions. A map of all major point sources in the Uinta Basin with grid cells overlaid on the NAA is provided in Figure 2. Refer to the TSD attached with this document for specifics. The 2023 statewide emissions inventories can be accessed on the Division's inventory page.¹⁷

¹⁵ Statewide Emissions Inventory, <https://deq.utah.gov/air-quality/statewide-emissions-inventories>.

¹⁶ Utah Division of Air Quality SLEIS, <https://sleis.deq.utah.gov/>.

¹⁷ Statewide Emissions Inventory, <https://deq.utah.gov/air-quality/statewide-emissions-inventories>.

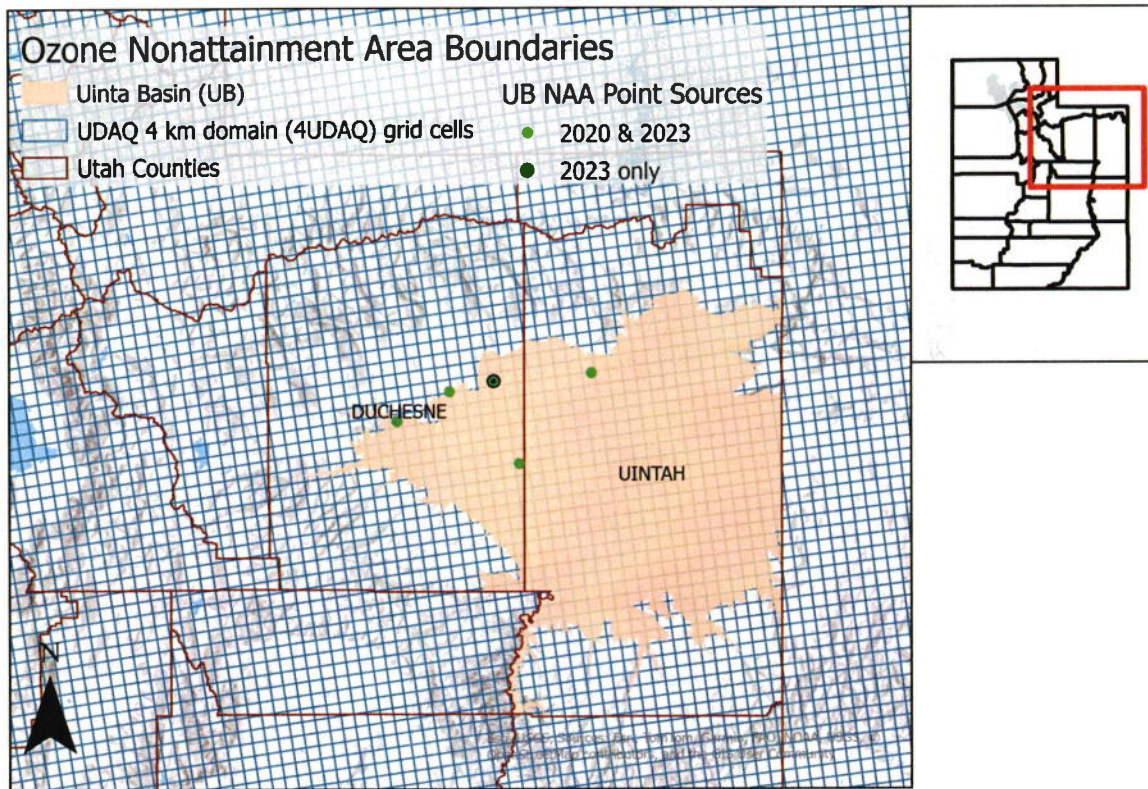


Figure 2: Map of the nonattainment area with an overlaid grid and the locations of point-source facilities

3. On-Road Mobile Source

On-road mobile sources include emissions from motorized vehicles that normally operate on public roadways. This includes passenger cars, motorcycles, minivans, sport-utility vehicles, light-duty trucks, heavy-duty trucks, and buses. On-road emissions were prepared using EPA approved MOVES3 (Motor Vehicle Emission Simulator).¹⁸ This model produces emissions daily estimates for on-road vehicles by providing emissions profiles for starts, exhaust, evaporative, and hot soak conditions.

The 2023 on-road mobile inventory projection was originally prepared as a requirement for the Moderate Ozone SIP¹⁹ before MOVES4 was available for use. The Division used the 2017 base-year inventory to project the 2023 emissions. The work was done in conjunction with the Utah

¹⁸ MOVES, www.epa.gov/moves.

¹⁹ Northern Wasatch Front Moderate Ozone SIP, <https://deq.utah.gov/air-quality/northern-wasatch-front-moderate-ozone-sip-technical-support-documentation>.

Department of Transportation to develop the Uinta Basin on-road mobile inventory. The inventory was developed in TPD for an average winter weekday for the NAA in the Uinta Basin. Refer to the attached TSD with this document for model specific inputs.

4. Non-Road Mobile Source

Non-road mobile sources include planes, trains, yard care equipment, construction equipment, engines used in recreational activities, and portable industrial, commercial, and agricultural engines. The 2023 non-road mobile inventory projection was originally prepared as a requirement for the Moderate Ozone SIP.²⁰ The Division used the 2017 base-year inventory to project the 2023 emissions by using EPA's MOVES4-Nonroad model²¹. Refer to the TSD attached with this document for model specific inputs.

5. Oil and Gas Source

Oil and gas source emissions are tabulated using a combination of the Division's individual inventory workbooks²² submitted by oil and gas sources located on state land that provide throughputs and emissions as well as summations from data sources which include EPA/NOMAD (Nonpoint Methods Advisory group) oil and gas tool outputs. These emissions are reported to EPA via the Emissions Inventory System database. Missing emissions values are gap-filled with EPA data where available. Refer to the Oil and Gas TSD attached with this document for specifics.

²⁰ Northern Wasatch Front Moderate Ozone SIP, <https://deq.utah.gov/air-quality/northern-wasatch-front-moderate-ozone-sip-technical-support-documentation>.

²¹ MOVES, www.epa.gov/moves.

²² Oil and Gas Emissions Inventory Workbook, <https://deq.utah.gov/air-quality/statewide-oil-gas-emissions-inventory>.

ITEM 7

Air Toxics



State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQA-078-26

MEMORANDUM

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: February 5, 2026

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – January 2026

Asbestos Demolition/Renovation NESHAP Inspections	17
Asbestos AHERA Inspections	2
Asbestos State Rules Only Inspections	14
Asbestos Notification Forms Accepted	164
Asbestos Telephone Calls	239
Asbestos Individuals Certifications Approved	66
Asbestos Company Certifications	9
Asbestos Alternate Work Practices Approved	8
Lead-Based Paint (LBP) Inspections	3
LBP Notification Forms Approved	3
LBP Telephone Calls	39
LBP Letters Prepared and Mailed	0
LBP Courses Reviewed/Approved	0
LBP Course Audits	0
LBP Individual Certifications Approved	8
LBP Firm Certifications	9

Notices of Violation Sent	0
Compliance Advisories Sent	10
Warning Letters Sent	4
Settlement Agreements Finalized	3
Penalties Agreed to:	
RJM Restoration Corporation/Michael Thompson	\$1,650.00
Kastle Rock Excavation and Development, LLC/Layne Kap	\$312.50
Leading Tech Development-Construction/Mike MacFarlane	<u>\$1,000.00</u>
Total:	\$2,962.50



State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQA-137-26

MEMORANDUM

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: March 4, 2026

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – February 2026

Asbestos Demolition/Renovation NESHAP Inspections	8
Asbestos AHERA Inspections	0
Asbestos State Rules Only Inspections	12
Asbestos Notification Forms Accepted	140
Asbestos Telephone Calls	264
Asbestos Individuals Certifications Approved	104
Asbestos Company Certifications	11
Asbestos Alternate Work Practices Approved	6
Lead-Based Paint (LBP) Inspections	1
LBP Notification Forms Approved	1
LBP Telephone Calls	68
LBP Letters Prepared and Mailed	1
LBP Courses Reviewed/Approved	0
LBP Course Audits	0
LBP Individual Certifications Approved	58
LBP Firm Certifications	8

Notices of Violation Sent	0
Compliance Advisories Sent	6
Warning Letters Sent	8
Settlement Agreements Finalized	3

Penalties Agreed to:

Park City School District/Todd Hansen	\$400.00
Cripple Creek Consulting & Environmental/Tucker Jay Smith	\$2,025.00
Asbestos Abatement of Utah/John Hoskins	<u>\$2,025.00</u>
Total:	\$4,450.00

Compliance



State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQC-140-26

MEMORANDUM

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: February 5, 2026

SUBJECT: Compliance Activities – January 2026

ACTIVITIES:

Activity	Monthly Total
Inspections	76
On-Site Stack Test & CEM Audits	0
Stack Test & RATA Report Reviews	24
Emission Report Reviews	21
Temporary Relocation Request Reviews	5
Fugitive Dust Control Plan Reviews	101
Soil Remediation Report Reviews	0
Open Burn Permits Issued	267
Miscellaneous Inspections ¹	38
Complaints Received	29
Wood Burning Complaints Received	14
Breakdown Reports Received	1
Compliance Actions Resulting from a Breakdown	0
VOC Inspections (Gas station vapor recovery)	0
Warning Letters Issued	1
Notices of Violation Issued	0
Compliance Advisories Issued	16
No Further Action Letters Issued	1
Settlement Agreements Reached	2
Penalties Assessed	\$4,605

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

SETTLEMENT AGREEMENTS:

Party	Amount
Uinta Wax Operating, LLC	\$3,287
Parowan Rock Products	\$1,318

UNRESOLVED NOTICES OF VIOLATION:

Party	Date Issued
Citation Oil and Gas (in administrative litigation)	01/15/2020
Uinta Wax Operating (formerly CH4 Finley)	07/24/2020
Finley Resources	09/15/2022
Holcim/Amrize	12/19/2023
Holcim/Amrize	03/27/2024
Holcim/Amrize	08/02/2024
CKC Operations, LLC	02/18/2025
Bedrock Sand & Gravel	05/21/2025
Ash Grove Cement (2)	10/30/2025
CUR Henry Mountains Uranium (Tony M Mine)	11/20/2025



State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQC-265-26

MEMORANDUM

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: March 4, 2026

SUBJECT: Compliance Activities – February 2026

ACTIVITIES:

Activity	Monthly Total
Inspections	83
On-Site Stack Test & CEM Audits	8
Stack Test & RATA Report Reviews	87
Emission Report Reviews	34
Temporary Relocation Request Reviews	8
Fugitive Dust Control Plan Reviews	106
Soil Remediation Report Reviews	1
Open Burn Permits Issued	375
Miscellaneous Inspections ¹	40
Complaints Received	18
Wood Burning Complaints Received	2
Breakdown Reports Received	0
Compliance Actions Resulting from a Breakdown	0
VOC Inspections (Gas station vapor recovery)	0
Warning Letters Issued	3
Notices of Violation Issued	0
Compliance Advisories Issued	13
No Further Action Letters Issued	1
Settlement Agreements Reached	1
Penalties Assessed	\$807

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

SETTLEMENT AGREEMENTS:

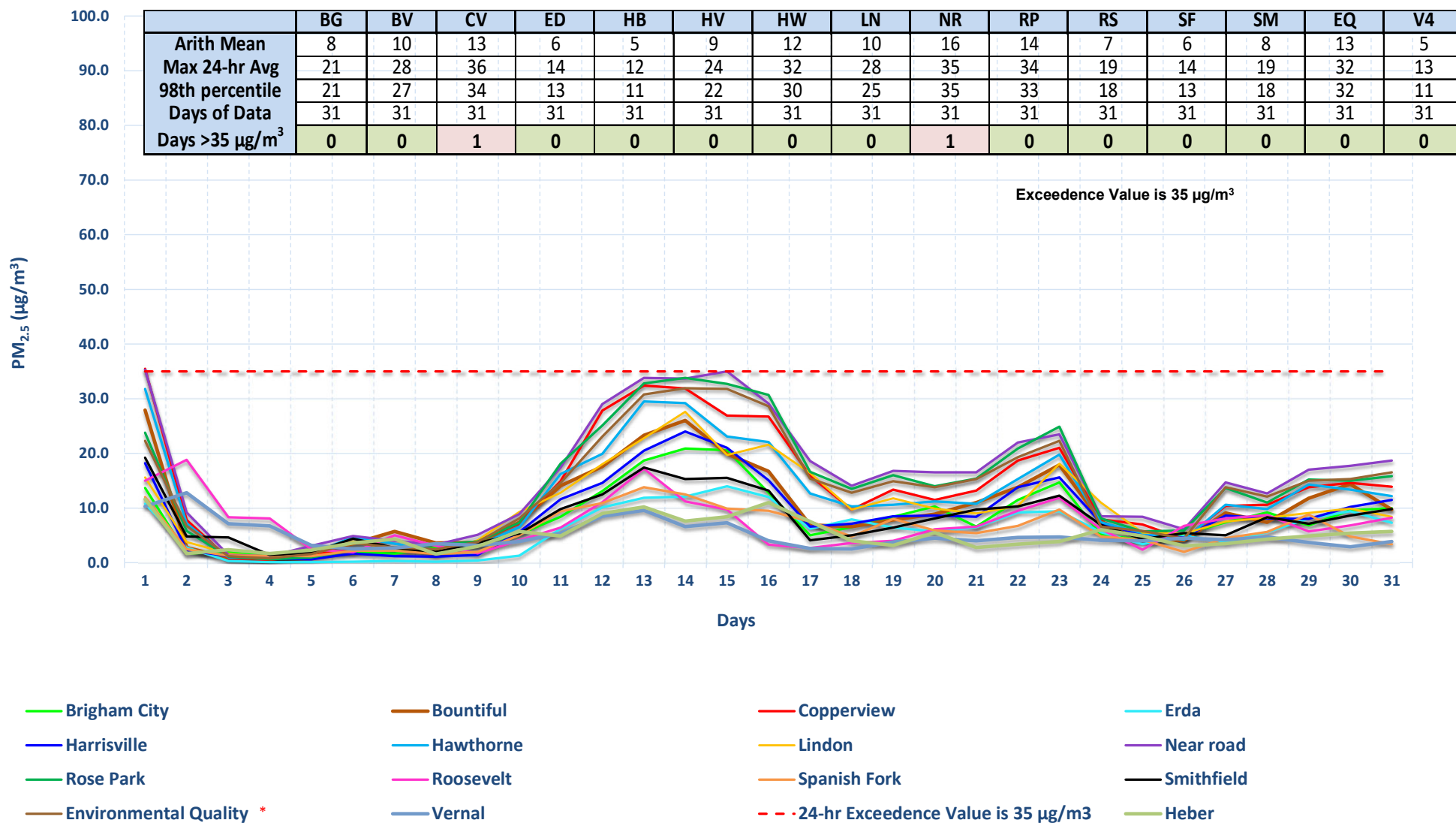
Party	Amount
Witt Excavating	\$807

UNRESOLVED NOTICES OF VIOLATION:

Party	Date Issued
Citation Oil and Gas (in administrative litigation)	01/15/2020
Uinta Wax Operating (formerly CH4 Finley)	07/24/2020
Finley Resources	09/15/2022
Holcim/Amrize	12/19/2023
Holcim/Amrize	03/27/2024
Holcim/Amrize	08/02/2024
CKC Operations, LLC	02/18/2025
Bedrock Sand & Gravel	05/21/2025
Ash Grove Cement (2)	10/30/2025
CUR Henry Mountains Uranium (Tony M Mine)	11/20/2025

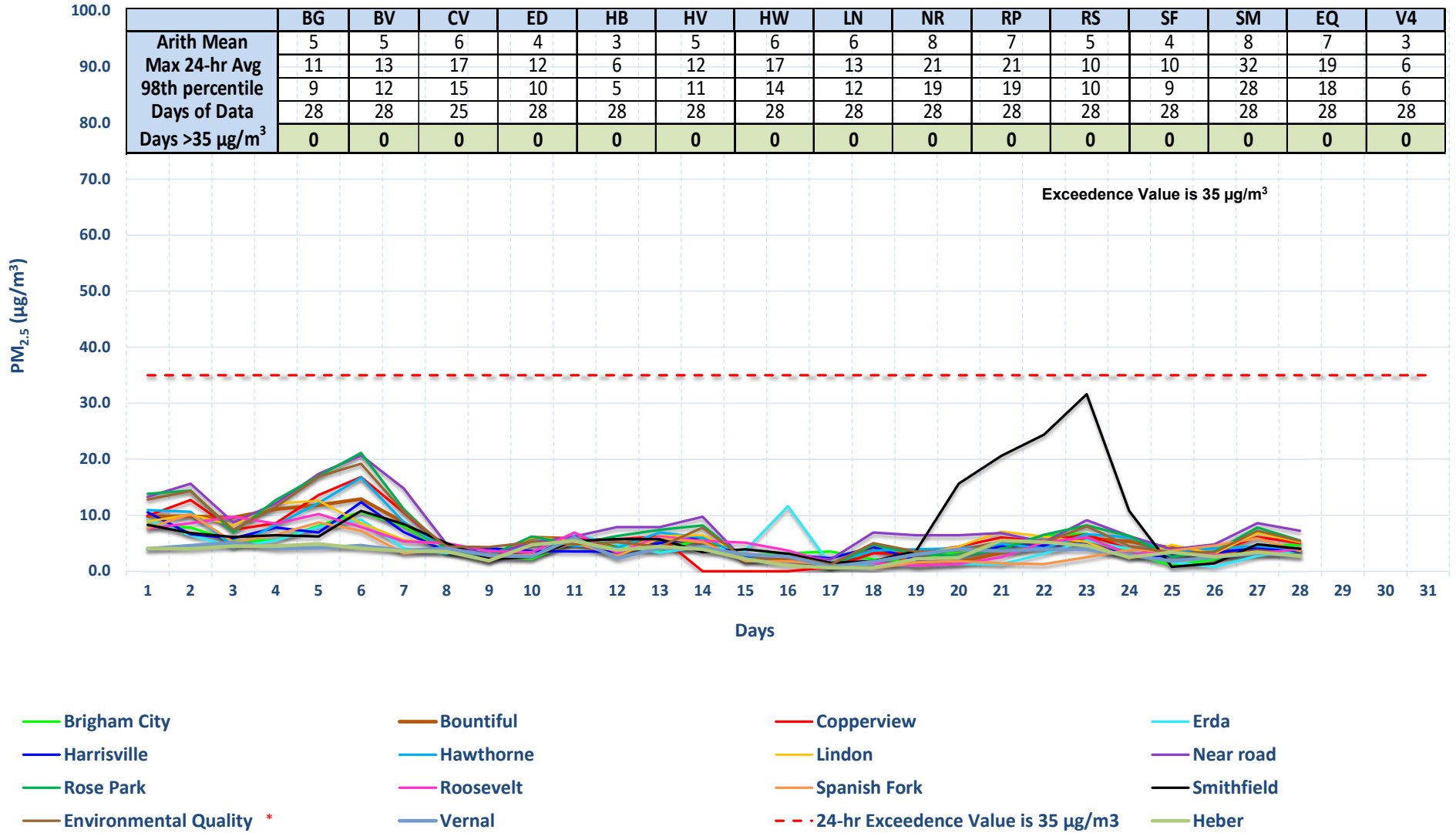
Monitoring

Utah 24-Hr PM_{2.5} Data January 2026



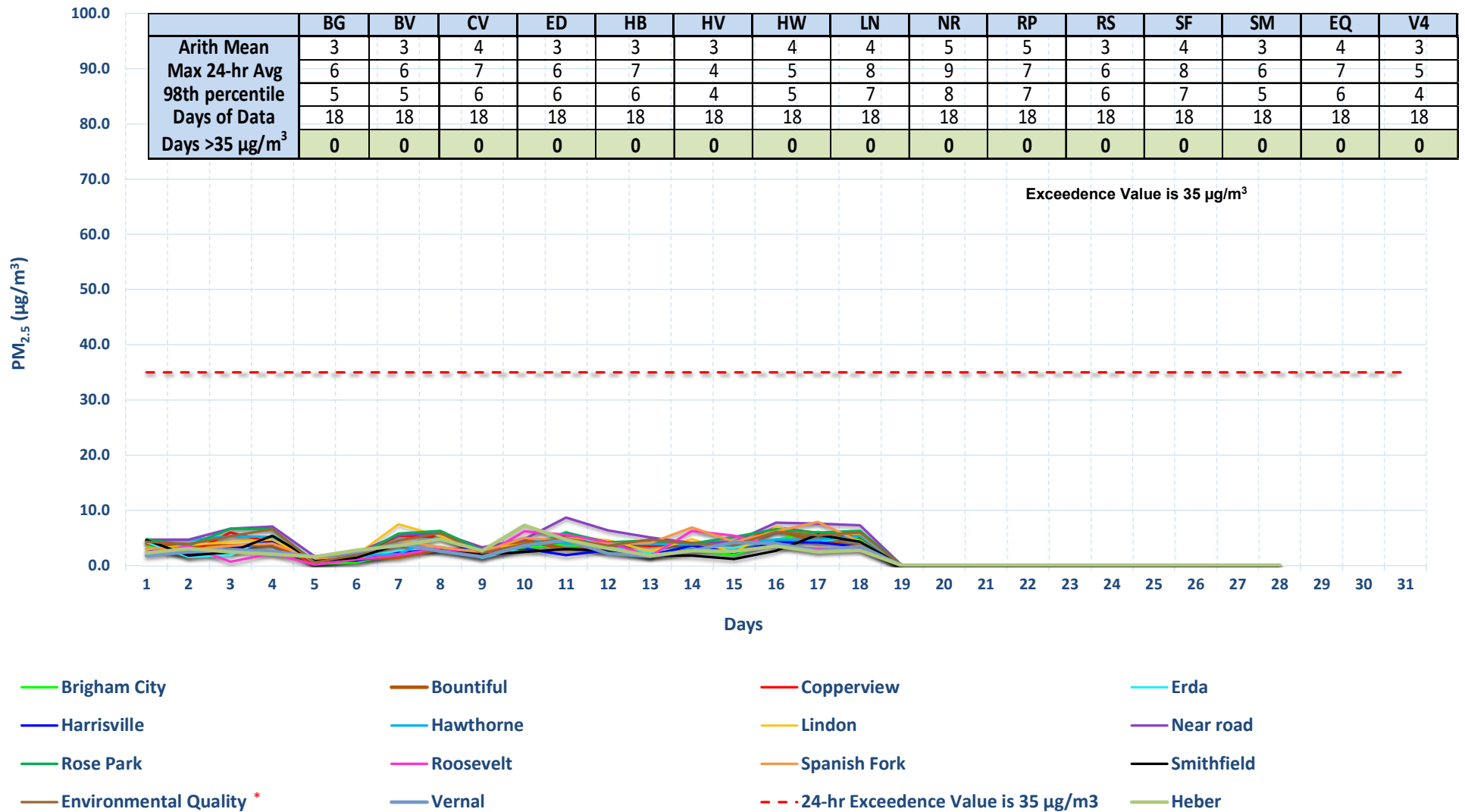
* Environmental Quality (EQ) previously named Technical Support Center (TSC)

Utah 24-Hr PM_{2.5} Data February 2026



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

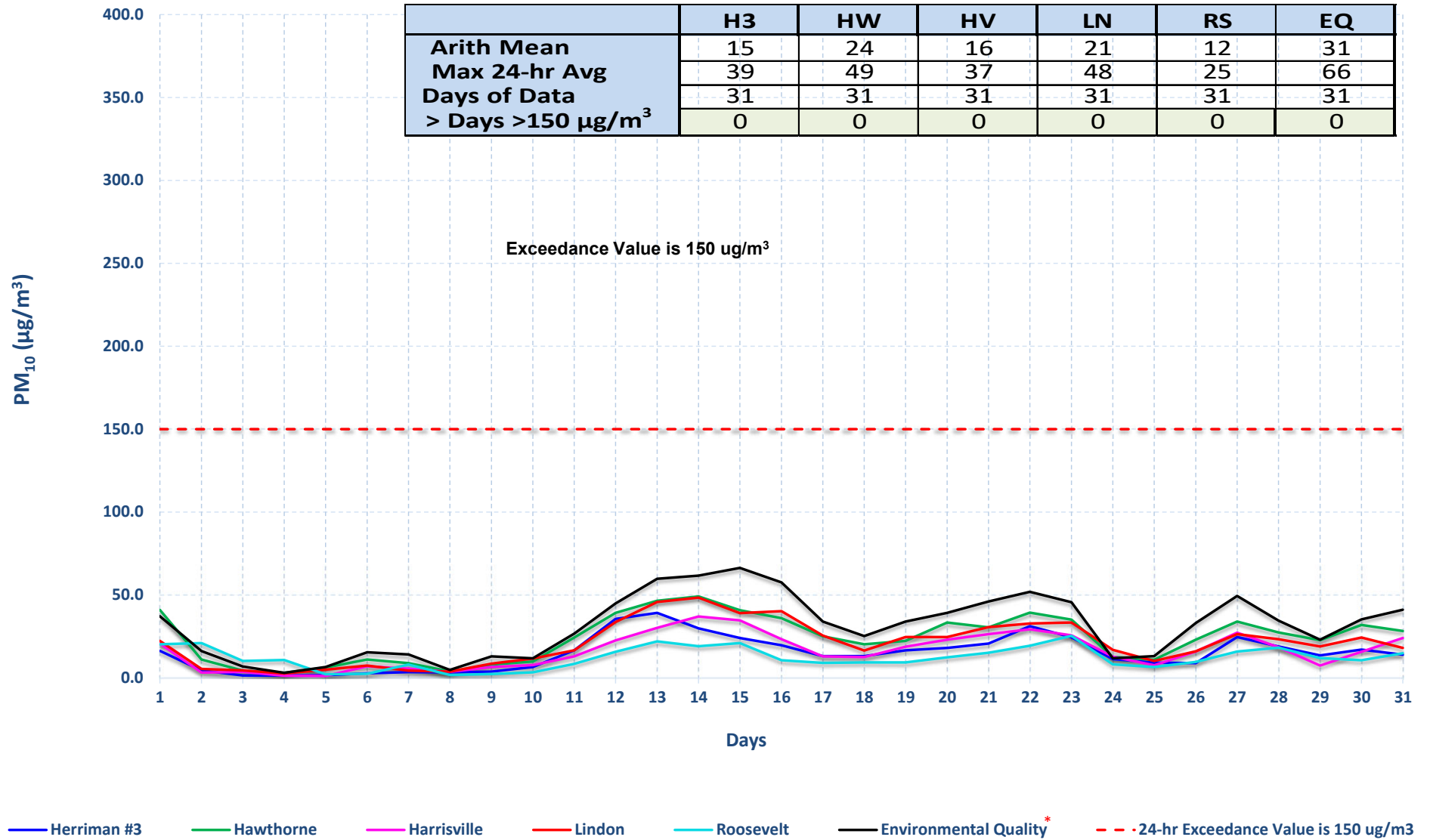
Utah 24-Hr PM_{2.5} Data March 2026



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

Utah 24-hr PM₁₀ Data January 2026

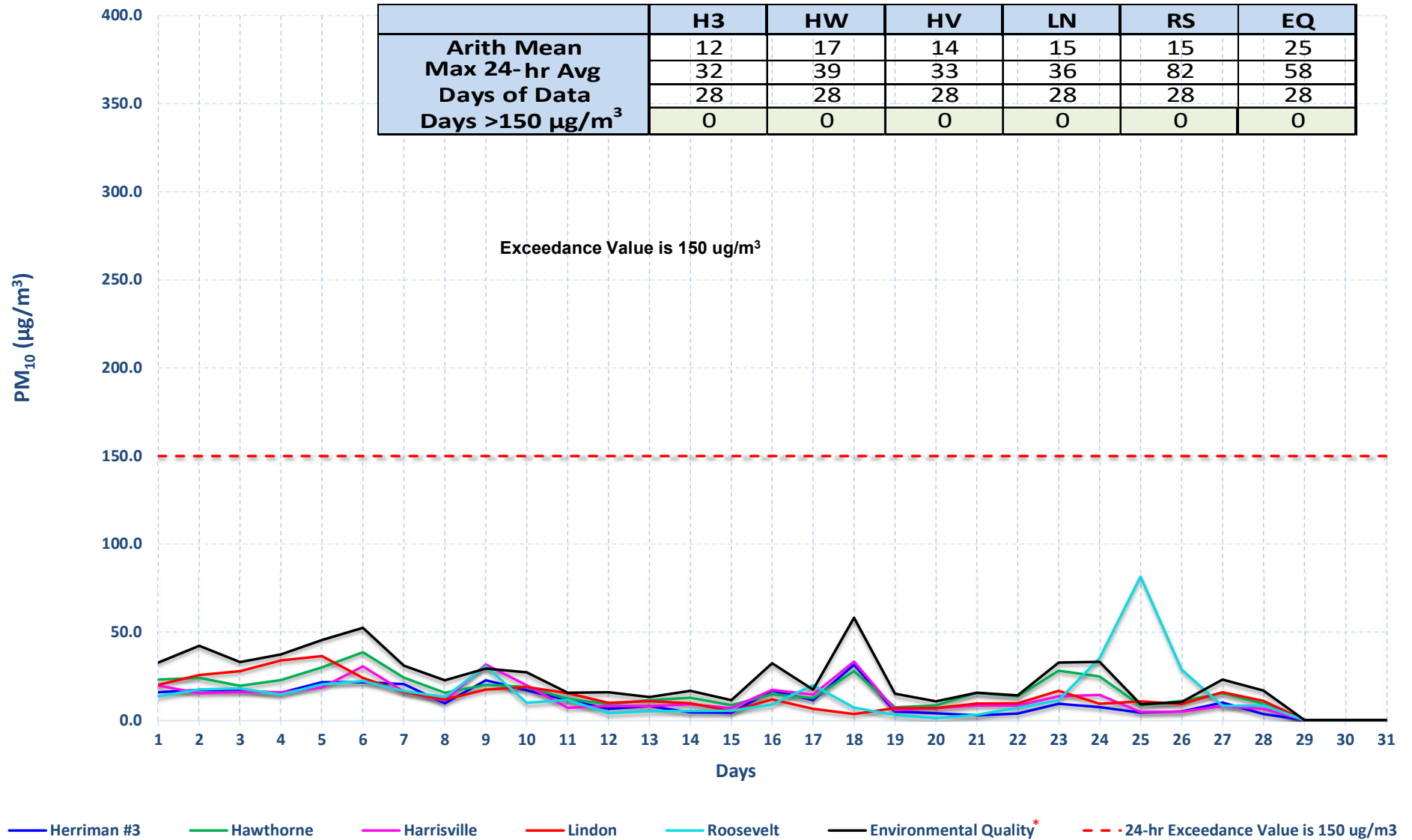
	H3	HW	HV	LN	RS	EQ
Arith Mean	15	24	16	21	12	31
Max 24-hr Avg	39	49	37	48	25	66
Days of Data	31	31	31	31	31	31
> Days >150 µg/m ³	0	0	0	0	0	0



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

Utah 24-hr PM₁₀ Data February 2026

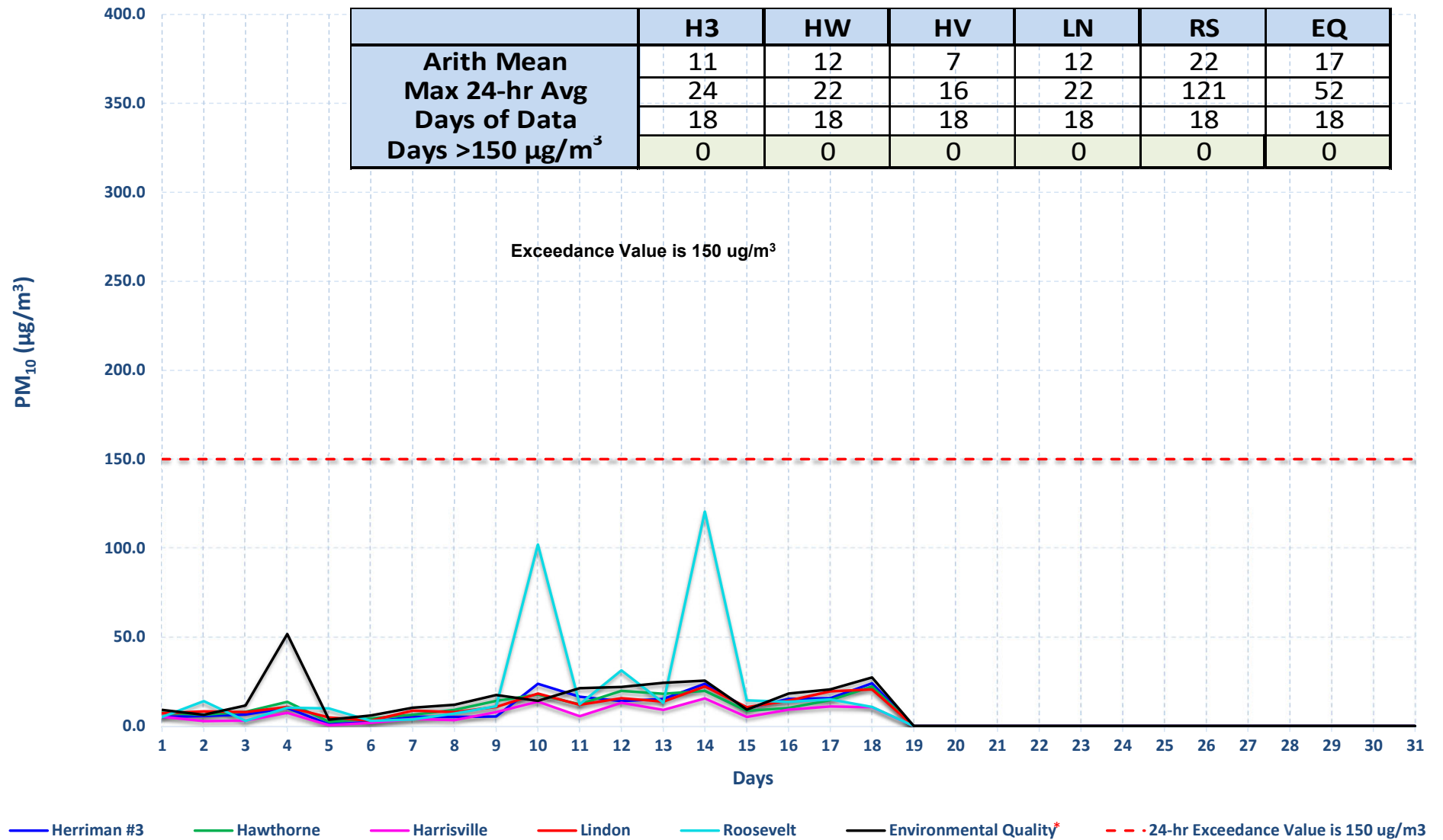
	H3	HW	HV	LN	RS	EQ
Arith Mean	12	17	14	15	15	25
Max 24-hr Avg	32	39	33	36	82	58
Days of Data	28	28	28	28	28	28
Days >150 µg/m ³	0	0	0	0	0	0



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

Utah 24-hr PM₁₀ Data March 2026

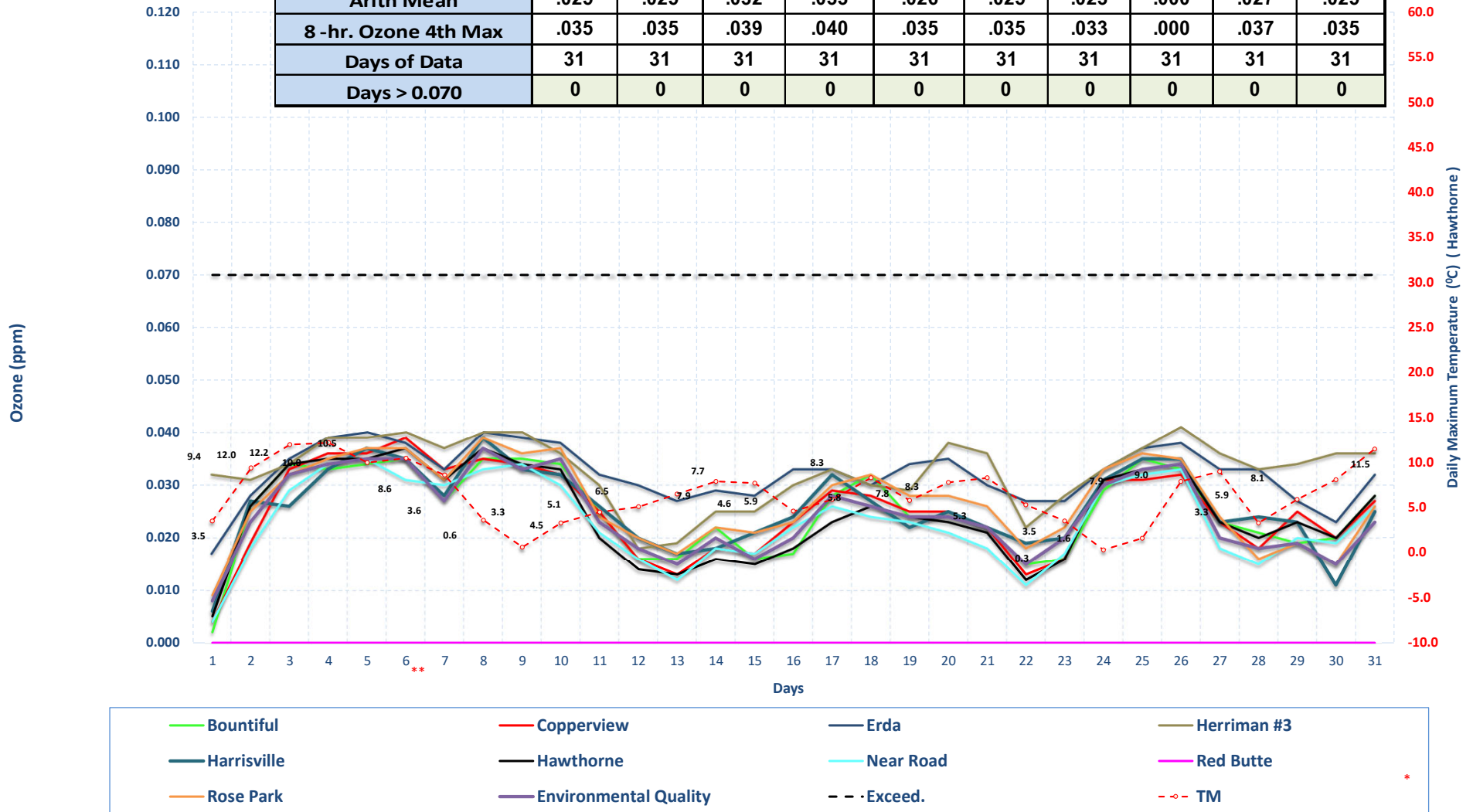
	H3	HW	HV	LN	RS	EQ
Arith Mean	11	12	7	12	22	17
Max 24-hr Avg	24	22	16	22	121	52
Days of Data	18	18	18	18	18	18
Days >150 µg/m ³	0	0	0	0	0	0



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

Highest 8-hr Ozone Concentration & Daily Maximum Temperature January 2026

O3 Jan 2026	BV	CV	ED	H3	HV	HW	NR	RB	RP	EQ
Arith Mean	.025	.025	.032	.033	.026	.025	.023	.000	.027	.025
8-hr. Ozone 4th Max	.035	.035	.039	.040	.035	.035	.033	.000	.037	.035
Days of Data	31	31	31	31	31	31	31	31	31	31
Days > 0.070	0	0	0	0	0	0	0	0	0	0

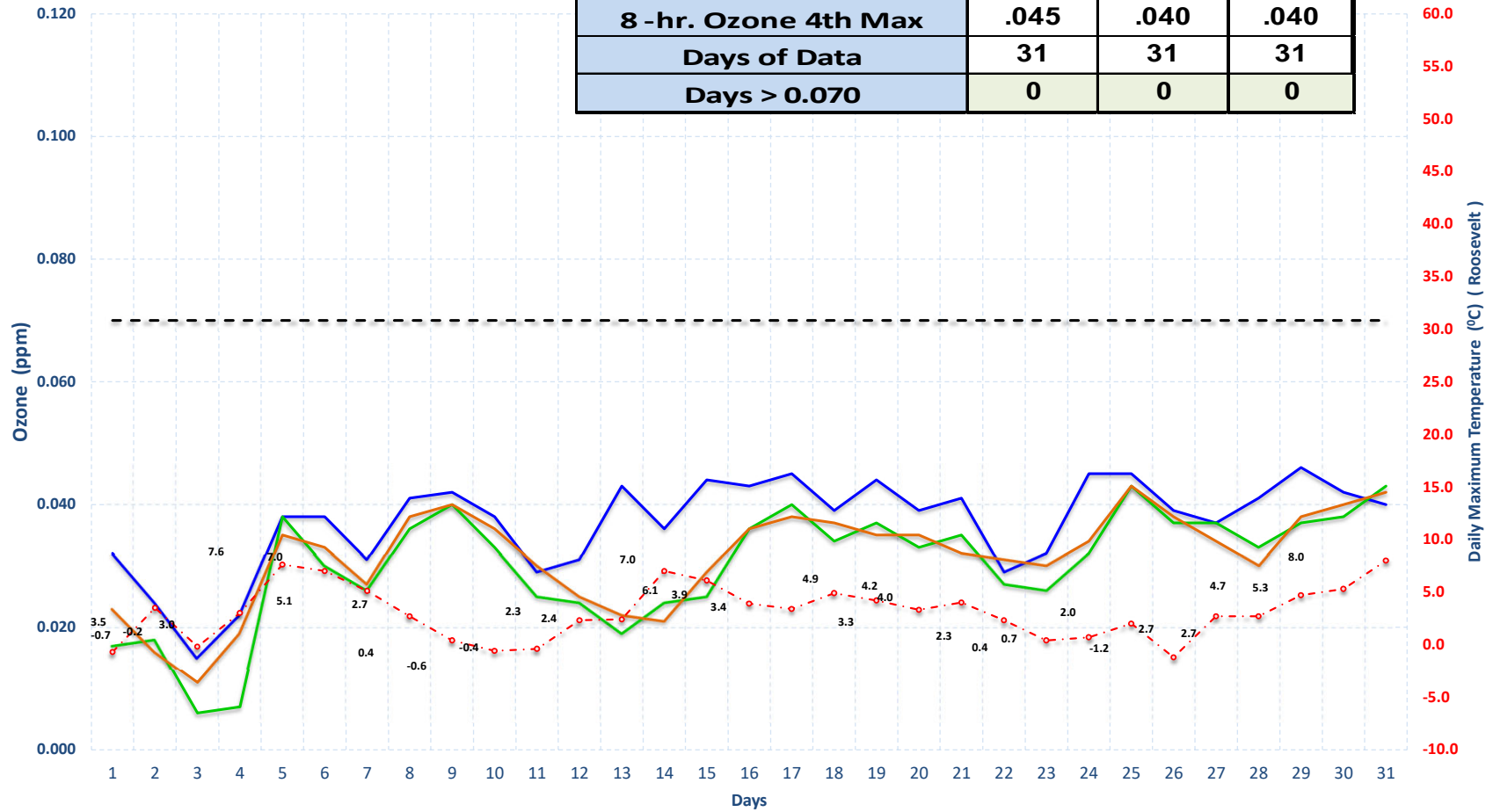


* Environmental Quality (EQ) previously named Technical Support Center (TSC)

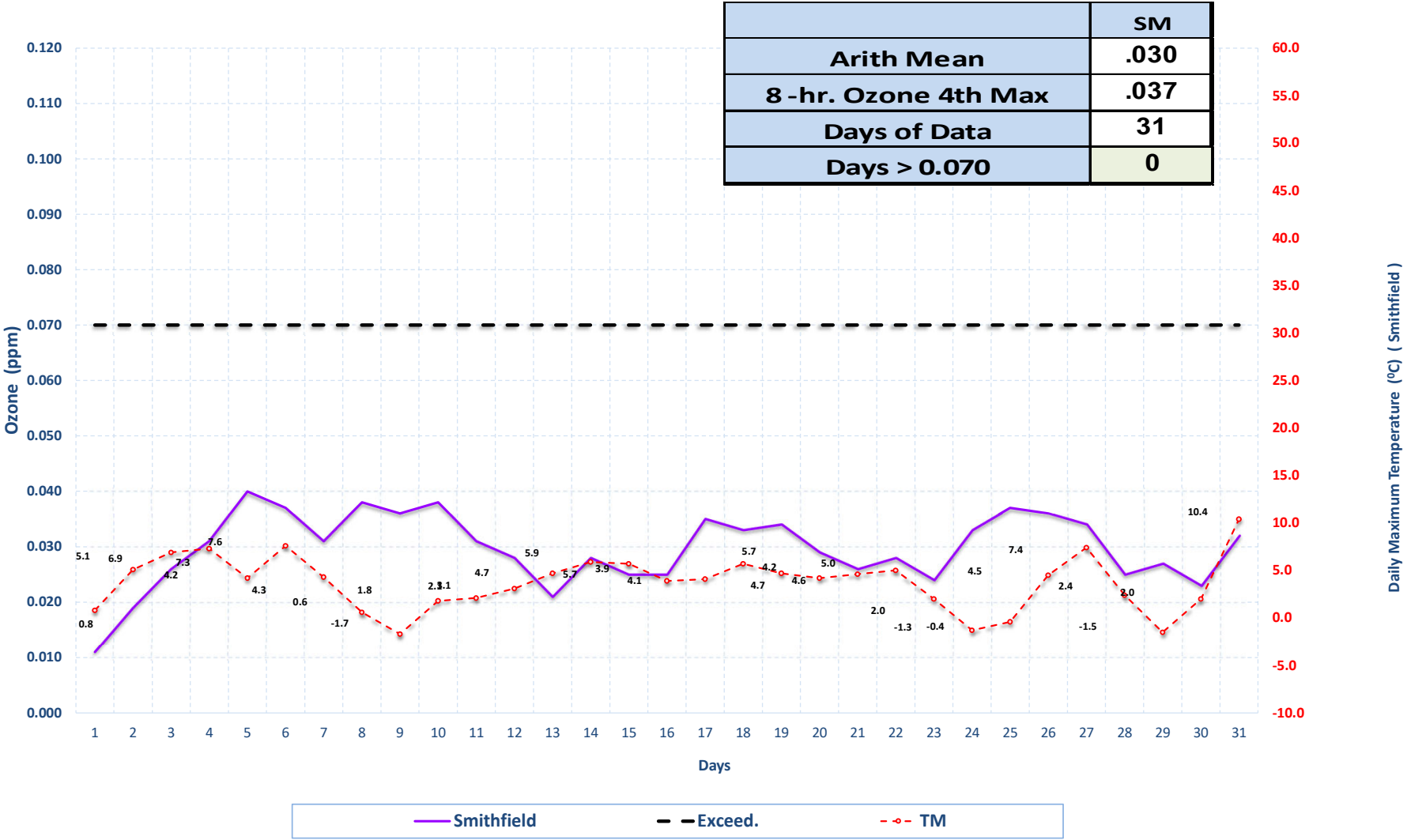
** Controlling Monitor

Highest 8-hr Ozone Concentration & Daily Maximum Temperature January 2026

	P2	RS	V4
Arith Mean	.037	.030	.032
8 -hr. Ozone 4th Max	.045	.040	.040
Days of Data	31	31	31
Days > 0.070	0	0	0

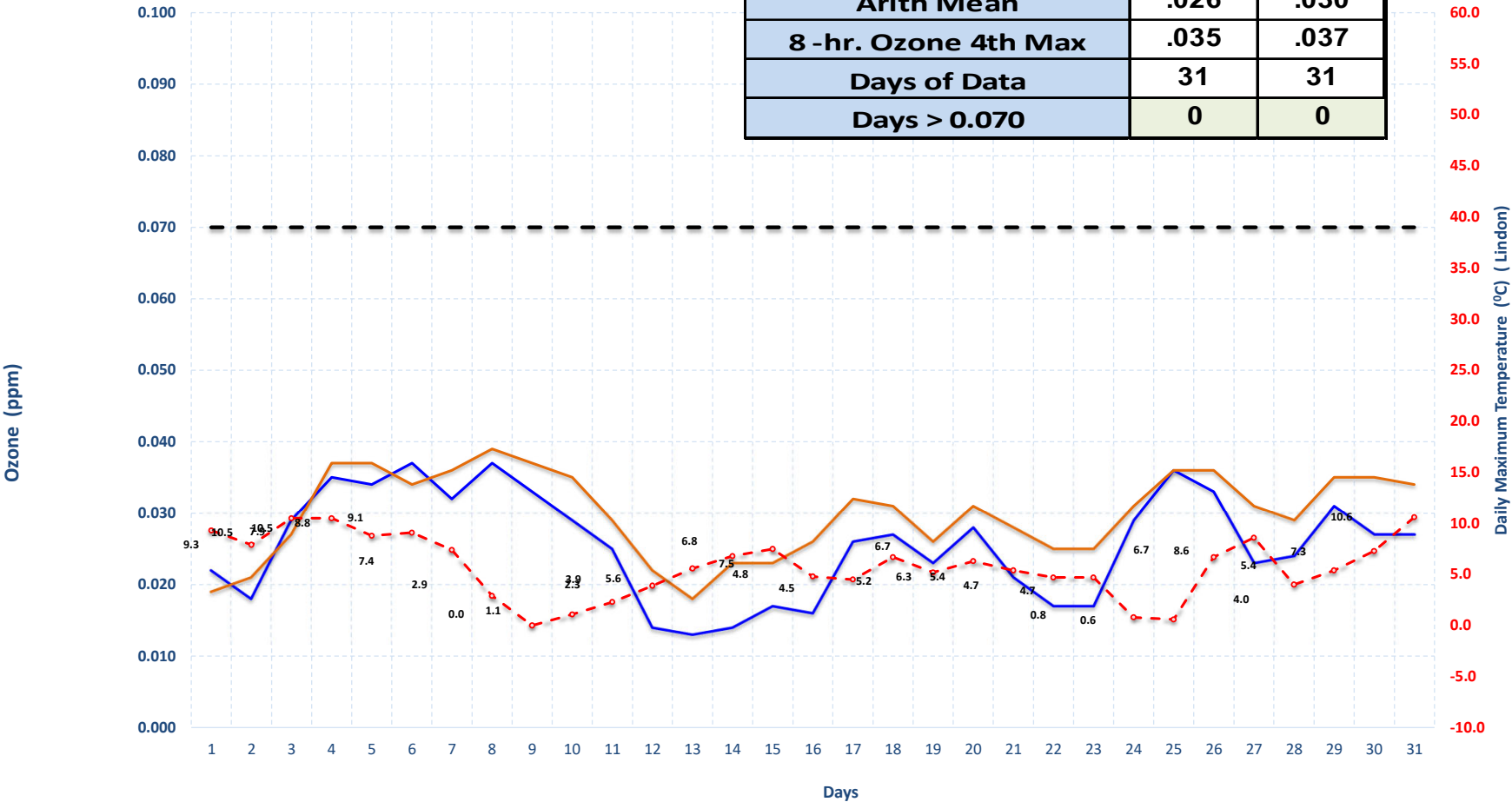


Highest 8-hr Ozone Concentration & Daily Maximum Temperature January 2026



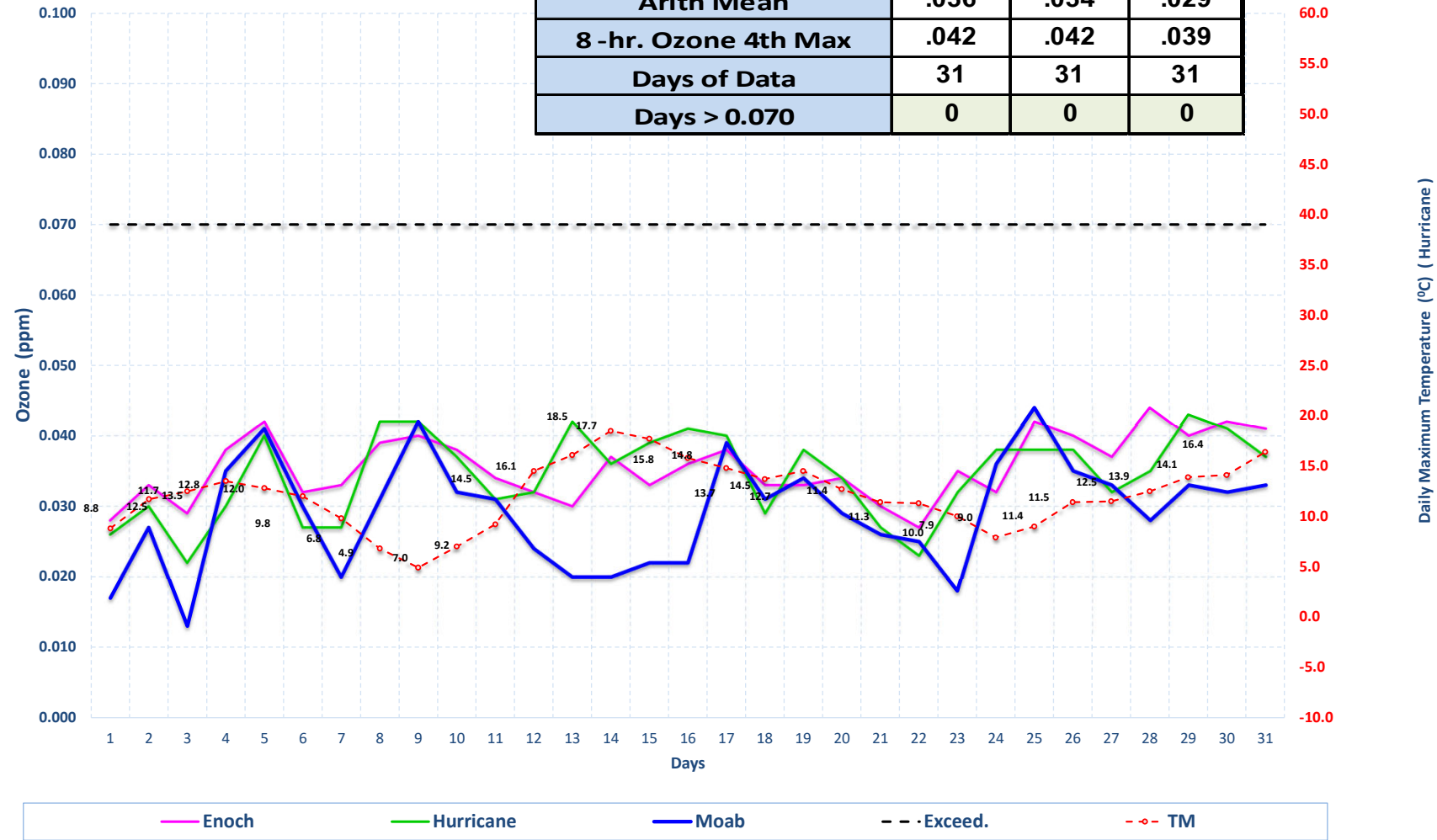
Highest 8-hr Ozone Concentration & Daily Maximum Temperature January 2026

	LN	SF
Arith Mean	.026	.030
8 -hr. Ozone 4th Max	.035	.037
Days of Data	31	31
Days > 0.070	0	0

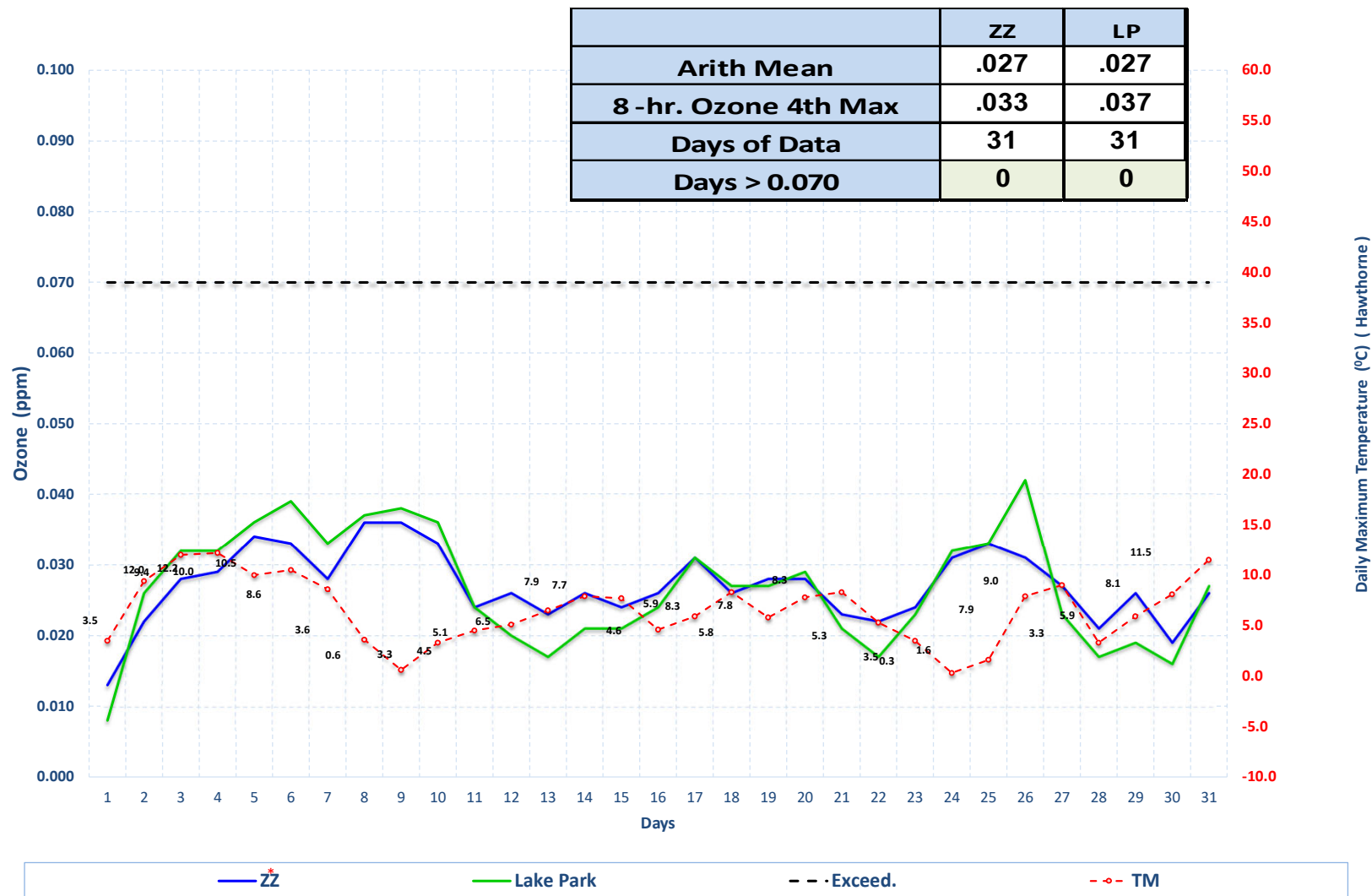


Highest 8-hr Ozone Concentration & Daily Maximum Temperature January 2026

	EN	HC	M7
Arith Mean	.036	.034	.029
8 -hr. Ozone 4th Max	.042	.042	.039
Days of Data	31	31	31
Days > 0.070	0	0	0



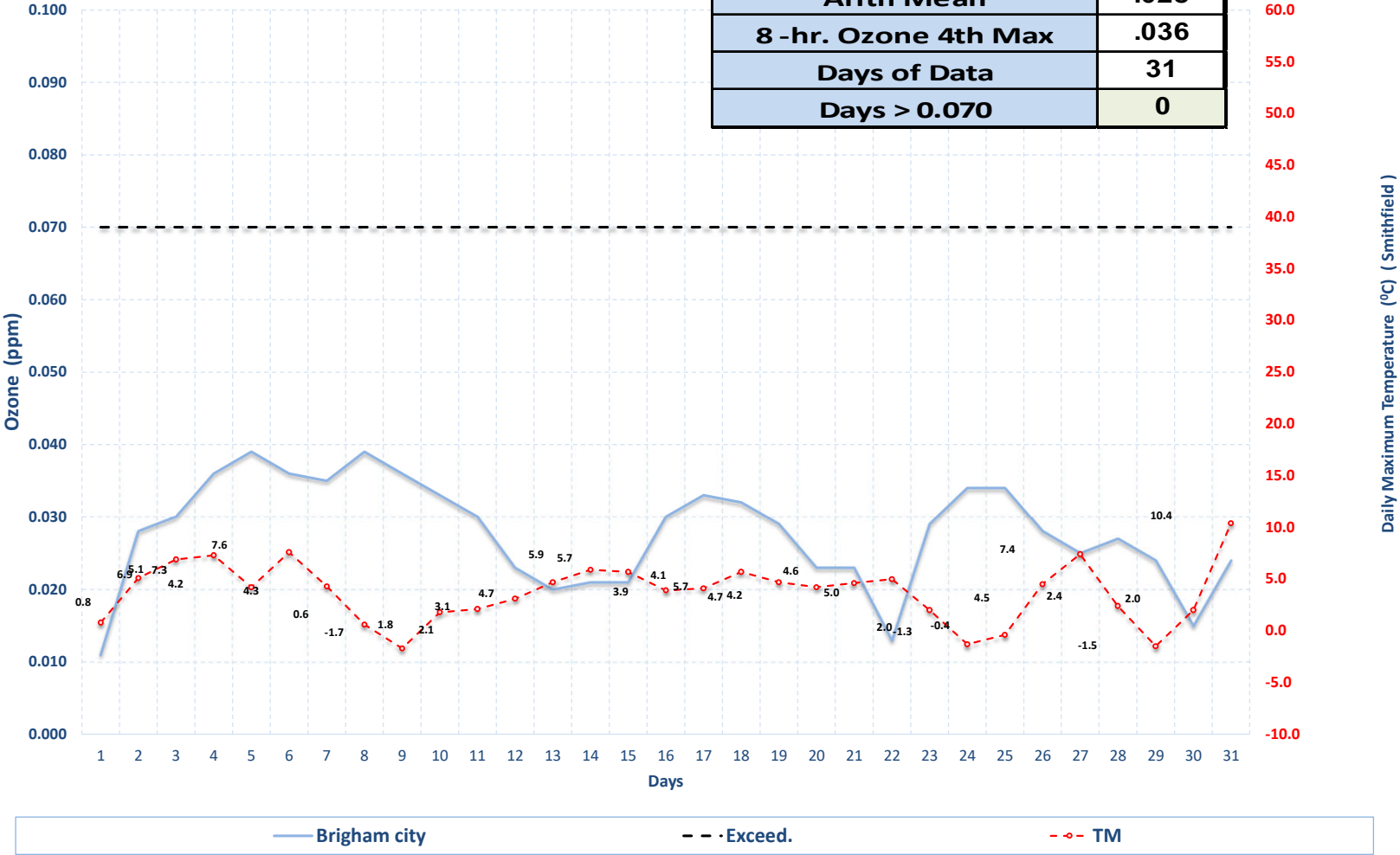
Highest 8-hr Ozone Concentration & Daily Maximum Temperature January 2026 Stations Monitoring the Inland Port Development



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

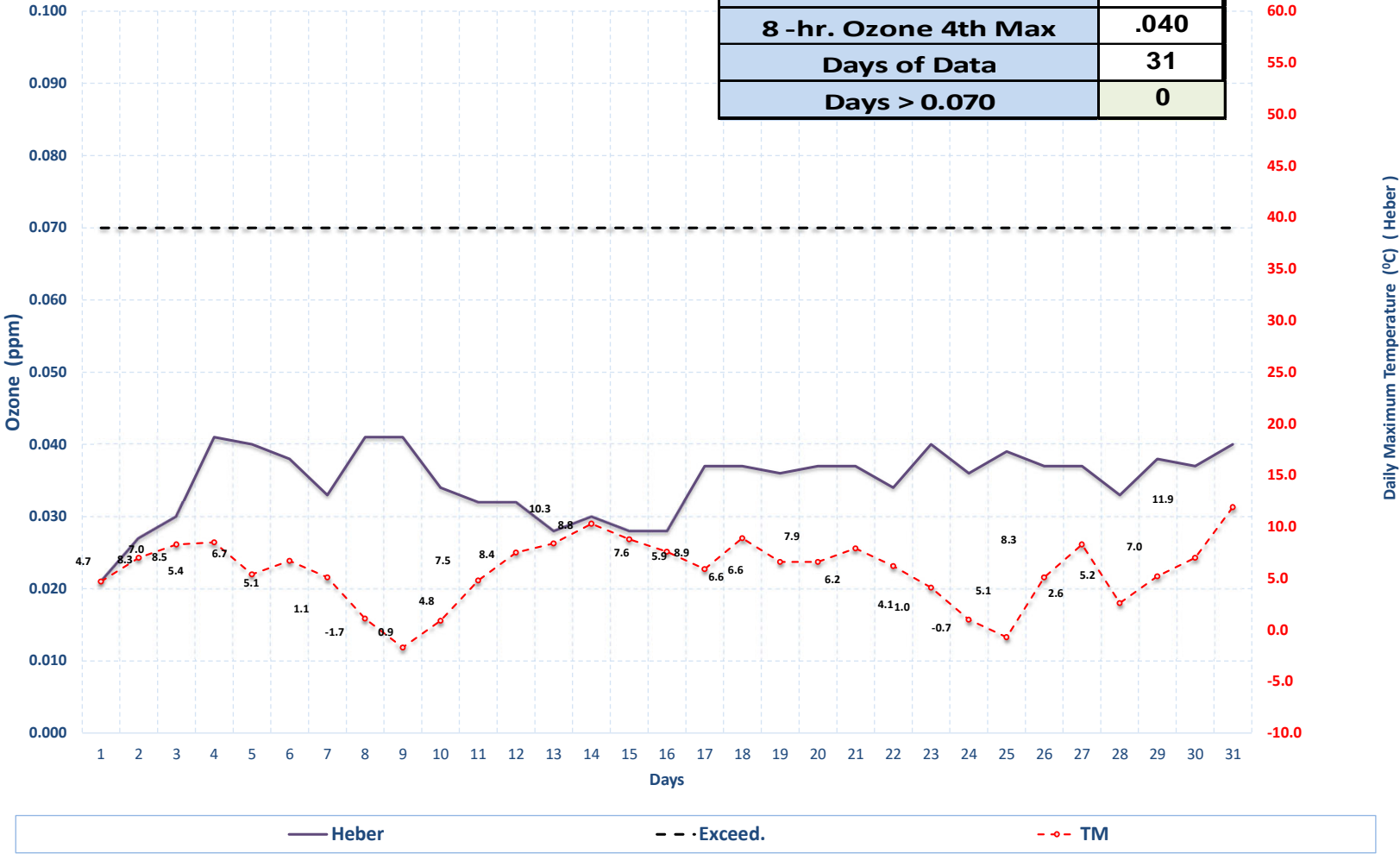
Highest 8-hr Ozone Concentration & Daily Maximum Temperature January 2026

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



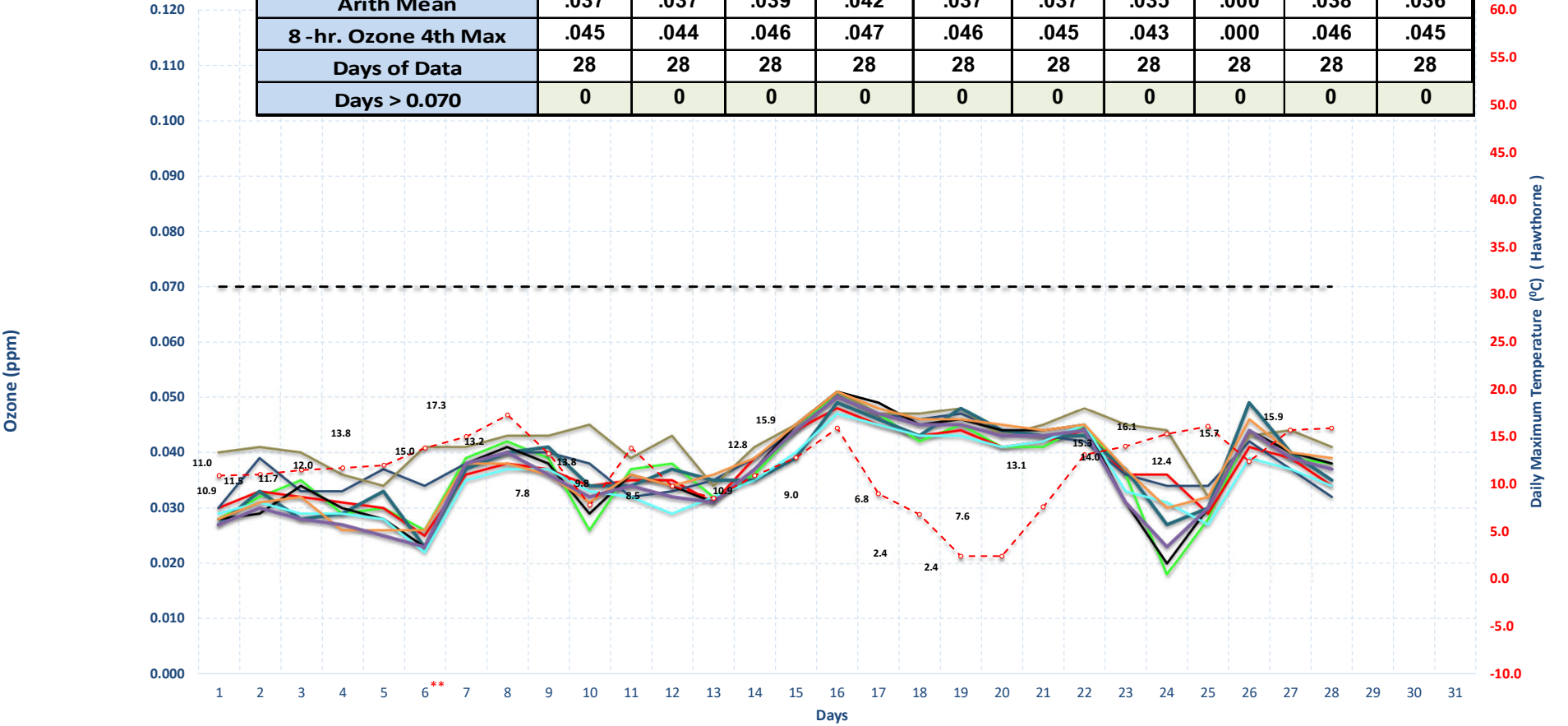
Highest 8-hr Ozone Concentration & Daily Maximum Temperature January 2026

	HB
Arith Mean	.035
8 -hr. Ozone 4th Max	.040
Days of Data	31
Days > 0.070	0



Highest 8-hr Ozone Concentration & Daily Maximum Temperature February 2026

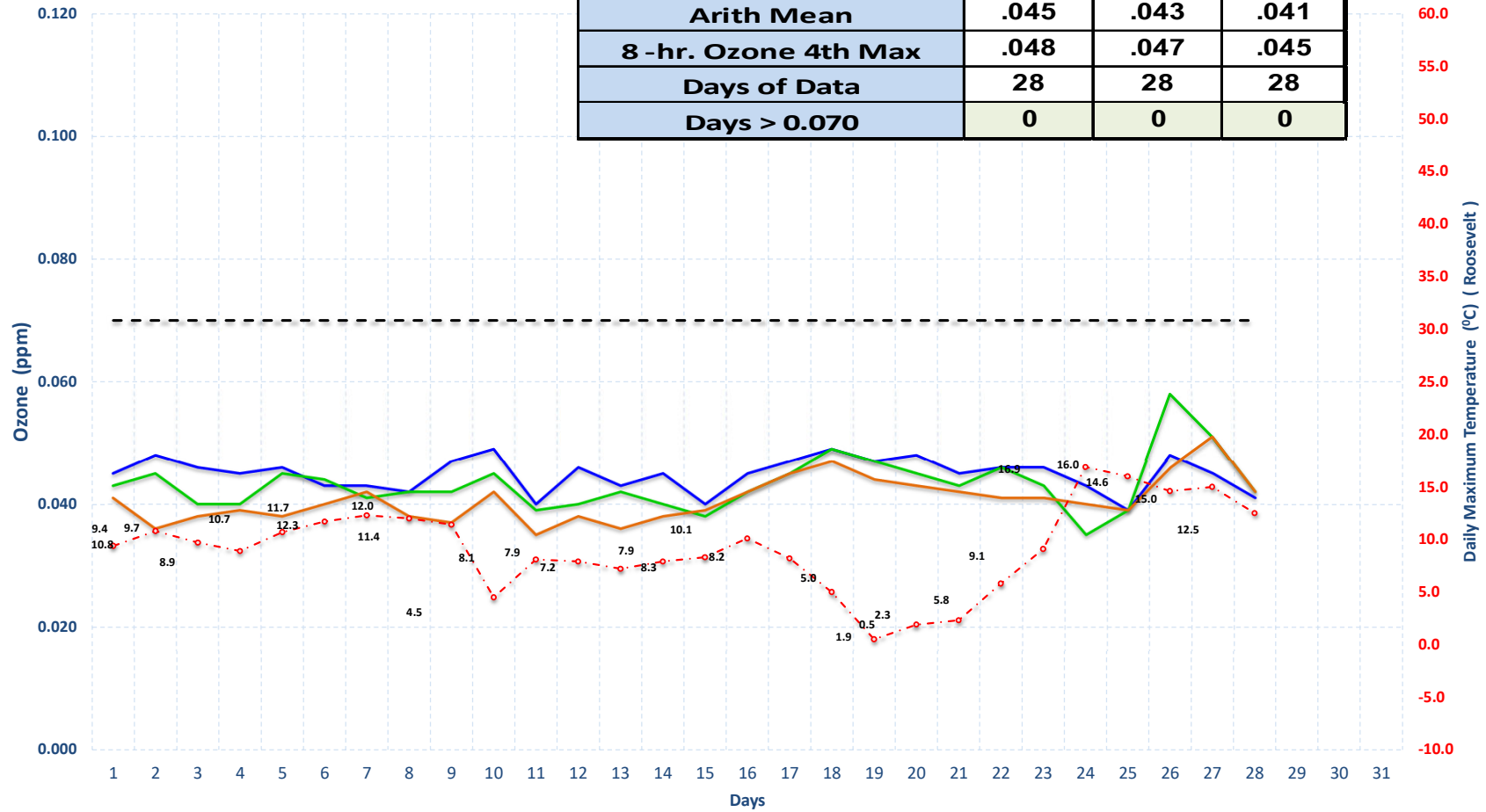
O3 Feb 2026	BV	CV	ED	H3	HV	HW	NR	RB	RP	EQ
Arith Mean	.037	.037	.039	.042	.037	.037	.035	.000	.038	.036
8-hr. Ozone 4th Max	.045	.044	.046	.047	.046	.045	.043	.000	.046	.045
Days of Data	28	28	28	28	28	28	28	28	28	28
Days > 0.070	0	0	0	0	0	0	0	0	0	0



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

Highest 8-hr Ozone Concentration & Daily Maximum Temperature February 2026

	P2	RS	V4
Arith Mean	.045	.043	.041
8 -hr. Ozone 4th Max	.048	.047	.045
Days of Data	28	28	28
Days > 0.070	0	0	0



Price #2

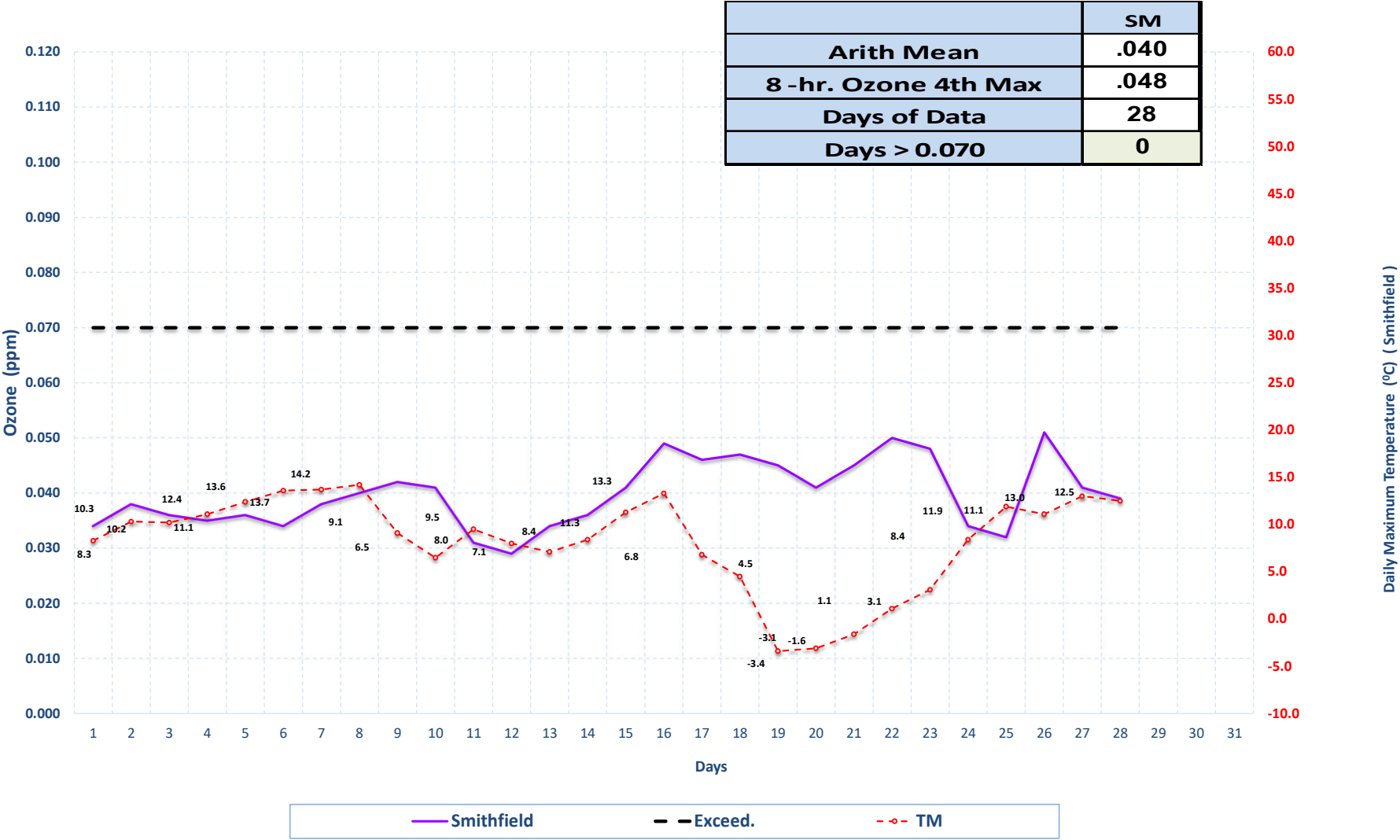
Roosevelt

Vernal

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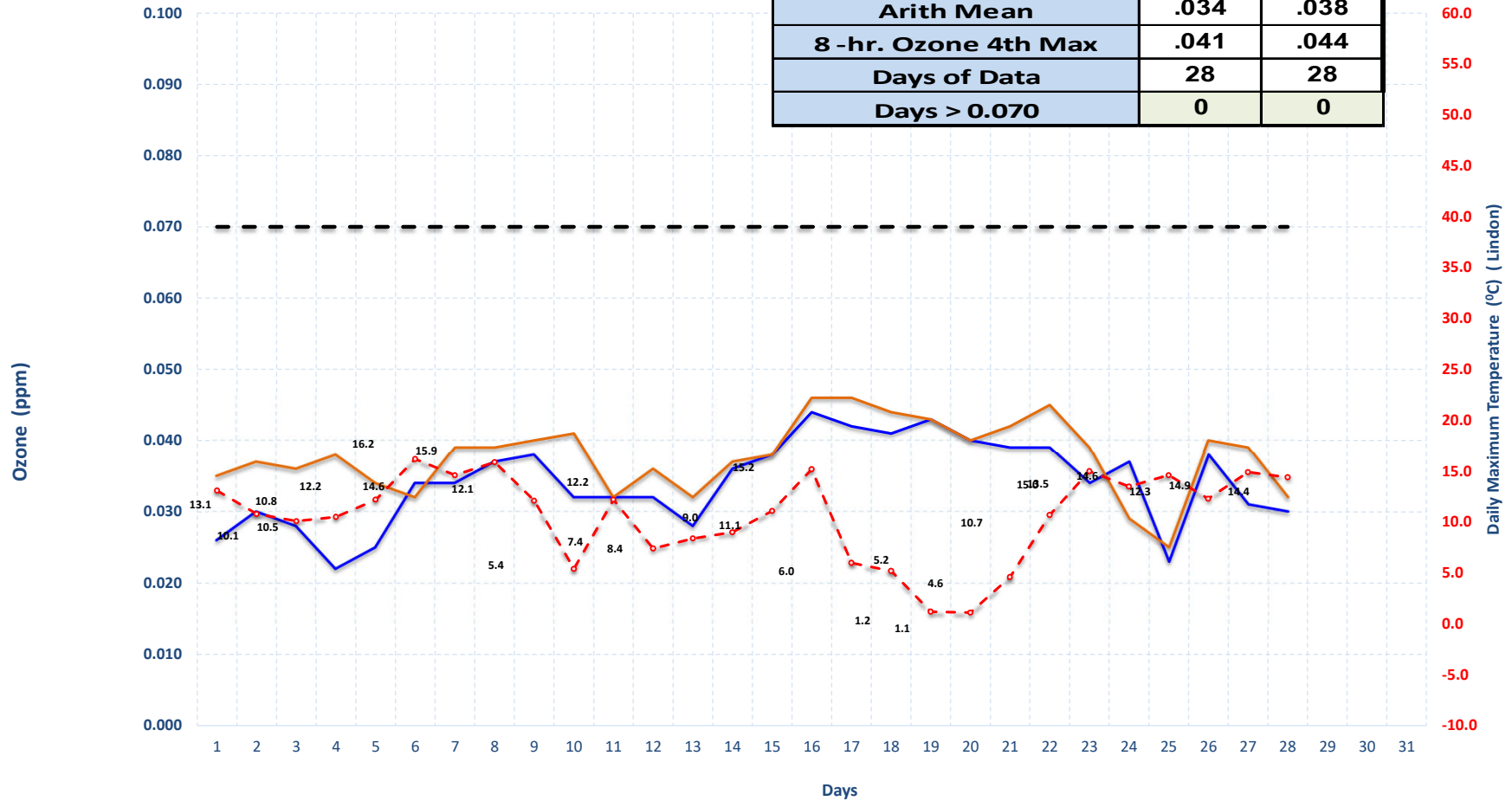
-o- TM

Highest 8-hr Ozone Concentration & Daily Maximum Temperature February 2026



Highest 8-hr Ozone Concentration & Daily Maximum Temperature February 2026

	LN	SF
Arith Mean	.034	.038
8-hr. Ozone 4th Max	.041	.044
Days of Data	28	28
Days > 0.070	0	0



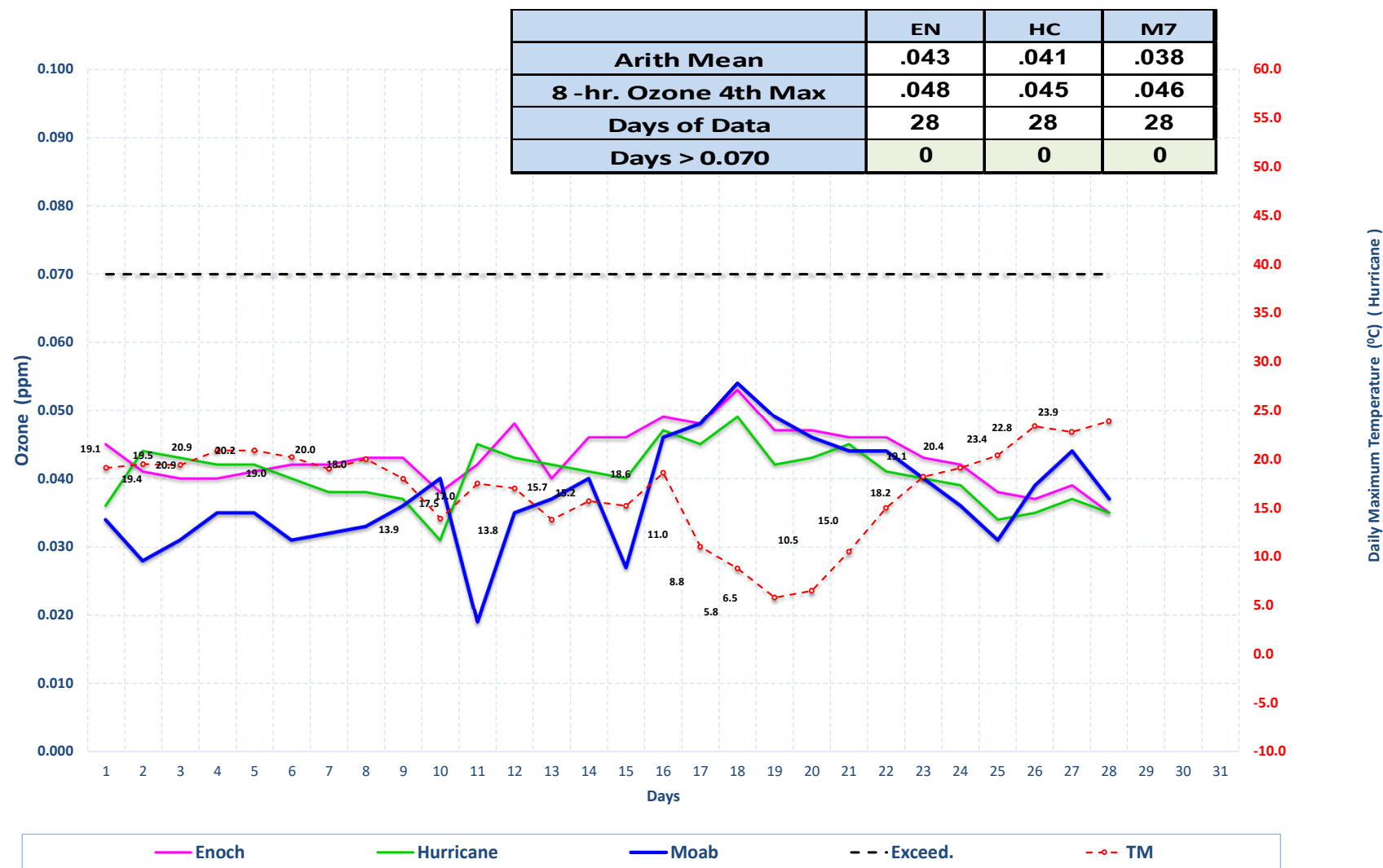
— London

— Spanish Fork

- - Exceed.

- - TM

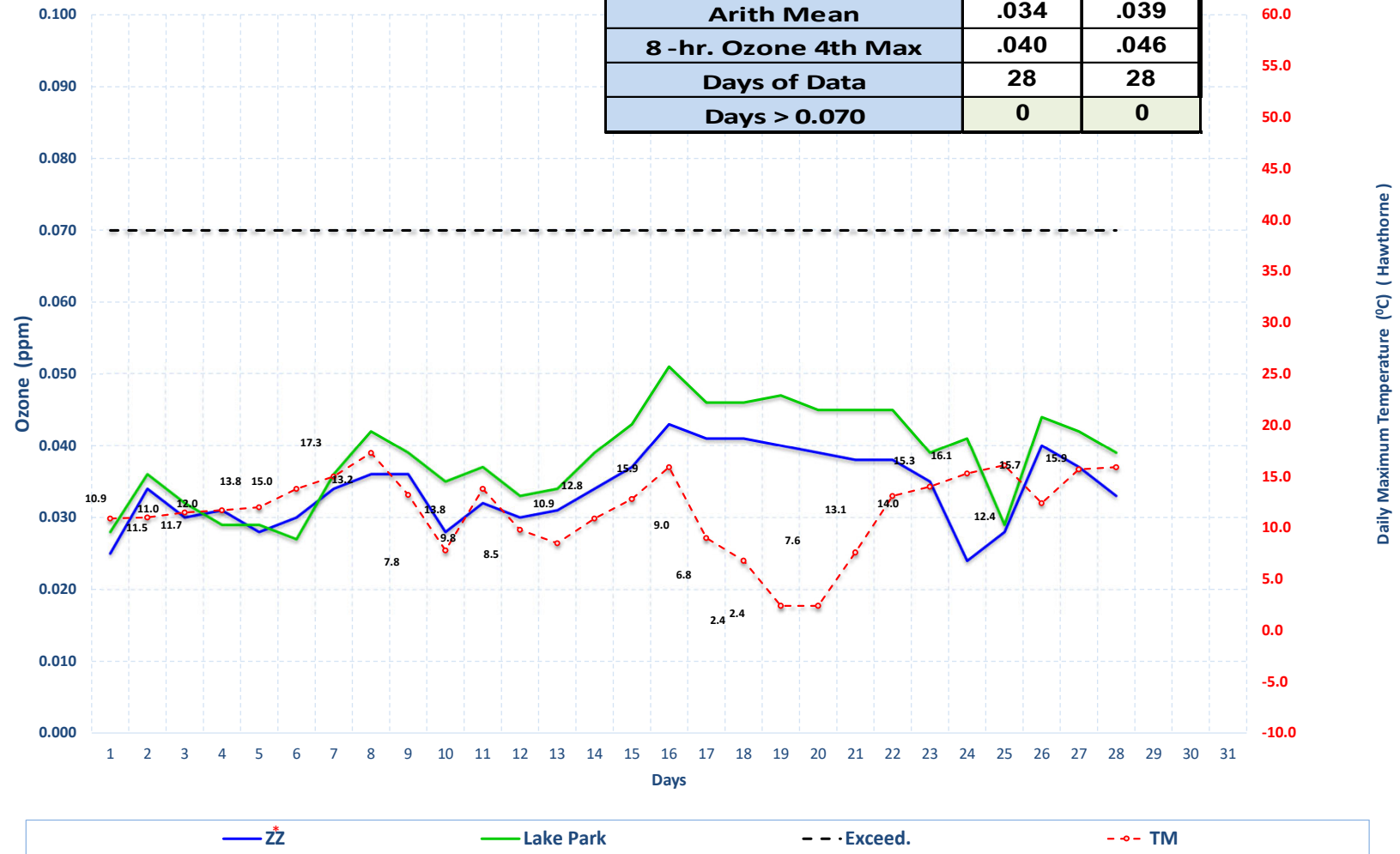
Highest 8-hr Ozone Concentration & Daily Maximum Temperature February 2026



Highest 8-hr Ozone Concentration & Daily Maximum Temperature February 2026

Stations Monitoring the Inland Port Development

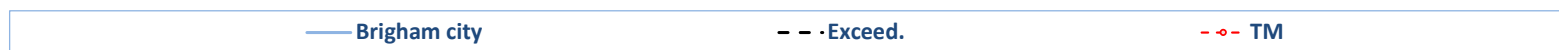
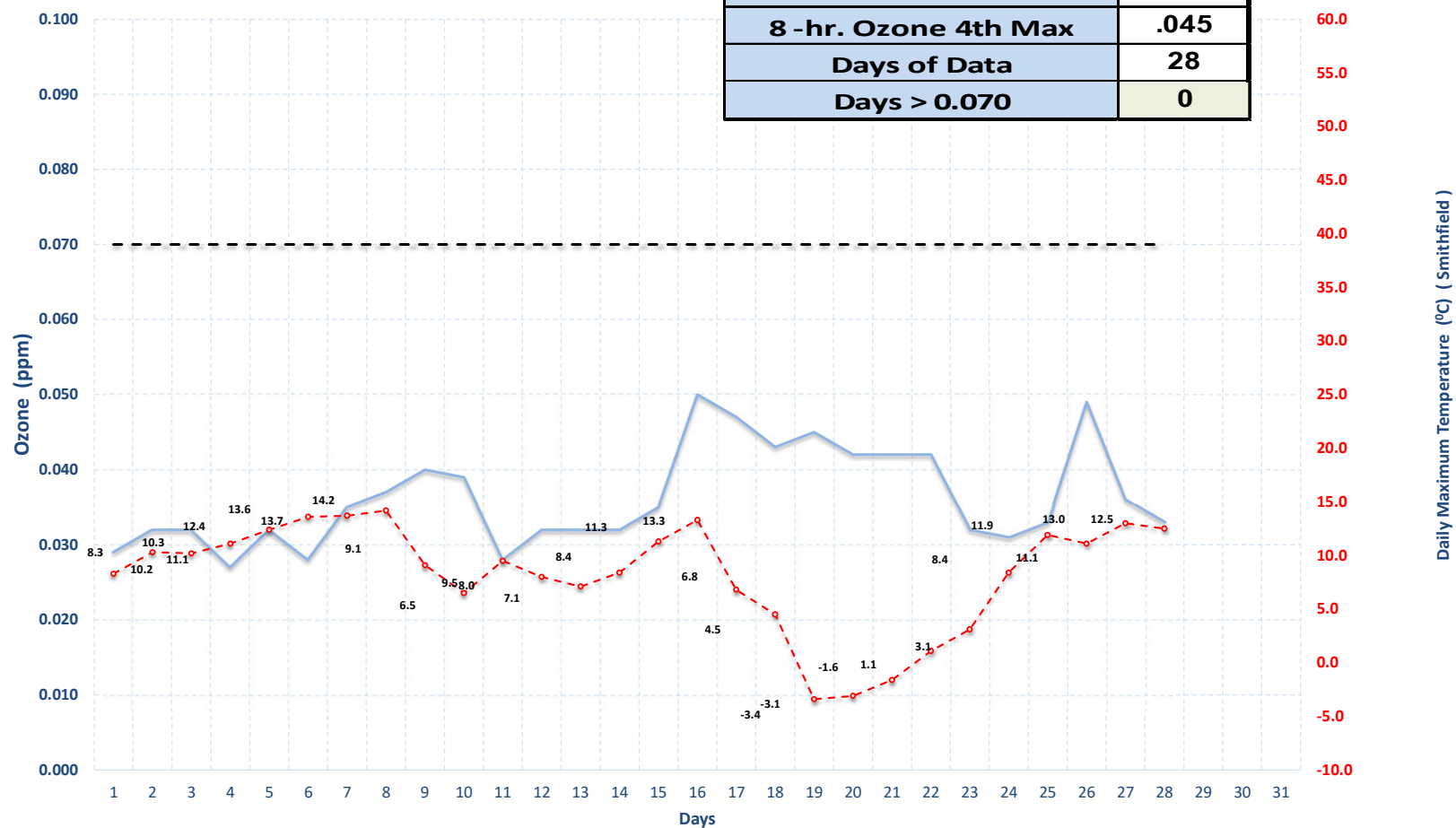
	ZZ	LP
Arith Mean	.034	.039
8 -hr. Ozone 4th Max	.040	.046
Days of Data	28	28
Days > 0.070	0	0



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This site was previously named IP

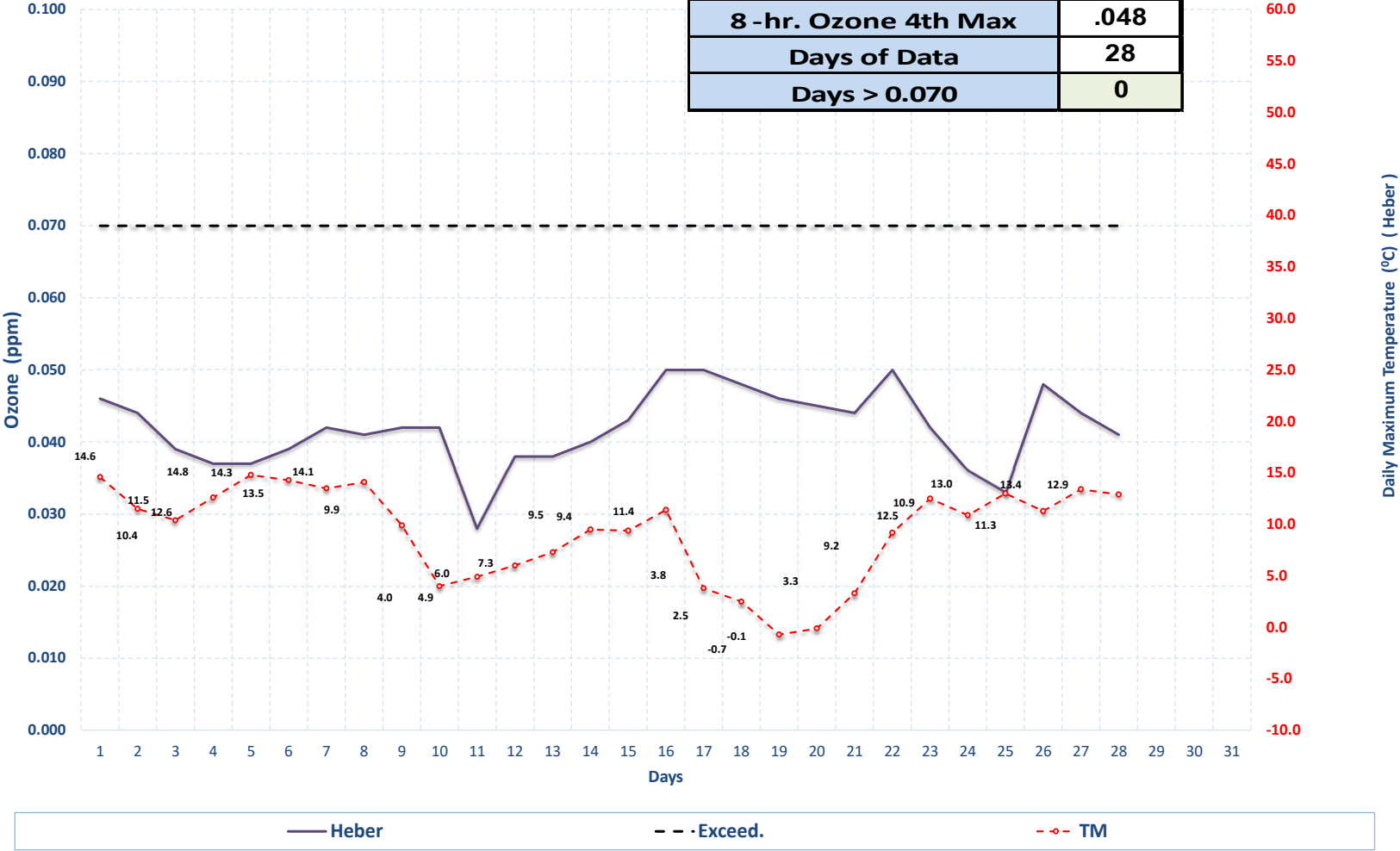
Highest 8-hr Ozone Concentration & Daily Maximum Temperature February 2026

	BG
Arith Mean	.036
8 -hr. Ozone 4th Max	.045
Days of Data	28
Days > 0.070	0



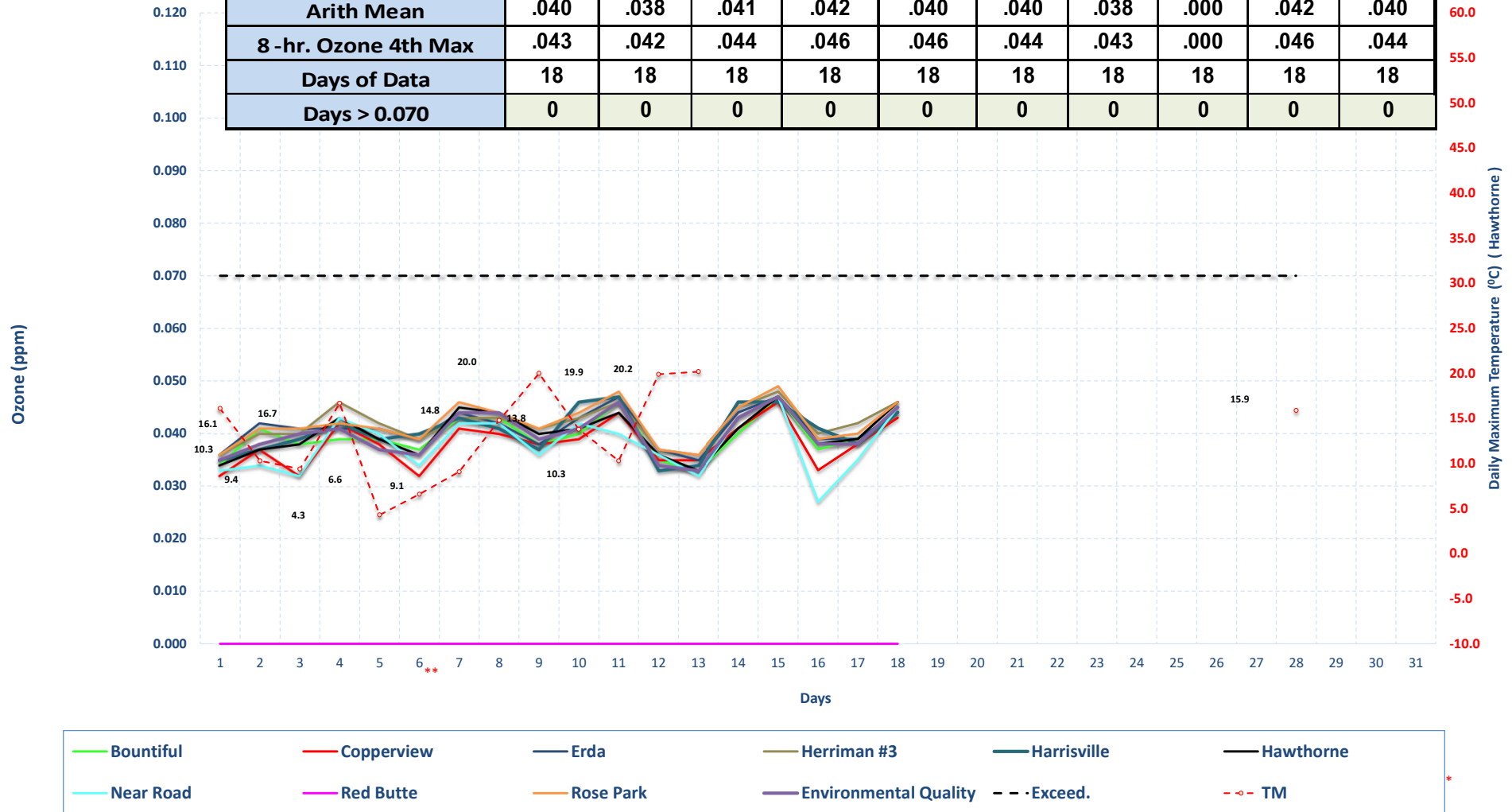
Highest 8-hr Ozone Concentration & Daily Maximum Temperature February 2026

	HB
Arith Mean	.042
8 -hr. Ozone 4th Max	.048
Days of Data	28
Days > 0.070	0



Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2026

O3 Mar 2026	BV	CV	ED	H3	HV	HW	NR	RB	RP	EQ
Arith Mean	.040	.038	.041	.042	.040	.040	.038	.000	.042	.040
8-hr. Ozone 4th Max	.043	.042	.044	.046	.046	.044	.043	.000	.046	.044
Days of Data	18	18	18	18	18	18	18	18	18	18
Days > 0.070	0	0	0	0	0	0	0	0	0	0

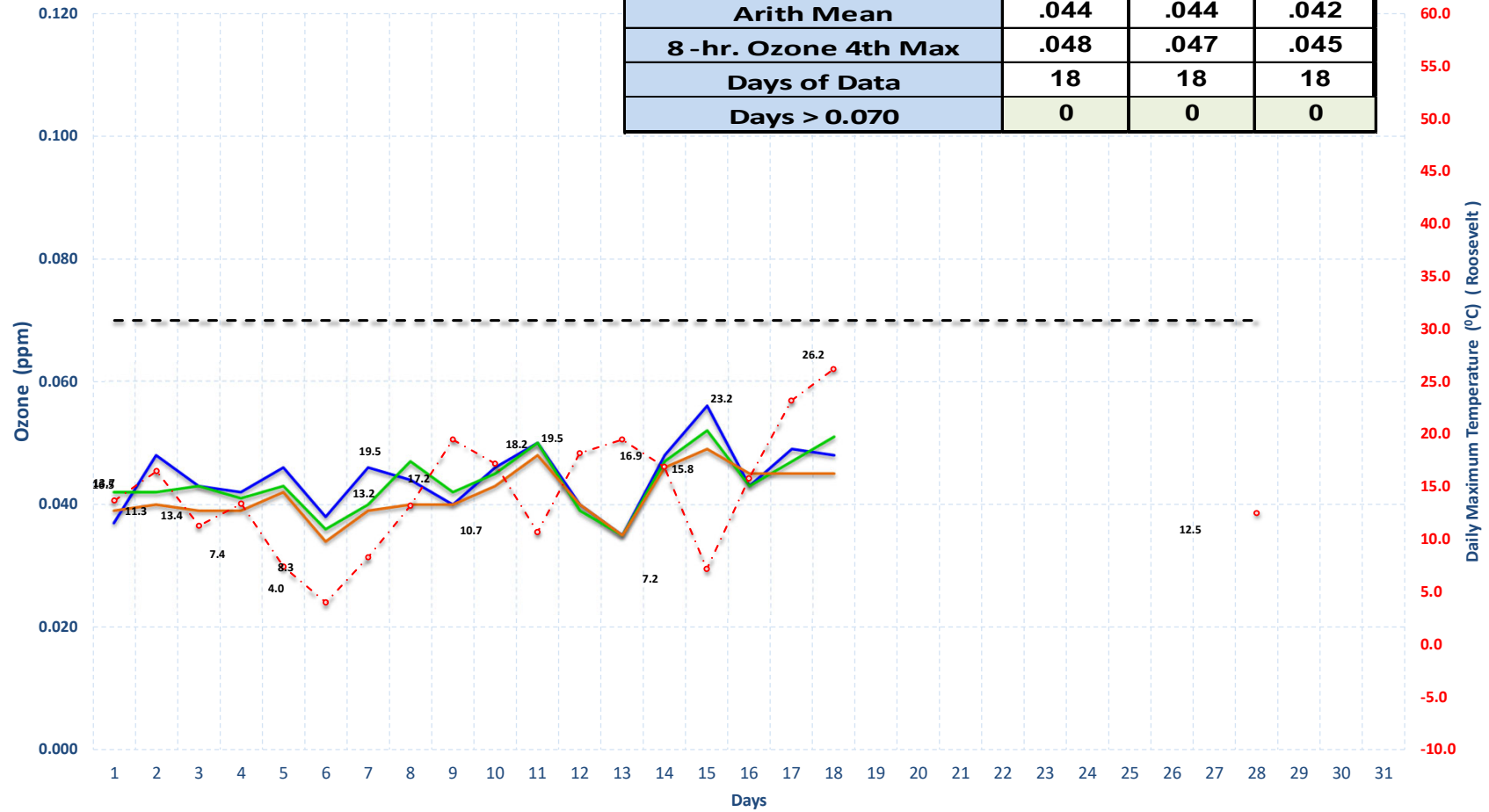


* Environmental Quality (EQ) previously named Technical Support Center (TSC)

** Controlling Monitor

Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2026

	P2	RS	V4
Arith Mean	.044	.044	.042
8 -hr. Ozone 4th Max	.048	.047	.045
Days of Data	18	18	18
Days > 0.070	0	0	0



Price #2

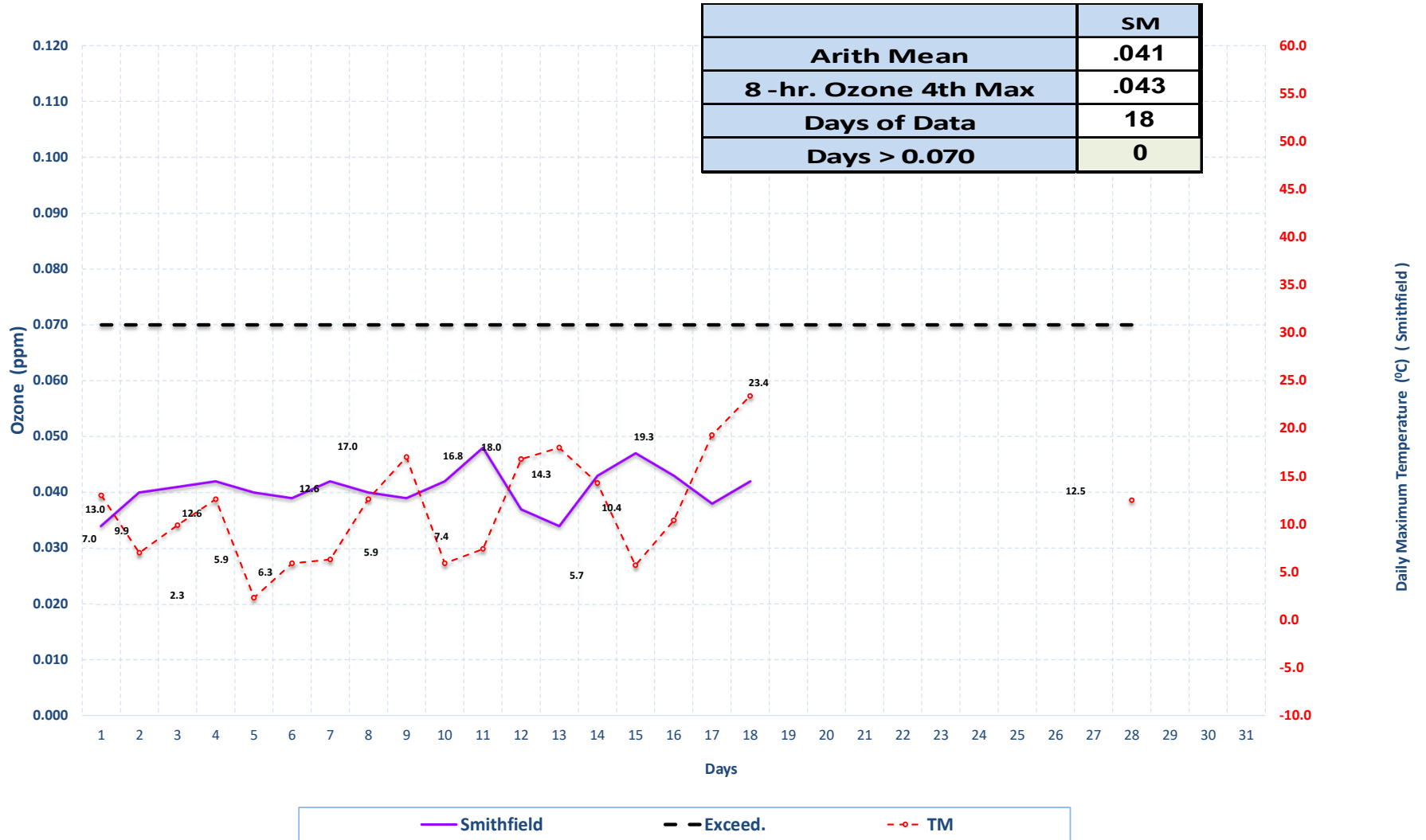
Roosevelt

Vernal

-- Exceed.

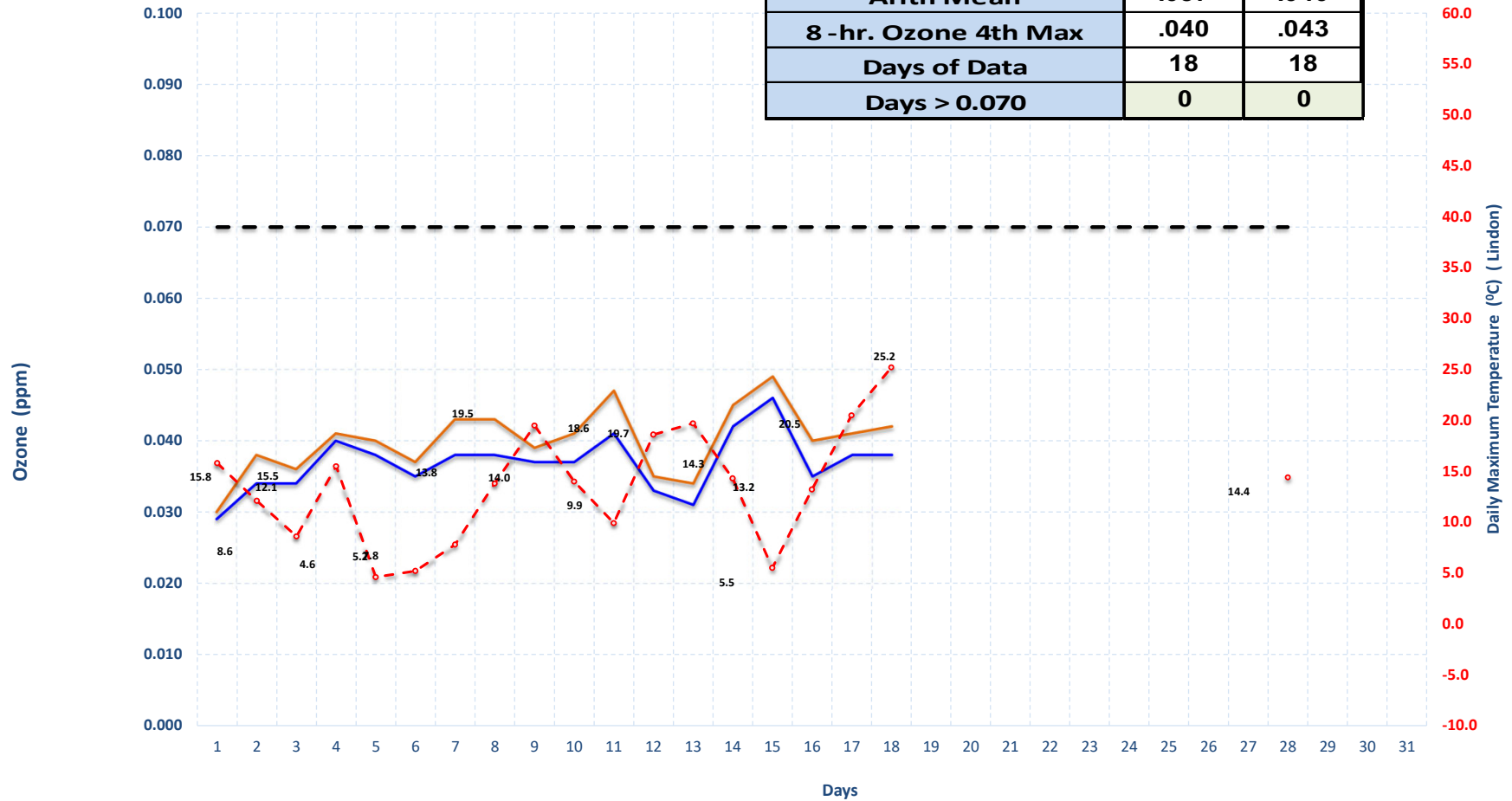
-o- TM

Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2026



Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2026

	LN	SF
Arith Mean	.037	.040
8 -hr. Ozone 4th Max	.040	.043
Days of Data	18	18
Days > 0.070	0	0



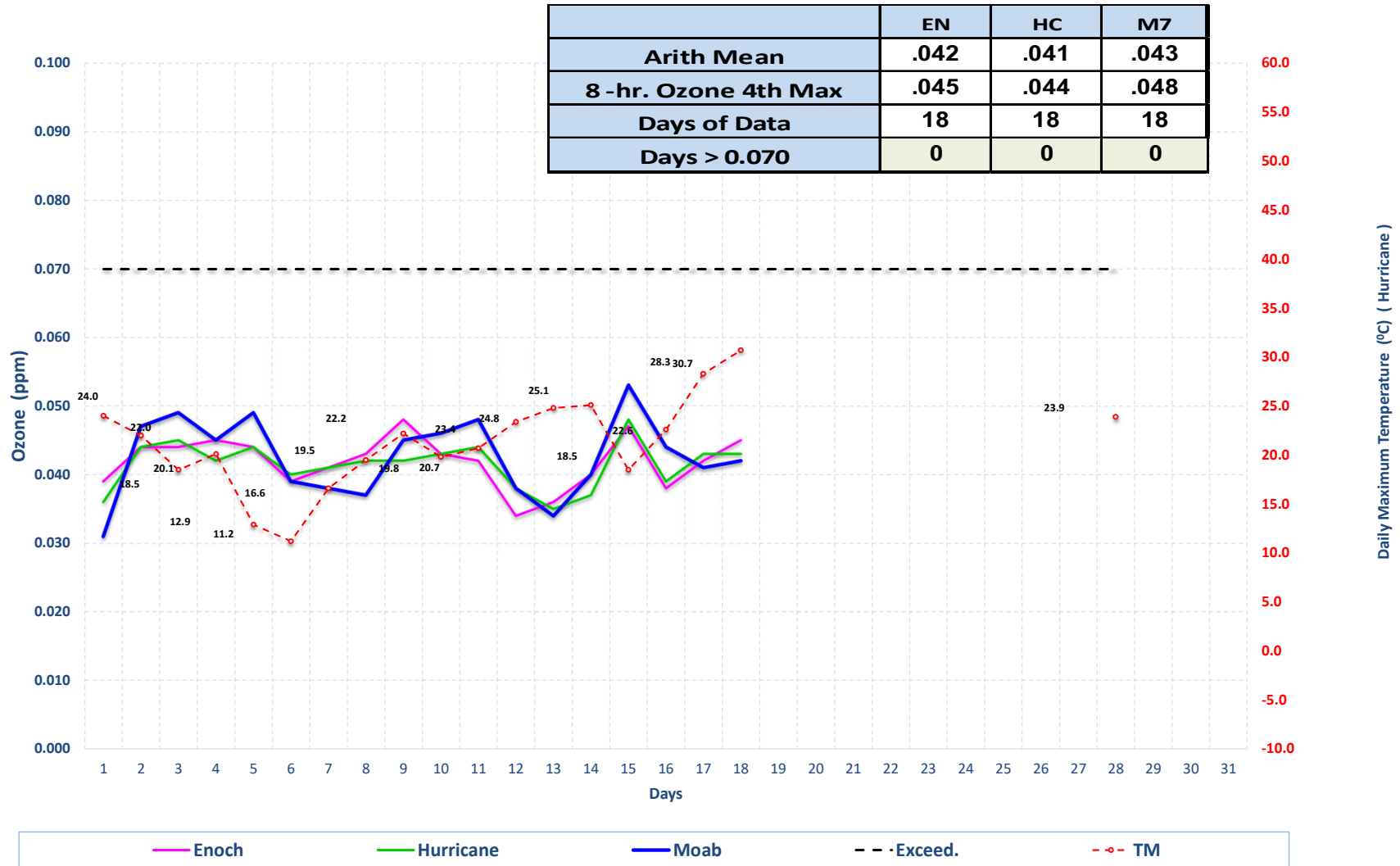
— Lindon

— Spanish Fork

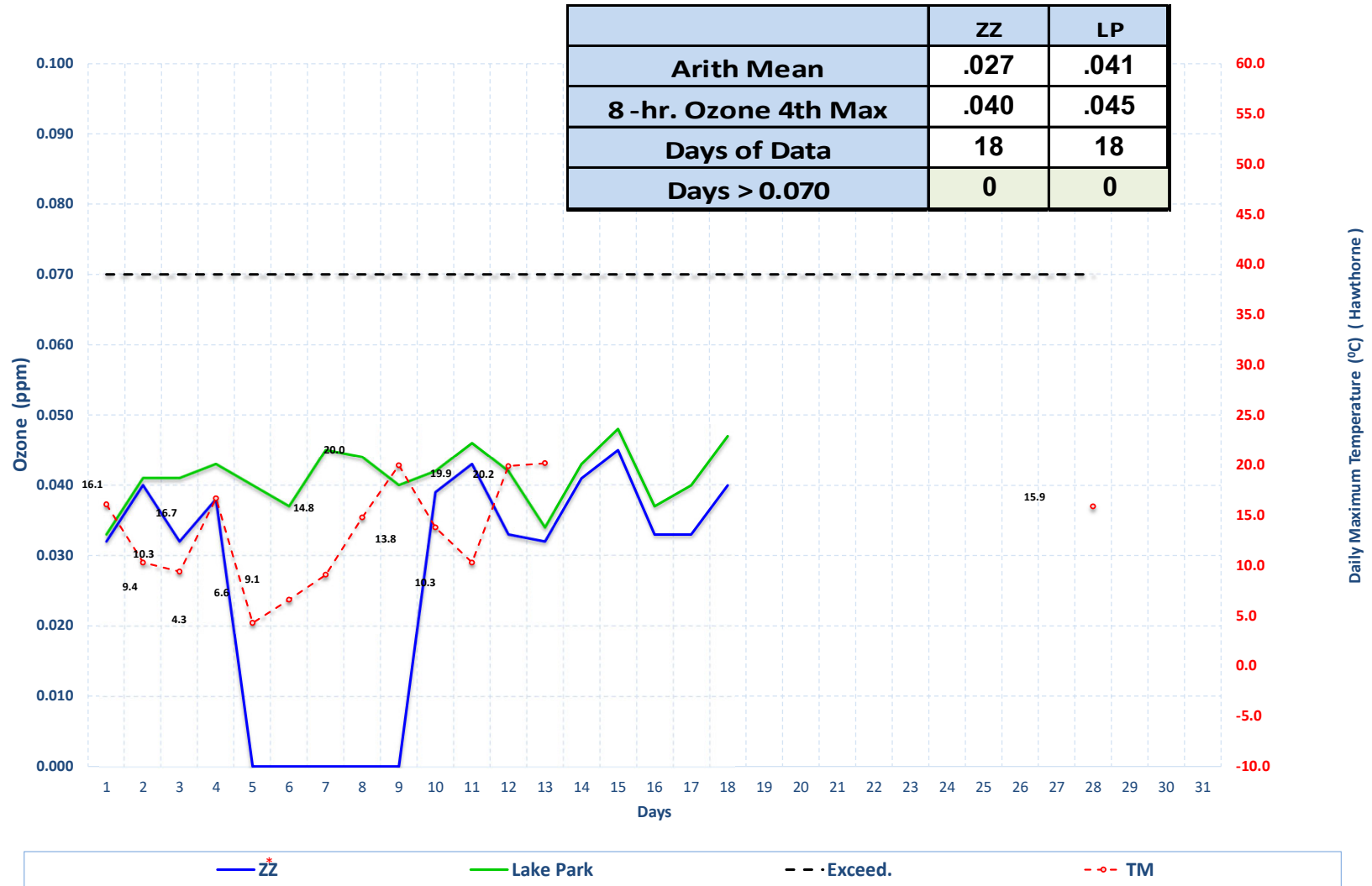
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- - - TM

Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2026

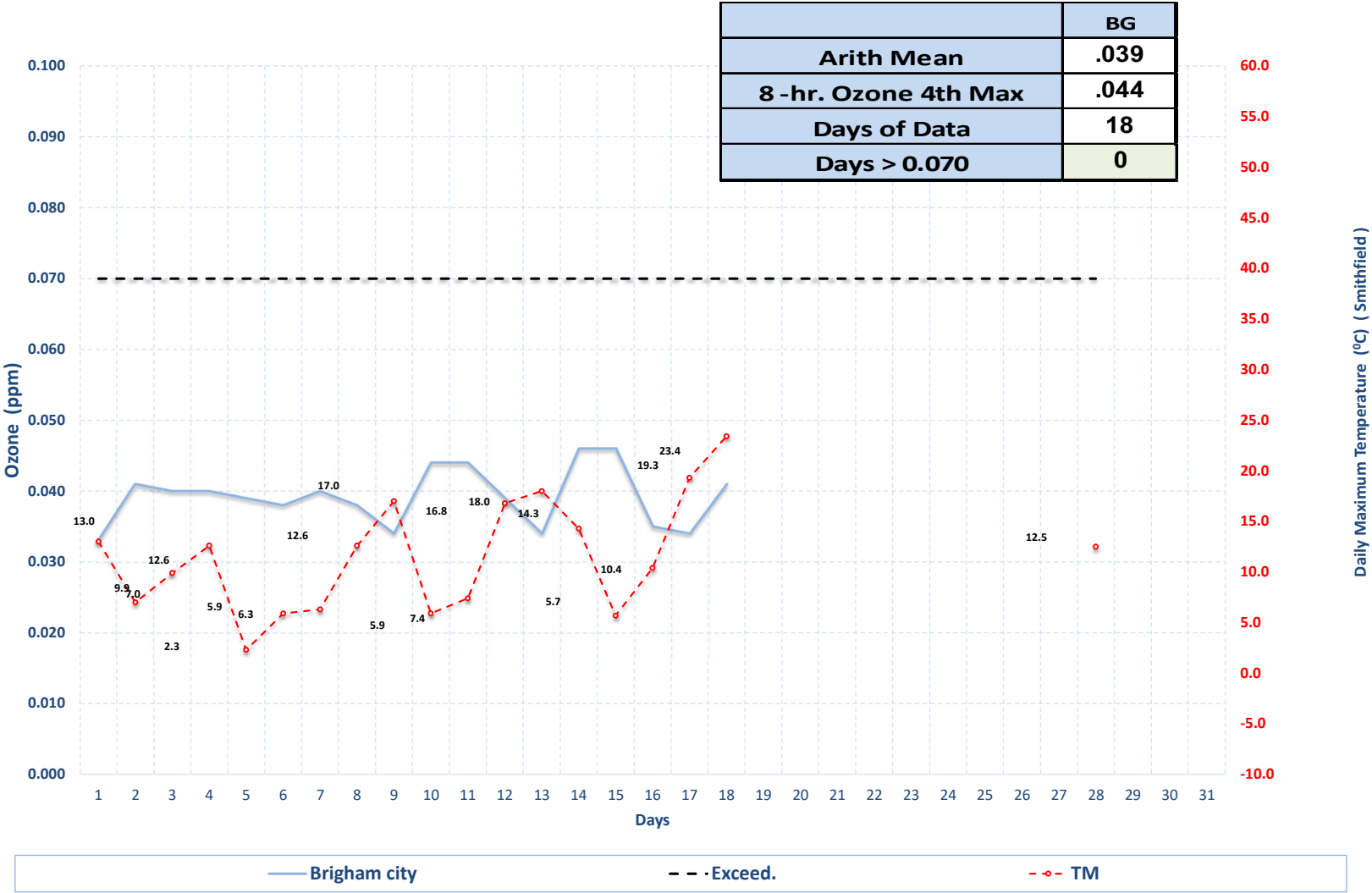


Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2026 Stations Monitoring the Inland Port Development



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Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2026



Highest 8-hr Ozone Concentration & Daily Maximum Temperature March 2026

