



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

Air Quality Board

Erin Mendenhall *Chair*
Cassady Kristensen, *Vice-Chair*
Kevin R. Cromar
Mitra Basiri Kashanchi
Randal S. Martin
Alan Matheson
Arnold W. Reitze Jr.
Michael Smith
William C. Stringer
Bryce C. Bird,
Executive Secretary

DAQ-096-18

UTAH AIR QUALITY BOARD MEETING

FINAL AGENDA

Wednesday, January 2, 2019
195 North 1950 West, Salt Lake City, Utah 84116

Board Working Lunch – 11:30 a.m.

Four Corners Conference Rooms (4th Floor)

Staff update on the Division of Air Quality Compliance Program.

Board Meeting – 1:30 p.m.
Conference Room 1015 (1st Floor)

- I. Call-to-Order
- II. Date of the Next Air Quality Board Meeting: February 6, 2019
- III. Approval of the Minutes for November 7, 2018, Board Meeting.
- IV. Final Adoption: SIP Subsection IX.A.31: Control Measures for Area and Point Sources, Fine Particulate Matter, Serious Area PM_{2.5} SIP for the Salt Lake City, UT Nonattainment Area, as Amended. Presented by Bill Reiss.
- V. Final Adoption: Change in Proposed Rule R307-110-10. Section IX, Control Measures for Area and Point Sources, Part A, Fine Particulate Matter. Presented by Thomas Gunter.
- VI. Final Adoption: SIP Subsection IX. Part H: Emission Limits and Operating Practices. Specifically Requirements in Subparts H. 1, 2, 11, and 12, as Amended. Presented by Bill Reiss.
- VII. Final Adoption: Change in Proposed Rule, R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits. Presented by Thomas Gunter.
- VIII. Final Adoption: Change in Proposed Rule R307-511. Oil and Gas Industry: Associated Gas Flaring. Presented by Thomas Gunter.

IX. Informational Items.

- A. Regional Haze State Implementation Plan Amendment. Presented by Jay Baker.
- B. Air Toxics. Presented by Robert Ford.
- C. Compliance. Presented by Jay Morris and Harold Burge.
- D. Monitoring. Presented by Bo Call.
- E. Other Items to be Brought Before the Board.
- F. Board Meeting Follow-up Items.

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

Working Lunch Meeting



UTAH DEPARTMENT of
ENVIRONMENTAL QUALITY
**AIR
QUALITY**

DIVISION OF AIR QUALITY COMPLIANCE SUMMARY

Air Quality Compliance

- Major and Minor Source Compliance sections are responsible for ensuring that all regulatory requirements are met at sources subject to state rules and permit requirements.
- ATLAS is responsible for Asbestos and Lead-Based Paint programs.
- Compliance is achieved through inspections, audits, and enforcement. Industrial sources are inspected to ensure they are complying with the rules.
- Division of Air Quality rules and policies are intended to achieve voluntary compliance, encourage continuous compliance, ensure consistent application of the Division's rules throughout the state, and provide a mechanism for documentation if formal enforcement action is necessary.

Inspection Process

- Pre-Inspection
- Inspection
 - Pre-inspection meeting
 - Source inspection
 - Post-inspection meeting
- Inspection Memo
- Management Review



Inspection Resources

The Division of Air Quality (DAQ) inspects 1546 permitted sources.

- 1471 minor sources
- 75 major sources

Total number of DAQ inspectors: 30

- Stack test review: 3 inspectors
- Continuous Emission Monitoring Systems (CEMS): 1 inspector
- Major and minor sources: 19 inspectors
- ATLAS program: 7 inspectors

Inspection Targeting

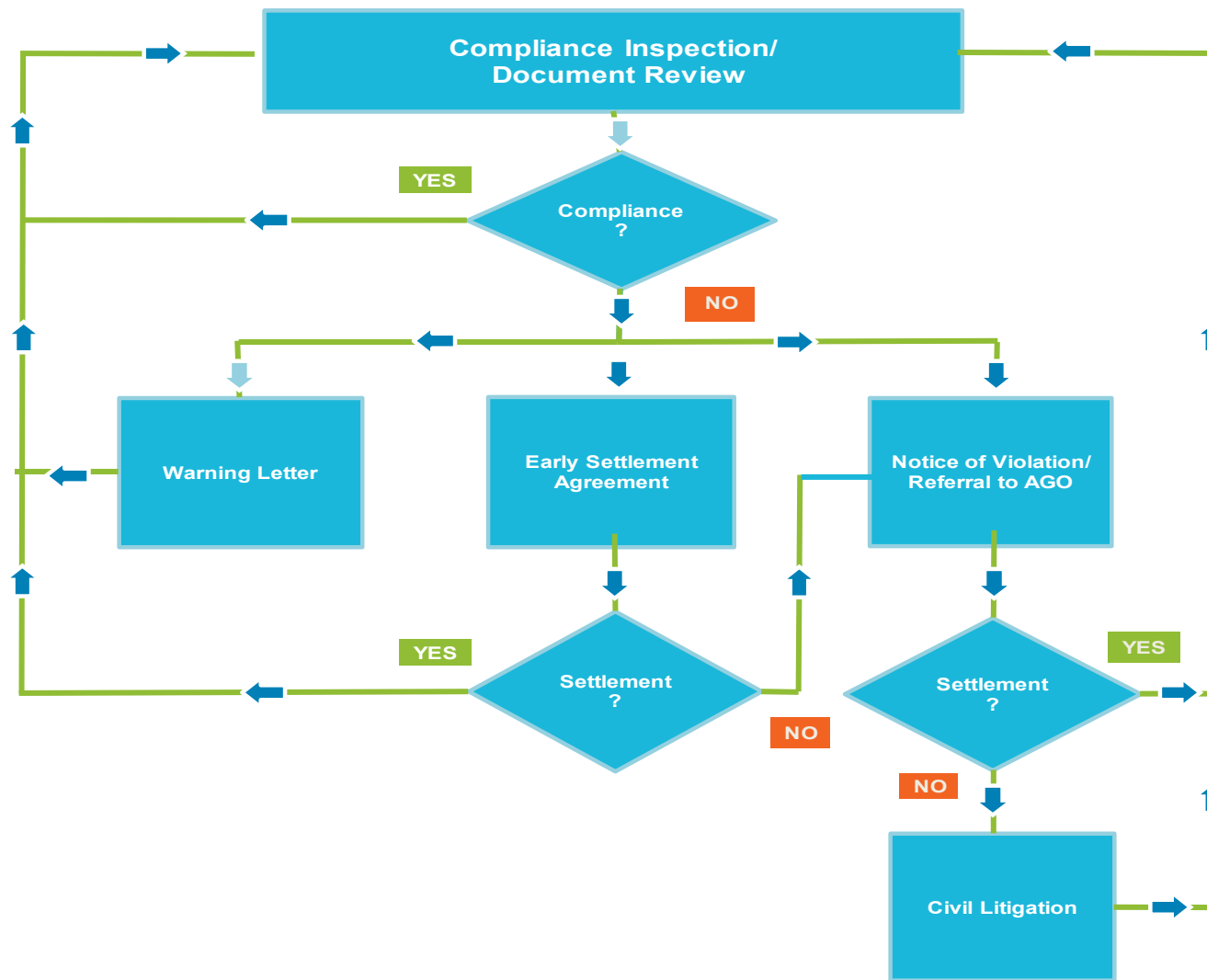
Major: Annual or multiple inspections

Minor: At least every 5 years.
Goal: every 3 years

Complaints: 391 in FY 2018



Compliance/Enforcement Cycle



Two Distinct Processes for Resolution

Compliance Advisory (CA) and Early Administrative Settlement

- Resolves the alleged violations without admissions of findings.
- Requires a return to full compliance
- Requires a plan to prevent future violations
- Uses the Penalty Rule (R307-130) to determine reasonable and appropriate penalties
- Offers possible 20% reduction for early settlement.

Notice Of Violation (NOV) Formal Resolution

- Violations are final unless appealed within 30 days.
- Settlement is formal.
- Utah Office of the Attorney General may file for collection of penalties in civil court.
- Uses the Penalty Rule (R307-130) to determine reasonable and appropriate penalties

Purpose of Penalties

EPA's penalty policy has two components:

- Deterrence of noncompliance through a penalty
- Adjustments for a fair and equitable penalty

Supplemental Environmental Projects (SEP)

- Improvement to the environmental beyond what is required by law
- Offsets a portion of the penalty, typically 1.5: 1 ratio

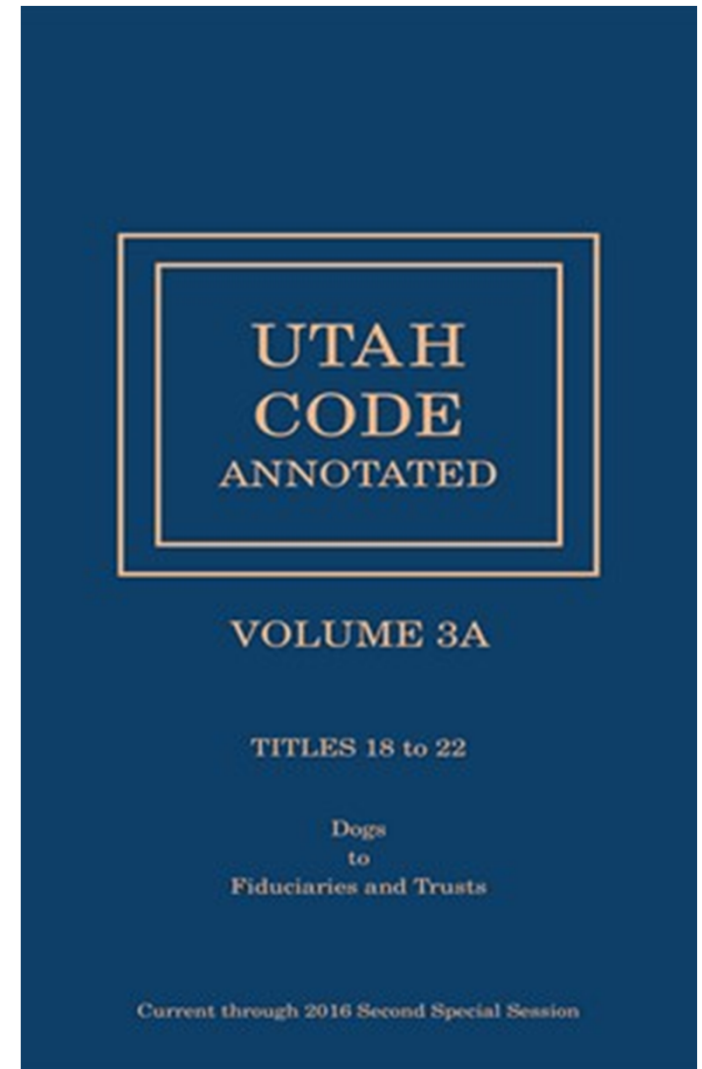
Repeat Violations

- Four repeat violations in the last 5 years
- 7381 inspections in those 5 years
- .05 % repeat violations



Utah Air Conservation Act

19-2-115(2)(a) A person who violates this chapter, or any rule, order, or permit issued or made under this chapter is subject in a civil proceeding to a penalty not to exceed \$10,000 per day for each violation.



19-2-104 Powers of the Board

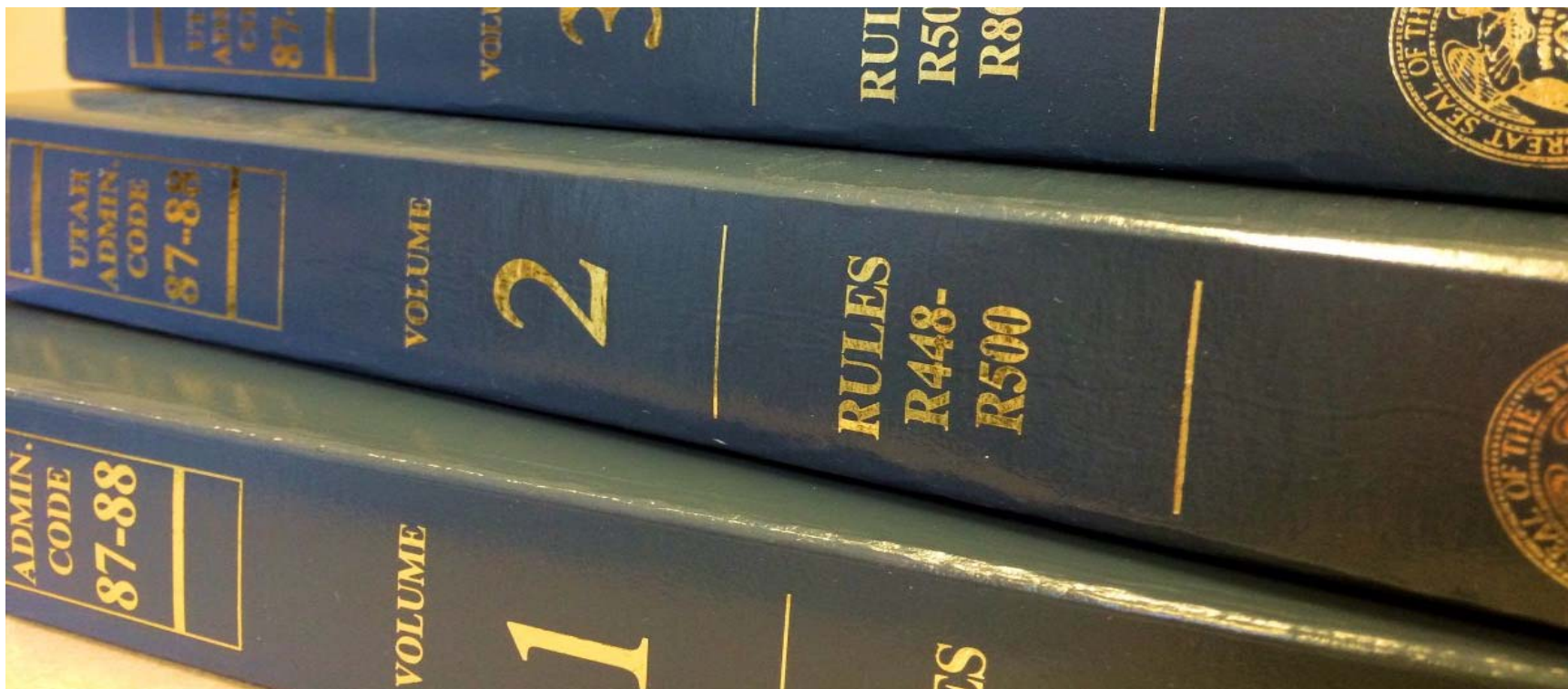
- (3)(b)(i) Review a settlement negotiated by the Director...that results in a civil penalty of \$25,000 or more; and approve or disapprove the settlement.
- Since 2014: three settlements greater than \$25,000
- Since 2014: 7381 inspections performed



Utah Administrative Code

R307-130 General Penalty Policy

Violations are grouped in four general categories based on the potential for harm and the nature and extent of the violations. Penalty ranges for each category are listed.



Category A

Penalties: \$7,000-10,000 per day

Violations with high potential for impact on public health and the environment including:

- Violation of emission standards and limitations of NESHAP.
- Emissions contributing to nonattainment area or PSD increment exceedences.
- Emissions resulting in documented public health effects and/or environmental damage.

Category B

Penalties: \$2,000-7,000 per day

Violations of the Utah Air Conservation Act, applicable State and Federal regulations, and orders including:

- Significant levels of emissions resulting from violations of emission limitations or other regulations which are not within Category A.
- Substantial non-compliance with monitoring requirements.
- Significant violations of approval orders, compliance orders, and consent agreements not within Category A.
- Significant and/or knowing violations of "notice of intent" and other notification requirements, including those of NESHAP.
- Violations of reporting requirements of NESHAP.

Category C

Penalties: Up to \$2,000 per day

Minor violations of the Utah Air Conservation Act, applicable State and Federal Regulations, and orders having no significant public health or environmental impact including:

- Reporting violations
- Minor violations of monitoring requirements, orders and agreements
- Minor violations of emission limitations or other regulatory requirements.

Category D

Penalties: Up to \$299.00

Violations of specific provisions of R307 considered minor including:

- Violation of automobile emission standards and requirements
- Violation of wood-burning regulations by private individuals
- Open burning violations by private individuals.

Adjustments

Adjustments are made based upon:

- The type of emissions involved
- Good faith effort to comply
- Degree of willfulness and/or negligence
- History of compliance or noncompliance
- Economic benefit of noncompliance
- Inability to pay

All penalty money is deposited into the state general fund.



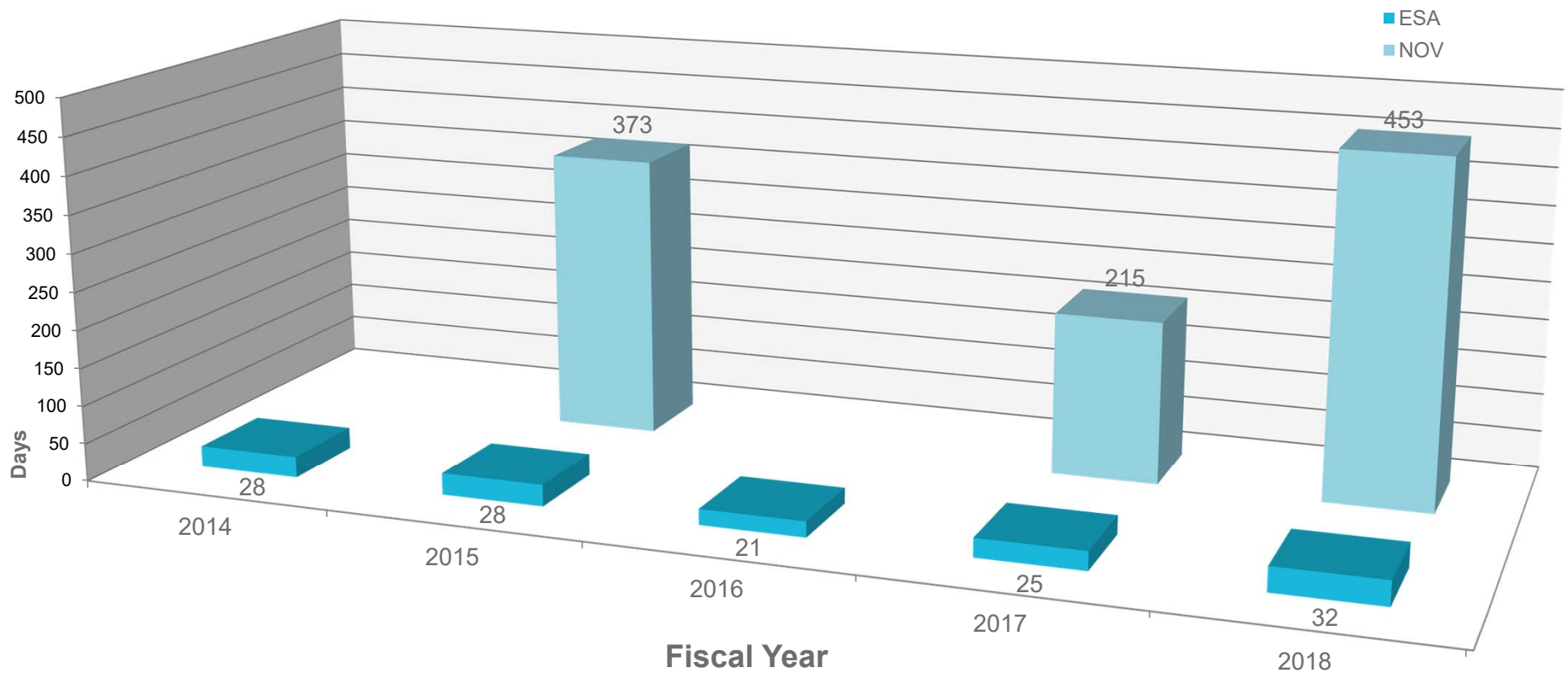
Penalty Calculation Worksheet

Utah Division of Air Quality General Administrative Penalty Worksheet														
Source:								Class:		Home				
SID No.:		HPV:						Violation Date:		Penalty Policy				
								Gravity Criteria (Gc) No(0), Possibly(1), Probably(2), Definitely(3)		Gravity Criteria				
Table 1: Gravity Criteria														
Citation	Description of the violation Description of Events Resulting in Excess Emissions	E	V	e	n	t	s	Gc 1	Gc 2	Gc 3	Gc 4	Gc 5	Daily Gravity	Accumulated Gravity
Gc 5 History of violations within the last five (5) years? Enter "d" in Category →													\$0.00	\$0.00
Violations of the same rule within the last five (5) years? Enter "d" in Category →													\$0.00	\$0.00
Total Gravity												\$0.00	\$0.00	
Table 2: Adjustments														
Economic Benefit		EPA "BEN" Model (Collected)												
Other														
		Other Monies Collected												
		Early Settlement Reduction (20%) -										Remove 20% Status	\$0.00	
Total Penalty												\$0.00		
Gravity Criteria Definitions														
Gc 1. Was the violation a result of excess emissions and/or reporting?														
(1) Answer "no"	If the violation was not the result emissions, reporting, or other													
(1) Answer "possibly"	If a minor reporting or other problem occurred, but no emissions were involved													
(2) Answer "probably"	If a reporting or other problem occurred which involved emissions													
(3) Answer "definitely"	If a permit reporting or other significant problem occurred involving emissions													
Gc 2. Was it a willful or knowing violation?														
(1) Answer "no"	If the violator obviously did not know that the action or inaction constituted a violation?													
(1) Answer "possibly"	If the violator should have known													
(2) Answer "probably"	If the violator likely knew													

Working
document with
categories and
adjustments
derived from
R307-130

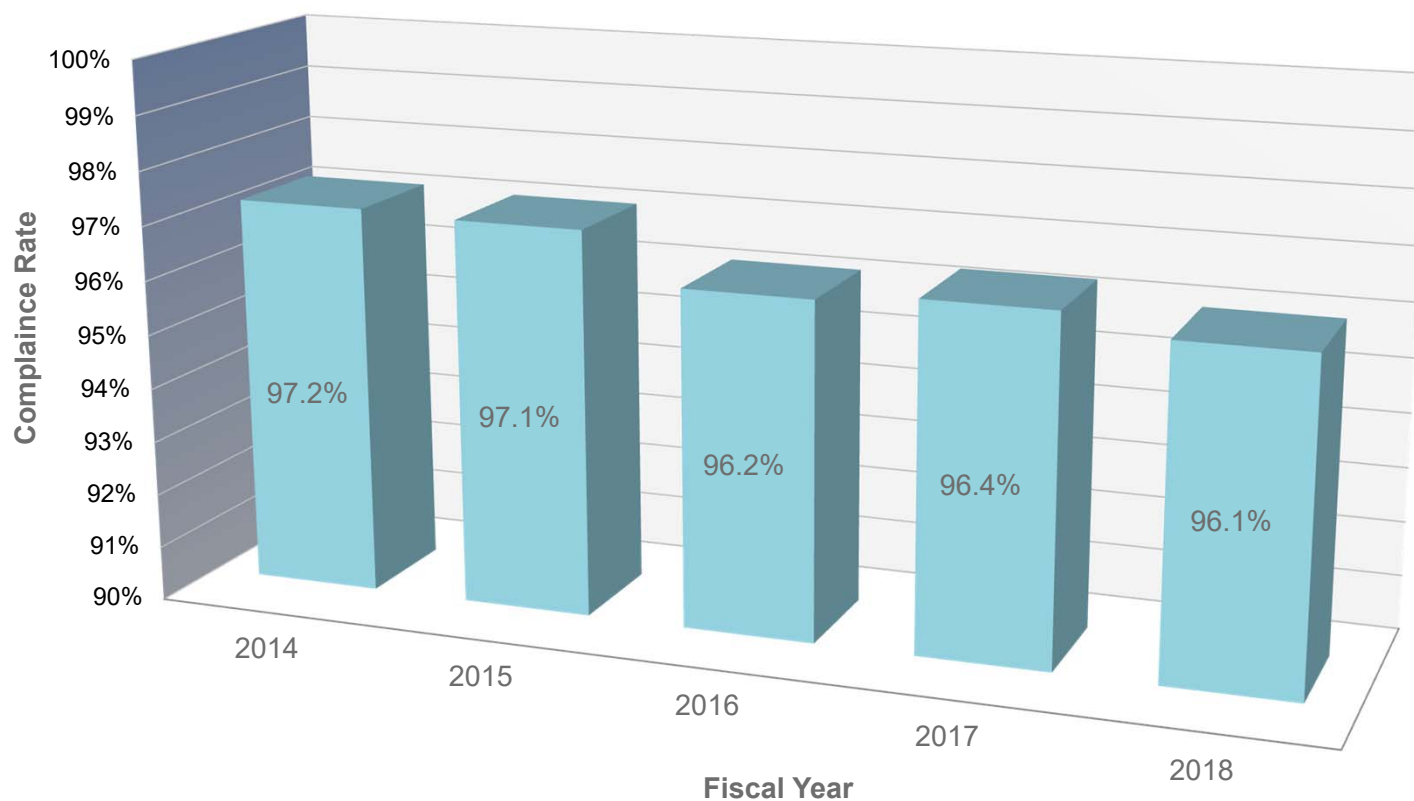
Return to Compliance

Major/Minor Average Return to Compliance SFY 2014-2018



Compliance Rates

**Major & Minor Source Compliance Rates
SFY 2014 - 2018**



Board Meeting

ITEM 3



State of Utah

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Executive Secretary

UTAH AIR QUALITY BOARD MEETING

November 7, 2018 – 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116

DRAFT MINUTES

I. Call-to-Order

Erin Mendenhall called the meeting to order at 1:33 p.m.

Board members present: Erin Mendenhall, Kevin Cromar, Randal Martin, Alan Matheson, Arnold Reitze, and William Stringer,

Excused: Cassady Kristensen, Mitra Kashanchi, and Michael Smith

Executive Secretary: Bryce Bird

II. Date of the Next Air Quality Board Meeting: January 2, 2019

There are currently no action items for a December meeting. In addition to the regular Board meeting on January 2, 2019, there will be a Board working lunch at 11:30 a.m.

III. Approval of the Minutes for October 3, 2018, Board Meeting.

Mr. Cromar and Mr. Reitze submitted grammatical corrections.

- Arnold Reitze moved to approve the minutes as amended. Randal Martin seconded. The Board approved unanimously.

IV. Propose for Public Comment: Amend R307-101-2. Definitions. Presented by Thomas Gunter.

Thomas Gunter, Rules Coordinator at DAQ, stated that in 2014, the Utah Legislature passed House Bill 31 (H.B. 31). H.B. 31 removed the definition of "Facility" from Utah Code 19-2-102. This same definition of "Facility" was included in R307-101-2 to match the definition in the statute. Because the Legislature removed this definition from the statute, the same definition should be removed from R307-101-2. The definition of "facility" in R307-101-2 is as follows: "Facility" means machinery, equipment, structures of any part or accessories thereof, installed or acquired for the primary purpose of controlling or disposing of air pollution. It does not include an air conditioner, fan or other similar device for the comfort of personnel." This definition consistently causes confusion in permitting due

to the common understanding that “facility” is something built, installed, or established to serve a particular purpose. DAQ has identified 269 times when the term “facility” is used in throughout R307. With the exception of this definition in R307-101-2, no use of the term implies or specifically requires anything that included the control or disposal of air pollution as stated in this definition. Staff recommends that the Board propose amended rule 307-101-2 for public comment.

- Kevin Cromar moved that the Board propose amended R307-101-2, Definitions, for public comment. Arnold Reitze seconded. The Board approved unanimously.

V. Propose for Continuation: Five-Year Review of R307-101. General Requirements; R307-150. Emission Inventories; R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD); and R307-840. Lead-Based Paint Accreditation, Certification and Work Practice Standards. Presented by Thomas Gunter.

Thomas Gunter, Rules Coordinator at DAQ, stated that Utah Code 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 law. As part of this process, we are required to identify any comments received since the last five-year review of each rule. This process is not the time to revisit those comments or to respond to them. Staff has reviewed all rules listed in Section Five of the board packet and has determined that they should be continued. Staff recommends that the Board continue all listed rules by approving the attached forms to be filed with the Office of Administrative Rules.

- Arnold Reitze moved that the Board approve continuation of the five-year review of R307-101, General Requirements; R307-150, Emission Inventories; R307-405, Permits: Prevention of Significant Deterioration of Air Quality (PSD); and R307-840, Lead-Based Paint Accreditation, Certification and Work Practice Standards. William Stringer seconded. The Board approved unanimously.

VI. Informational Items.

A. Air Toxics. Presented by Robert Ford.

B. Compliance. Presented by Jay Morris and Harold Burge.

Jay Morris, Minor Source Compliance Section Manager at DAQ, clarified that major sources are inspected annually and minor sources are inspected once every three years.

C. Monitoring. Presented by Bo Call.

Bo Call, Air Monitoring Section Manager at DAQ, presented the graphs for the monitoring and answered questions regarding the spikes at various events for PM and ozone. Nucor Steel in Plymouth, Utah is running an ambient air monitoring station. DAQ is working with Nucor Steel so that DAQ can provide that data to the public.

D. Other Items to be Brought Before the Board.

Bryce Bird updated that the comment period for the Part A ended on October 31, 2018, and those comments are posted on the PM2.5 website. The Part H comment period is currently open and those comments will also be posted in early December.

E. Board Meeting Follow-up Items.

- Status on the Board's request for DAQ staff to present on the consideration of fines and the rate of inspection for sources. Staff will present this at the January 2, 2019, working lunch.
- Status on the Board's request in October for DAQ staff presentation or discussion on the development of the Inland Port.

Board members raised questions and issues, most of which cannot be answered by staff at this time. A lot of the issues are being driven by those in authority which DEQ does not have. DEQ's role is specifically to consult with the Inland Port Authority Board (IPAB) and provide information to them. Scott Baird, Deputy Director at DEQ, is the department's representative on the IPAB's technical advisory committee. As planning for the development for new rail lines, new roads, new manufacturing, etc. begins, then analysis by DEQ can begin. At a future meeting, staff will give a presentation to the Board on what DEQ is doing in preparation of the development of the Inland Port.

- Status on the Board's request in September on how staff communicates air quality to the public. Staff indicated that this is still under development and it will be presented at one of the first three meetings in the new year.

Meeting adjourned at 2:04 p.m.

ITEM 4



State of Utah

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Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-093-18

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Bill Reiss, Environmental Engineer

DATE: December 18, 2018

SUBJECT: FINAL ADOPTION: SIP Subsection IX.A.31: Control Measures for Area and Point Sources, Fine Particulate Matter, Serious Area PM_{2.5} SIP for the Salt Lake City, UT Nonattainment Area, as amended.

On December 14, 2009, EPA designated the Salt Lake City, UT PM_{2.5} Nonattainment Area. Utah was required to submit a Moderate Area nonattainment plan for the area that demonstrated either 1) attainment of the National Ambient Air Quality Standard (NAAQS) by an attainment date, established as December 31, 2015, or alternately 2) that attainment by such date was impracticable.

The Moderate Area plan submitted by Utah demonstrated the latter, and after the attainment date had arrived, EPA determined that the area did not meet the NAAQS. This finding led to a re-classification of the SLC PM_{2.5} nonattainment area from Moderate to Serious, and a new requirement for the State to submit a Serious Area State Implementation Plan (SIP) to the EPA.

A Serious Area SIP must include Best Available Controls Measures and Technologies (BACM /BACT) and a demonstration of attainment no later than 10 years after the year in which the area had been initially designated nonattainment, i.e., December 31, 2019.

The Division of Air Quality proposed its plan to address these requirements to the Board on September 5, 2018. The demonstration of attainment includes a modeled evaluation of the airshed with respect to emission reductions expected in time for 2019. It is supplemented by additional

information that comprises a weight of evidence that concludes the SLC nonattainment area will likely be able to demonstrate attainment of the 2006, 24-hour PM_{2.5} health standard by the attainment date of December 31, 2019.

The plan includes necessary elements to support the demonstration, control strategy, and implementation of the plan. These elements include emissions inventories, mobile source emission budgets, quantitative milestones which demonstrate reasonable further progress toward attainment, and contingency measures.

The BACM /BACT requirements (in Part H) for stationary point sources had been proposed already (on June 6, 2018) as an element that was “generally independent” of the attainment demonstration underlying the Serious Area SIP. Comments received on the earlier BACT requirements in Part H took issue with this stated disconnection from the broader SIP and its underlying attainment demonstration.

The point was later underscored during the proposal to release this Part A for public comment, and the Board responded by releasing, for public comment, alongside Part A.31, the original comment made in the context of Part H. This comment included a collection of modeling analyses demonstrating, for each of the PM_{2.5} Plan Precursors (NO_x, SO_x, VOC, and NH₃), that the emissions from existing major stationary sources located in the nonattainment area do not contribute significantly to PM_{2.5} levels that exceed the standard in the area.

The PM_{2.5} Implementation Rule allows that a state may elect to submit to the EPA one or more precursor demonstrations. If the State does submit such a demonstration to EPA and EPA approves the demonstration, then for the PM_{2.5} Plan Precursor(s) for which EPA has approved the demonstration, the state is not required to identify and evaluate potential control measures to reduce emissions from any existing major stationary sources.

A 30-day period of public review surrounding Part A, as well as the associated precursor demonstration comment, was held throughout the month of October. Numerous comments were received. They have been summarized and responded to in Attachment B to this memorandum. Certainly, many of the more significant comments surround the petition to incorporate the various major stationary source precursor demonstrations. Anticipating as much, DAQ had indicated it would independently evaluate the contribution made by existing major stationary sources to the PM_{2.5} levels addressed by this Serious Area SIP. DAQ’s (draft) analysis is included here as Attachment C, and informs its responses to these comments.

Additionally, Part H was re-proposed for public comment on October 3rd, and a 30-day period of public review was held for it throughout the month of November. Both Part A and Part H have been brought before the Board today for final adoption.

Most significantly, staff is recommending that Utah not elect to include any major stationary source PM_{2.5} precursor demonstration in its Serious Area SIP at this time. Furthermore, it is recommending that the emission limits and operating conditions articulated for major stationary sources in Part H not be made conditional on the approval by EPA of any such major stationary source precursor demonstration.

Staff Recommendation: Staff recommends that the Board adopt SIP Subsection IX.A.31: Control Measures for Area and Point Sources, Fine Particulate Matter, Serious Area PM_{2.5} SIP for the Salt Lake, UT Nonattainment Area, as amended.

Attachment A: Amended SIP Subsection IX. Part A.31: Control Measures for Area and Point Sources, Fine Particulate Matter, Serious Area PM_{2.5} SIP for the Salt Lake, UT Nonattainment Area.

Attachment B: Response to Comments Received During the Previous SIP Subsection IX. Part A Comment Period

Attachment C: “Draft UDAQ Major Stationary Source Precursor Demonstration for the Salt Lake City 24-hour PM_{2.5} Serious non-attainment Area”

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ATTACHMENT A

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Control Measures for Area and Point Sources, Fine Particulate Matter, Serious Area PM_{2.5} SIP for the Salt Lake City, UT Nonattainment Area

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Adopted by the Utah Air Quality Board
, 2019

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Acronyms

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2	BACT	Best Available Control Technology
3	CAA	Clean Air Act
4	CFR	Code of Federal Regulations
5	CAMx	Comprehensive Air Quality Model with Extensions
6	CTG	Control Techniques Guideline Documents
7	DAQ	Utah Division of Air Quality (also UDAQ)
8	EPA	Environmental Protection Agency
9	FRM	Federal Reference Method
10	MACT	Maximum Available Control Technology
11	MATS	Model Attainment Test Software
12	MPO	Metropolitan Planning Organization
13	MVEB	Motor Vehicle Emissions Budget
14	$\mu\text{g}/\text{m}^3$	Micrograms Per Cubic Meter
15	Micron	One Millionth of a Meter
16	NAAQS	National Ambient Air Quality Standards
17	NESHAP	National Emissions Standards for Hazardous Air Pollutants
18	NH_3	Ammonia
19	NO_x	Nitrogen Oxides
20	NSPS	New Source Performance Standard
21	NSR	New Source Review
22	PM	Particulate Matter
23	PM_{10}	Particulate Matter Smaller Than 10 Microns in Diameter
24	$\text{PM}_{2.5}$	Particulate Matter Smaller Than 2.5 Microns in Diameter
25	RACM	Reasonably Available Control Measures
26	RACT	Reasonably Available Control Technology
27	RFP	Reasonable Further Progress
28	SIP	State Implementation Plan
29	SMAT	Software for Model Attainment Test
30	SMOKE	Sparse Matrix Operator Kernel Emissions
31	SO_2	Sulfur Dioxide
32	SO_x	Sulfur Oxides
33	TSD	Technical Support Document
34	VOC	Volatile Organic Compounds
35	UAC	Utah Administrative Code
36	UWFPS	Utah Wintertime Fine Particulate Study
37	WRF	Weather Research and Forecasting

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Chapter 1 – INTRODUCTION AND BACKGROUND

1.1 Fine Particulate Matter

According to EPA's website, particulate matter, or PM, is a complex mixture of extremely small particles and liquid droplets. Particulate matter is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

The size of particles is directly linked to their potential for causing health problems. EPA is concerned about particles that are 10 micrometers in diameter or smaller because those are the particles that generally pass through the throat and nose and enter the lungs. Once inhaled, these particles can affect the heart and lungs and cause serious health effects. Other negative effects are reduced visibility and accelerated deterioration of buildings.

EPA groups particle pollution into two categories:

- "Inhalable coarse particles," such as those found near roadways and dusty industries, are larger than 2.5 micrometers and smaller than 10 micrometers in diameter. Utah has previously addressed inhalable coarse particles as part of its PM₁₀ SIPs for Salt Lake and Utah Counties, but this fraction is not measured as PM_{2.5} and will not be a subject for this nonattainment SIP.
- "Fine particles," such as those found in smoke and haze, are 2.5 micrometers in diameter and smaller and thus denoted as PM_{2.5}. These particles can be directly emitted from sources such as forest fires, or they can form when gases emitted from power plants, industries and automobiles react in the air.

PM concentration is reported in micrograms per cubic meter or $\mu\text{g}/\text{m}^3$. The particulate is collected on a filter and weighed. This weight is combined with the known amount of air that passed through the filter to determine the concentration in the air.

1.2 Health and Welfare Impacts of PM_{2.5}

Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing, for example;

- decreased lung function;
- aggravated asthma;
- development of chronic bronchitis;
- irregular heartbeat;
- nonfatal heart attacks; and
- pre-mature death in people with heart or lung disease.

People with heart or lung diseases, children and older adults are the most likely to be affected by particle pollution exposure. However, even healthy people may experience temporary symptoms from exposure to elevated levels of particle pollution.

1.3 Fine Particulate Matter in Utah

Excluding wind-blown desert dust events, wild land fires, and holiday related fireworks, elevated PM_{2.5} in Utah occurs during the winter season when certain meteorological conditions create stagnant cold pools of air.

During a winter-time cold pool episode, dispersion is very poor due to the very stable air mass and PM_{2.5} emissions become trapped in the valley. Furthermore, emissions of PM_{2.5} precursors react quickly to create secondary PM and overall concentrations of primary and secondary PM_{2.5} become elevated. Cold pool episodes persist until meteorological conditions change to once again allow for good mixing. Episodes may last from a few days to tens of days. The meteorological conditions that lead to the formation of cold pools in Utah's nonattainment areas are: synoptic scale ridging, subsidence, light winds, snow cover (often), and cool-to-cold surface temperatures. These conditions occur during winter months, generally mid-November through early March. The scenario described above leads to exceedances and violations of the 2006, 24-hour health standard for PM_{2.5}. In other parts of the year concentrations are generally low, and even with the high peaks incurred during winter, average concentrations are well within the 2013, annual health standard for PM_{2.5}.

1.4 2006 NAAQS for PM_{2.5}

In September of 2006, EPA revised the (1997) National Ambient Air Quality Standards (NAAQS) for PM_{2.5}. While the annual standard remained unchanged at 15 µg/m³, the 24-hr standard was lowered from 65 µg/m³ to 35 µg/m³.

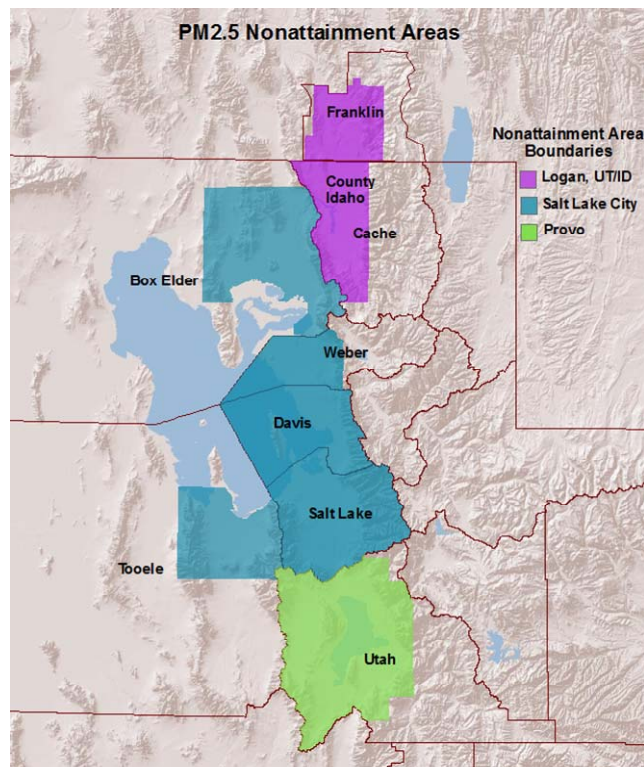
DAQ has monitored PM_{2.5} since 2000, and found that all areas within the state were in compliance with the 1997 standards. However, using the new 2006 standard as the benchmark, all or parts of five counties were found to be out of compliance with the 24-hr standard.

1 In 2013, EPA lowered the annual average to 12 $\mu\text{g}/\text{m}^3$. Monitoring data shows no
2 instances of noncompliance with this revised standard.
3
4
5

6 1.5 PM_{2.5} Nonattainment Areas in Utah

7 There are three distinct nonattainment areas for the 2006, 24-hour PM_{2.5} standard. These
8 are the Salt Lake City, UT, and Provo, UT nonattainment areas, which together
9 encompass what is referred to as the Wasatch Front. A third nonattainment area is more
10 or less geographically defined by the Cache Valley which straddles the border between
11 Utah and Idaho (the Logan, UT – ID nonattainment area.) **Figure 1.1** below shows the
12 geographic extent of these areas.

13 None of these three areas has violated the annual NAAQS for PM_{2.5}. Without exception,
14 the exceedances leading to 24-hr NAAQS violations are associated with relatively short-
15 term meteorological occurrences.



16
17 **Figure 1.1, Nonattainment Areas for the 2006, PM_{2.5} 24-hr. NAAQS**
18

Each of these three areas was effectively designated as nonattainment on Dec. 14, 2009 by the EPA (74 FR 58688) based on weights of evidence belonging to the following nine factors:

- pollutant emissions
- air quality data
- population density and degree of urbanization
- traffic and commuting patterns
- growth
- meteorology
- geography and topography
- jurisdictional boundaries
- level of control of emissions sources

EPA also used analytical tools and data such as pollution roses, fine particulate composition monitoring data, back trajectory analyses, and the contributing emission score (CES) to evaluate these areas.

1.6 Reclassification to Serious

The EPA originally designated the Salt Lake City nonattainment area under the general provisions of CAA title I, part D, subpart 1 (“subpart 1”), under which attainment plans must provide for the attainment of a specific NAAQS (in this case, the 2006 PM_{2.5} standards) as expeditiously as practicable, but no later than five years from the date the areas were designated nonattainment (December 14, 2014).

On December 11, 2013, Utah submitted a SIP that contained multiple area source rules intended to reduce emissions in the area. Subsequently, on January 4, 2013, the U.S. Court of Appeals for the District of Columbia Circuit held that the EPA should have implemented the 2006 24-hour PM_{2.5} standard based on both the general nonattainment area requirements in subpart 1 and the PM-specific requirements of CAA title I, part D, subpart 4 (“subpart 4”). Under subpart 4, PM nonattainment areas are initially classified as Moderate, and Moderate area attainment plans must address the requirements of subpart 4 as well as subpart 1. Additionally, CAA subpart 4 establishes a different SIP submittal due date and attainment year. For a Moderate PM_{2.5} nonattainment area, the attainment SIP is due no later than 18 months after designation and the attainment year is as expeditiously as practicable after designation but no later than the end of the sixth calendar year after designation (December 31, 2015).

On June 2, 2014 (79 FR 31566), the EPA finalized the Identification of Nonattainment Classification and Deadlines for Submission of State Implementation Plan (SIP) Provisions for the 1997 Fine Particulate (PM_{2.5}) NAAQS and 2006 PM_{2.5} NAAQS (“the Classification and Deadlines Rule”). This rule classified the areas that were designated in 2009 as nonattainment to Moderate, and set the attainment SIP submittal due date for those areas at December 31, 2014. This rule did not affect the Moderate area attainment date of December 31, 2015.

After the court’s decision, the Utah Department of Air Quality (UDAQ) withdrew all prior Salt Lake City, UT PM_{2.5} SIP submissions and submitted a new SIP to address both

1 the general requirements of subpart 1 and the PM-specific requirements of subpart 4 for
2 Moderate areas¹. The modeled attainment demonstration underlying the new Moderate
3 Area SIP made its assessment concerning attainment by the applicable attainment date
4 (December 31, 2015), and concluded that it would be impracticable to do so.

5 After reaching the statutory attainment date, the EPA is compelled to determine whether
6 the area has or has not achieved compliance with the standard by evaluating the prior
7 three years of quality assured data. That determination was published on May 10, 2017
8 (89 FR 21711) and concluded that the Salt Lake City nonattainment area did not reach
9 attainment of the 2006 24-hour standard by its attainment date, and would therefore be
10 effectively re-classified from a Moderate PM_{2.5} nonattainment area to a Serious PM_{2.5}
11 nonattainment area as of June 9, 2017.

12 Under subpart 4 of the CAA, Serious PM nonattainment areas require, in addition to the
13 provisions submitted to meet the Moderate area planning requirements, the submittal of a
14 SIP revision that: 1) provides for attainment of the applicable NAAQS no later than the
15 end of the 10th calendar year after the area's designation as nonattainment (December 31,
16 2019), and 2) includes provisions to assure that the Best Available Control Measures for
17 the control of PM_{2.5} shall be implemented no later than four years after the date the area
18 is re-classified as a Serious Area.

19 On August 24, 2016, the EPA finalized the Fine Particulate Matter National Ambient Air
20 Quality Standards: State Implementation Plan Requirements ("PM_{2.5} Implementation
21 Rule"), 81 FR 58010, which addressed the January 4, 2013 court ruling. The final
22 implementation rule provides the EPA's interpretation of the requirements applicable to
23 PM_{2.5} nonattainment areas and explains how air agencies can meet the statutory SIP
24 requirements that apply under subparts 1 and 4 to areas designated nonattainment for any
25 PM_{2.5} NAAQS. These statutory requirements are further addressed in Chapter 2.

26 1.7 PM_{2.5} Precursors

27 The majority of ambient PM_{2.5} collected during a typical cold-pool episode of elevated
28 concentration is secondary particulate matter, born of gaseous precursor emissions.
29 PM_{2.5} precursors include sulfur dioxide (SO₂), oxides of nitrogen (NO_x), volatile organic
30 compounds (VOC), and ammonia (NH₃).

31 Clean Air Act Section 189(e) requires that the control requirements applicable in plans
32 for major stationary sources of PM₁₀ shall also apply to major stationary sources of PM₁₀
33 precursors, except where the Administrator determines that such sources do not
34 contribute significantly to PM₁₀ levels which exceed the standard in the area.

35 The new PM_{2.5} Implementation Rule interprets this requirement as it applies to PM_{2.5}. As
36 part of this rule, a state may elect to submit one or more demonstrations to assert that
37 reducing the emission level of a particular precursor will not result in a significant benefit
38 to the area in terms of PM_{2.5} concentrations. Generally speaking, if a state elects to do so
39 and the EPA subsequently approves the demonstration, the state would not be required to
40 include emission controls for that precursor in its SIP control strategy.

¹ The Moderate Area SIP for the Salt Lake City, UT PM_{2.5} nonattainment area was adopted by the Utah Air Quality Board on December 3, 2014 and submitted to the EPA on December 22, 2014. The narrative appears in the SIP at Section IX.A.21 and the Emission Limits and Operating Practices which apply to specific stationary sources located in the nonattainment area are listed in Section IX. Part H. 11 and 12.

1 Utah has not included any such demonstration with this Serious Area SIP submittal. As
2 such, the requirement to ensure the implementation of best available control measures
3 applies to emissions of PM_{2.5} and to each of the four PM_{2.5} precursors listed above. As
4 such, each of these PM_{2.5} precursors is also defined as a PM_{2.5} plan precursor within the
5 Salt Lake City, UT PM_{2.5} nonattainment area.
6

Chapter 2 – REQUIREMENTS FOR 2006, PM_{2.5} PLAN REVISIONS

2.1 Requirements for Nonattainment SIPs

Section 110 of the Clean Air Act lists the requirements for implementation plans. Many of these requirements speak to the administration of an air program in general. Section 172 of the Act contains the plan requirements for nonattainment areas in general.

The Clean Air Act also contains provisions, at Subpart 4 of Part D, that apply specifically to PM₁₀ nonattainment areas. On January 4, 2013, D.C. Circuit Court of Appeals found that these provisions should also apply to PM_{2.5} nonattainment areas.

Under Subpart 4, nonattainment areas for particulate matter may carry the classification of either moderate or serious. Addressed therein are the attainment dates and planning provisions for both moderate and serious areas. Of note is that the planning requirements for serious areas are *in addition to* those required for moderate areas.

EPA's new PM_{2.5} Implementation Rule interprets the requirements of Subpart 4 as they apply to PM_{2.5}. In particular, this rulemaking (81 FR 58010) recodifies Subpart Z of 40 CFR Part 51 ("Provisions for Implementation of PM_{2.5} National Ambient Air Quality Standards") which had been revoked as part of the January 4, 2013 Court ruling. Subpart Z details what is required of plan revisions addressing both moderate and serious PM_{2.5} nonattainment areas.

Utah has already addressed the moderate area planning requirements in the SIP it adopted on December 3, 2014. This SIP will now address the serious area requirements as articulated in Subpart Z.

This Serious Area implementation plan was developed to meet the requirements specified in the law, rule, and appropriate guidance documents identified above. Some of the more notable requirements that pertain to this SIP include:

- A demonstration, including air quality modeling, that the plan provides for attainment of the applicable NAAQS no later than the end of the 10th calendar year after the area's designation as nonattainment (December 31, 2019)
- A comprehensive base-year inventory of actual emissions as well as a projected inventory of emissions in the attainment year
- Provisions for the implementation of Best Available Control Measures including Technologies (BACM / BACT) no later than 4 years after the date the area is re-classified as a Serious Area
- Enforceable emission limits as well as schedules for compliance
- Transportation Conformity, including motor vehicle emission budgets
- Quantitative Milestones that demonstrate Reasonable Further Progress (RFP) toward attainment of the National Ambient Air Quality Standards by the applicable attainment date
- Contingency measures to be undertaken if the area fails to make reasonable further progress or attain the NAAQS by the applicable attainment date

- 1 Additional information is provided in the technical support document (TSD).
- 2

1 Chapter 3 – Ambient Air Quality Data

2 3.1 Measuring Fine Particle Pollution in the Atmosphere

3 Utah has monitored PM_{2.5} in its airsheds since 2000, following the promulgation of the
4 1997, PM_{2.5} NAAQS which was set at 65 µg/m³ for a 24-hour averaging period. PM_{2.5}
5 concentrations, especially during Utah's wintertime cold pool episodes, tend to be
6 regionally homogenous within a specific airshed. This means that just a few monitors
7 can adequately determine compliance with the NAAQS for these airsheds. UDAQ's
8 monitors are appropriately located to assess concentration, trends, and changes in PM_{2.5}
9 concentrations. During Utah's wintertime temperature inversions, every day sampling
10 and real time monitoring are needed public notification and for subsequent air quality
11 modeling.

12 3.2 Utah's Air Monitoring Network

13 The Air Monitoring Section maintains an ambient air monitoring network in Utah that
14 collects both air quality and meteorological data. **Figure 3.1** shows the location of sites
15 along the Wasatch Front and in the Cache Valley that collect PM_{2.5} data.
16 Data collected at three of the sites along the Wasatch Front is analyzed to determine the
17 various species of PM_{2.5} that collectively make up the total mass. Particulate matter
18 collected on the speciation filters is analyzed for organic and inorganic carbon and a list
19 of 48 elements. PM_{2.5} speciation data is particularly useful in helping to identify sources
20 of particulate matter.
21 The ambient air quality monitoring network along Utah's Wasatch Front and in the
22 Cache Valley is routinely audited by the EPA, and meets the agency's requirements for
23 air monitoring networks.

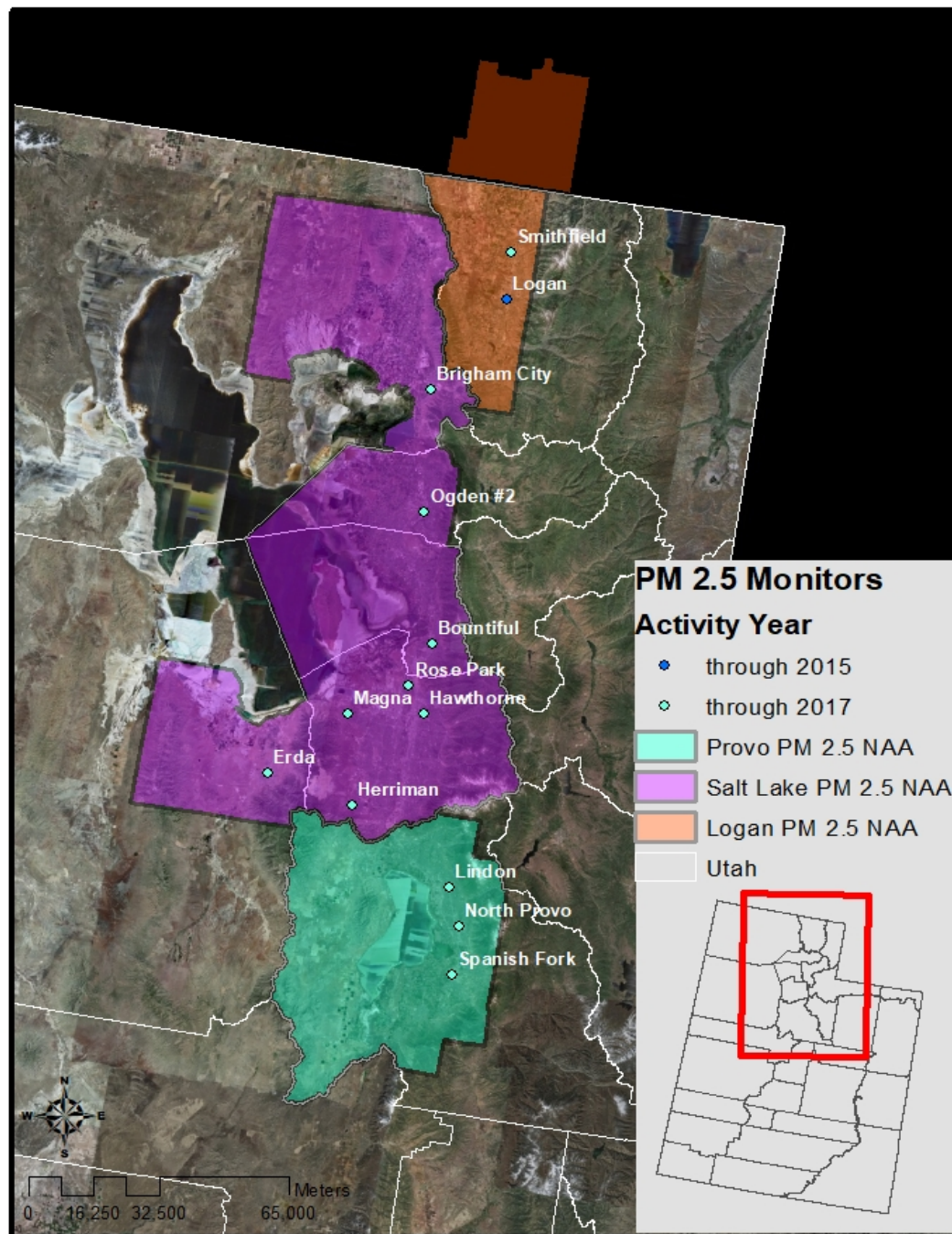


Figure 3.1, Utah's PM_{2.5} Air Monitoring Network

3.3 Data Handling

PM_{2.5} collected on filter media must be weighed and calibrated in order that a concentration may be determined for a 24-hour period. Once determined, the data is entered into a database maintained by the EPA (called AQS). In order to be used for regulatory purposes, data determined from filters must include verification that it was handled in accordance with certain quality assurance specifications; among these are appropriate ranges of temperature and relative humidity (RH) within which the processing must take place. A routine audit of Utah's air quality data collected from 2013 - 2015 identified numerous instances for which the temperature and RH parameters were either not recorded at all or were recorded outside of their specified range. It appeared, therefore, that this data could not be used for regulatory purposes. Particularly important was data collected in 2015, one of the years used to construct a monitored design value for this SIP.

The form of the PM_{2.5} NAAQS takes into consideration the percentage of data captured throughout each calendar quarter. There is a general expectation that at least 75% of the data scheduled for collection will actually be captured. The degree of data capture affects what value will be entered into the AQS database for comparison with the NAAQS. If data capture is poor, a higher more conservative value will be selected for use, particularly with respect to the 24-hour value denoted as the 98th percentile.

Further investigation into the suspect temperature and RH values identified the problem as a software error that affected the recording of the values measured by the filter robot rather than the values themselves. Data handling procedures allow for the substitution of temperature and RH data from other sources, and by substituting the temperature and RH data from instruments situated in the room within which the filter robot operates, UDAQ has been able to recover most of the suspect filter data from 2015. The entire problem had been rectified by 2016.

The number of filters recovered from the 2015 data record sits at four or five hundred. Priority was given to those filters that most directly affected this SIP. Still, there are more filters that UDAQ would like to recover, and this work will continue for some time after this SIP has been completed. This means that there will continue to be some discrepancies between the PM_{2.5} values reported herein and the values one may access in the AQS database. In order that a filter becomes fully recovered, EPA must remove a (null) code associated with each filter record.

Another reason the PM_{2.5} values reported in this SIP may not match the values appearing in AQS concerns data flagged by UDAQ resulting from an exceptional event. Until EPA affixes a second flag indicating that it has concurred with UDAQ's assertion, the data will be considered useful for regulatory purposes. This will be discussed further in Chapter 6.

3.4 Annual PM_{2.5} – Mean Concentrations

The procedure for evaluating PM_{2.5} data with respect to the NAAQS is specified in Appendix N to 40 CFR Part 50. Generally speaking, the annual PM_{2.5} standard is met when a three-year average of annual mean values is less than or equal to 12.0 µg/m³. Each annual mean is itself an average of four quarterly averages.

Table 3.1, below shows the mean values for 2015, 2016, and 2017. These are the years surrounding 2016, the year for which the baseline modeling inventory was prepared. It also shows the 3-year average of those values, as a comparison against the NAAQS for each of Utah's monitoring locations. All locations are in compliance with the annual NAAQS.

Location	County	Annual Mean Values (µg/m ³)			3-Yr Average (µg/m ³)
		2015	2016	2017	
Logan	Cache	7.3			7.3
Smithfield	Cache	5.5	7.6	7.9	7.0
Brigham City	Box Elder	5.6	7.4	8.5	7.1
Ogden 2	Weber	9.7	9	7.3	8.6
Bountiful	Davis	6.5	8	9	7.8
Magna	Salt Lake	7.1	7.1	7.3	7.1
Hawthorne	Salt Lake	7.4	7.9	8.2	7.8
Rose Park	Salt Lake	8.7	9.4	7.8	8.6
Herriman 3	Salt Lake		4.6	5.7	5.1
Erda	Tooele		6.3	6.5	6.4
North Provo	Utah	7	8.2	5	6.7
Lindon	Utah	7.4	8.8	8.4	8.2
Spanish Fork	Utah	6.5	7.4	7.3	7.0

Table 3.1, PM_{2.5} Annual Mean Concentrations

3.5 24-hour PM_{2.5} – Averages of 98th Percentiles and Monitored Design Values

The procedure for evaluating PM_{2.5} data with respect to the NAAQS is specified in Appendix N to 40 CFR Part 50. Generally speaking, the 24-hr. PM_{2.5} standard is met when a 3-year average of 98th percentile values is less than or equal to 35 µg/m³. Each year's 98th percentile is the daily value beneath which 98% of all daily values would fall. Table 3.2, below shows the 98th percentile values for 2015, 2016, and 2017. These are the years surrounding 2016, the year for which the baseline modeling inventory was prepared. It also shows the 3-year average of those values, as a comparison against the NAAQS for each of Utah's monitoring locations. It can be seen from the data that the 24-hr. NAAQS is violated at the Rose Park monitoring location. This SIP has been structured to specifically address the 24-hr. standard.

It is important to note that the data in **Tables 3.1 and 3.2** excludes several values from 2017, at certain stations, that were flagged by UDAQ as having been affected by wildland fire or fireworks. UDAQ expects that EPA will eventually concur with UDAQ's flags,

thereby excluding them from regulatory use. Two such values were measured at Rose Park, and would therefore affect the 98th percentile value for that year. No exceptional events were flagged at the Hawthorne site. EPA has indicated to UDAQ that it is appropriate to exclude these values from the design values calculated in this SIP.

Location	County	98th Percentile Values (µg/m3)			3-Yr Average (µg/m3)
		2015	2016	2017	
Logan	Cache	29.0			29.0
Smithfield	Cache	28.9	34.0	36.0	32.9
Brigham City	Box Elder	26.7	34.8	34.4	31.9
Ogden 2	Weber	32.9	39.0	25.3	32.4
Bountiful	Davis	29.2	24.7	35.2	29.7
Magna	Salt Lake	22.9	30.7	30.1	27.9
Hawthorne	Salt Lake	28.8	38.4	35.7	34.3
Rose Park	Salt Lake	33.3	43.2	32.4	36.3
Herriman 3	Salt Lake		24.9	28.2	26.5
Erda	Tooele		25.1	20.5	22.8
North Provo	Utah	25.0	36.6	21.9	27.8
Lindon	Utah	27.3	36.3	27.6	30.4
Spanish Fork	Utah	28.1	29.2	27.6	28.3

Table 3.2, 24-hour PM_{2.5} Monitored Design Values

As mentioned in the foregoing paragraph, this SIP is structured to address the 24-hr. PM_{2.5} NAAQS. EPA's modeling guidance² prescribes a modeled attainment test that includes a monitored baseline design value for each monitoring location. It notes that the design values should be consistent with the form of the applicable NAAQS. The 24-hour PM_{2.5} NAAQS is based on a 3-year average of 98th percentile values. The modeling guidance suggests several possible methodologies to calculate baseline design values, including a 3-year average that coincides with the years used to designate the area to nonattainment as well as a 3-year average that straddles the baseline inventory year. In this case, the area was designated as nonattainment in 2006, too long ago for those years to still be considered representative. However, the three years used to construct the design values (2015 – 2017) straddle the baseline inventory year (2016) and include 2015, one of the years used to reclassify the area from moderate to serious.

² Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM_{2.5}, and Regional Haze (EPA -454B-07-002, April 2007)

3.6 Composition of Fine Particle Pollution – Speciated Monitoring Data

DAQ operates three PM_{2.5} speciation sites. The Hawthorne site in Salt Lake County is one of 52 Chemical Speciation Network sites (CSN) operated nationwide on an every-third-day sampling schedule. Sites at Bountiful/Viewmont in Davis County and Lindon in Utah County are State and Local Air Monitoring Stations (SLAMS) PM_{2.5} speciation sites that operate on an every-sixth-day sampling schedule.

Filters are prepared by the EPA contract laboratory and shipped to Utah for sampling. Samples are collected for particulate mass, elemental analysis, identification of major cations and anions, and concentrations of elemental and organic carbon as well as crustal material present in PM_{2.5}. Carbon sampling and analysis changed in 2007 to match the Interagency Monitoring of Protected Visual Environments (IMPROVE) method using a modified IMPROVE sampler at all sites.

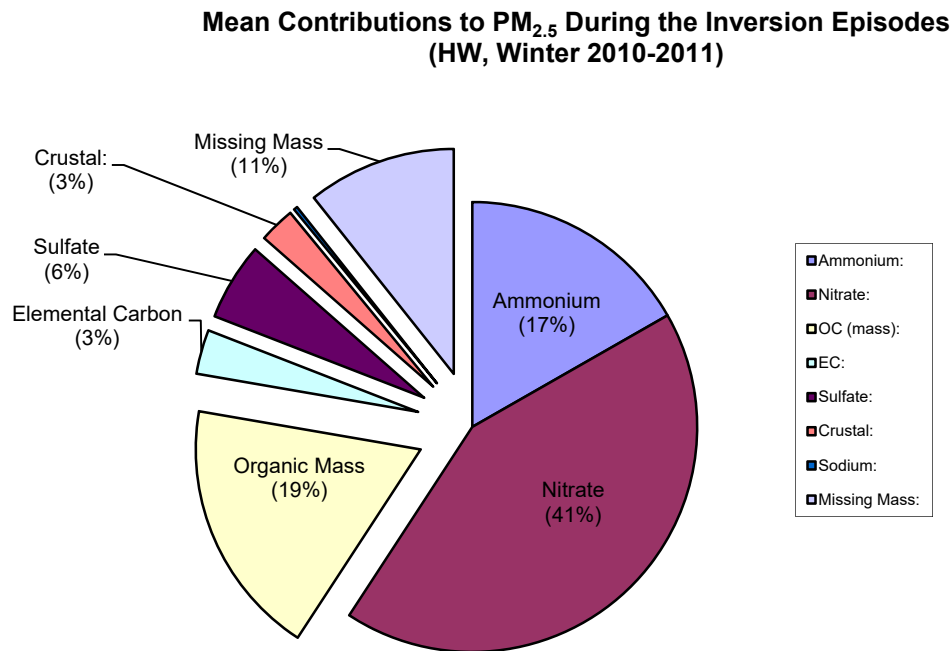
The PM_{2.5} is collected on three types of filters: Teflon, nylon, and quartz. Teflon filters are used to characterize the elemental content of PM_{2.5}. Nylon filters are used to quantify the amount of major inorganic ions, and quartz filters are used to quantify the organic and elemental carbon content in the ambient PM_{2.5}.

Data from the speciation network show the importance of volatile secondary particulates, particularly ammonium nitrate, during the colder months. A significant number of these particles are lost in FRM PM_{2.5} sampling.

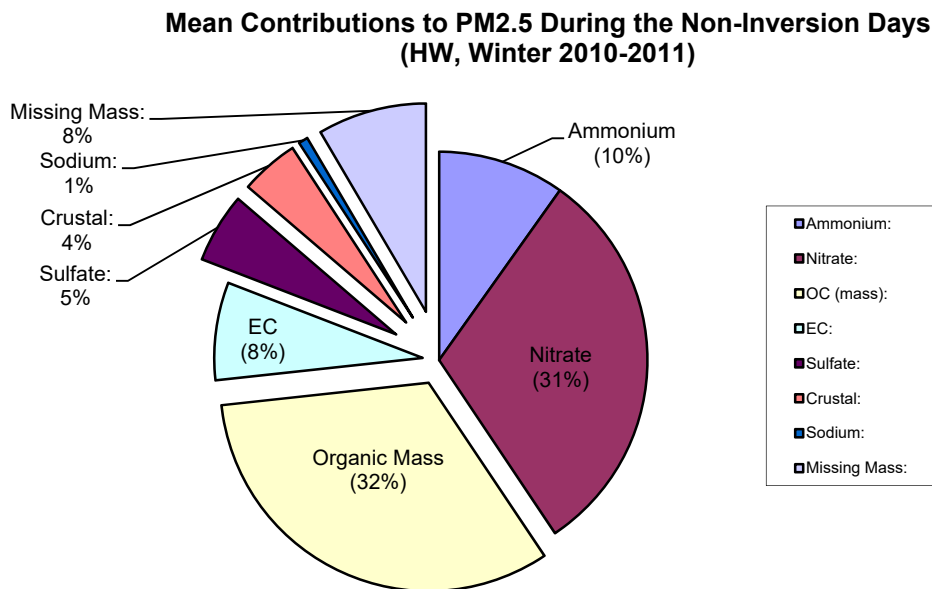
During the winter periods between 2009 and 2011, UDAQ conducted special winter speciation studies aimed at better characterization of PM_{2.5} during the high pollution episodes. These studies were accomplished by shifting the sampling of the Chemical Speciation Network monitors to 1-in-2-day schedule during the months of January and February. Speciation monitoring during the winter high-pollution episodes produced similar results in PM_{2.5} composition each year.

The results of the speciation studies led to the conclusion that the exceedances of the PM_{2.5} NAAQS are a result of the increased portion of the secondary PM_{2.5}, mainly ammonium nitrate, that was chemically formed in the air and not primary PM_{2.5} emitted directly into the troposphere.

1 **Figure 3.2** below shows the contribution of the identified compounds from the speciation
 2 sampler both during a winter temperature inversion period and during a well-mixed
 3 winter period.
 4



5



6

7 **Figure 3.2, Composite Wintertime PM_{2.5} Speciation Profiles**

3.7 Utah Winter Fine Particulate Study (UWFPS)

The Utah Winter Fine Particulate Study aimed to address the scientific uncertainties surrounding winter $PM_{2.5}$ pollution. The study took place during the winter of 2017, during which NOAA's specially equipped light aircraft known as the Twin Otter flew over the Cache, Salt Lake, and Utah valleys to survey the chemical conditions responsible for the formation of $PM_{2.5}$. This study was a collaborative project between scientists from the Division of Air Quality, the National Oceanic and Atmospheric Administration (NOAA) Earth System Research Laboratory (ESRL) and the Cooperative Institute for Research in Environmental Sciences (CIRES), University of Colorado Boulder, the Environmental Protection Agency (EPA), United States Department of Agriculture (USDA), University of Utah, University of Washington, University of Toronto, University of Minnesota, Utah State University, and Brigham Young University. The survey looked to investigate the chemistry, transport, and spatial and vertical distribution of species relevant to particulate formation. Seven multi-day pollution episodes with elevated $PM_{2.5}$ were observed during 2016 – 2017 winter. Two dominating episodes with multiple NAAQS exceedances occurred during the UWFPS period, providing an opportunity to study the chemical and meteorological conditions during and outside pollution episodes in different environments and examine the temporal, spatial, and vertical variability of chemical conditions. Consistent with prior studies ammonium nitrate was found to dominate the $PM_{2.5}$ mass. One of the main questions with respect to ammonium nitrate is the attribution of the limiting reagents in each of the three valleys. The study found that Cache Valley is nitrate limited, while Salt Lake and Utah Valleys are predominately nitrate limited, but also may have periods where they are ammonium limited. Salt Lake Valley is the least nitrate limited and often is ammonium limited later in a persistent cold air pool episode. Additionally, during the study high time resolution ammonia measurements were taken aboard the Twin Otter in Cache Valley, and some limited continuous ammonia measurements were taken along the Wasatch Front. Passive ammonia measurements were also collected in all three valleys in Utah. Ammonia concentrations were generally found to be much higher in the Cache valley compared to the Wasatch Front, and ammonia levels in the Salt Lake Valley were on average lower than in Utah Valley. This high level of spatial variability is in disagreement with the current inventory which shows comparable inventories for Cache, Utah, and Salt Lake Counties, indicating a potential misrepresentation of ammonia sources in the inventory. These same spatial discrepancies were not seen for the nitrogen oxide emissions inventory³. While limited, VOCs and halogens measurements were also collected during this study. These measurements highlighted the important role of VOCs and halogens in wintertime $PM_{2.5}$ formation and provided information on their potential sources. VOCs and halogens, particularly nitryl

³Baasandorj, M., Brown, S., Hoch, S., Crosman, E., Long, R., Silva, P., . . . Eatough, D. (2018). 2017 Utah Winter Fine Particulate Study Final Report. Retrieved from <https://documents.deq.utah.gov/air-quality/planning/technical-analysis/research/northern-utah-airpollution/utah-winter-fine-particulate-study/DAQ-2018-004037.pdf>

1 chloride (ClNO_2), act as radical sources important for the photochemical production of
2 $\text{PM}_{2.5}$.
3 The chemical pathway where ClNO_2 is formed through the heterogeneous uptake of N_2O_5
4 on chloride-containing particles is also particularly active in the Salt Lake Valley. HCl
5 also plays an important role in $\text{PM}_{2.5}$ formation. In the presence of excess ammonia, HCl
6 will partition to aerosol particles forming ammonium chloride, with ammonium chloride
7 accounting for up to 15% of $\text{PM}_{2.5}$ mass during high wintertime $\text{PM}_{2.5}$ pollution
8 episodes⁴.
9 While the UWFPs has shed light on many questions surrounding $\text{PM}_{2.5}$ formation,
10 continued research and further analysis of the collected data is needed to reach more
11 definitive findings regarding sources and processes leading to winter fine particulate
12 matter in northern Utah and elsewhere.
13
14
15

⁴Kelly, K.E., R. Kotchenruther, R. Kuprov, and G.D. Silcox, Receptor model source attributions for Utah's Salt Lake City airshed and the impacts of wintertime secondary ammonium nitrate and ammonium chloride aerosol. *Journal of the Air & Waste Management Association*, 2013. 63(5): p. 575-590.

Chapter 4 – EMISSION INVENTORY DATA

4.1 Introduction

The emissions inventory is one means used by the state to assess the level of pollutants and precursors released into the air from various sources. The methods by which emissions inventories are collected and calculated are constantly improving in response to better analysis and more comprehensive rules. The inventories underlying this SIP were compiled using the best information available.

The sources of emissions that were inventoried may be discussed as belonging to four general categories: industrial point sources; on-road mobile sources; off-road mobile sources; and area sources which represent a collection of smaller, more numerous point sources, residential activities such as home heating, and in some cases biogenic emissions.

This SIP is concerned with PM_{2.5}, both primary in its origin and secondary, referring to its formation removed in time and space from the point of origin for certain precursor gasses. Hence, the pollutants of concern for inventory development purposes included PM_{2.5}, SO₂, NO_x, VOC, and NH₃.

On-road mobile sources are inventoried using EPA's MOVES2014a model, in conjunction with information generated by travel demand models such as vehicle speeds and miles traveled. The inventory information is calculated in units of tons per day, adjusted for winter conditions. Emissions from the other three categories are calculated in terms of tons per year.

Prior to use in the air quality model, the emissions are pre-processed to account for the seasonality of Utah's difficulty with secondary PM_{2.5} formation during winter months. These temporal adjustments also account for daily and weekly activity patterns that affect the generation of these emissions.

EPA's PM_{2.5} Implementation Rule requires that the emission values shall be either: annual total emissions, average-season-day, or both, as appropriate for the relevant PM_{2.5} NAAQS.

Utah's long-running difficulties with fine PM may be characterized as a short-term (24-hour NAAQS) problem belonging to the winter months when meteorological conditions are conducive to the both the trapping of air in the valleys due to temperature inversions and to the secondary formation of PM_{2.5}. SIP analyses inventories have historically been adjusted to reflect this seasonality.

"Average-season-day emissions" are defined, in 40 CFR 51.1000, as the sum of all emissions during the applicable season divided by the number of days in that season. Again, Utah's inventory is compiled using a variety of different averaging periods. The inventory is then gridded into the air model, using a pre-processor called SMOKE, along with an hourly temporal component for each 24 hour period. Emissions may then be extracted from SMOKE and reported in consistent time averaged units of "tons-per-day". Each projection of the emissions inventory will be modeled with meteorology reflecting the actual episode used to validate the air quality model. This episode, spanning 11 days, was incurred from Friday, December 31 through Monday, January 10, 2011.

1 Thus, Utah's SIP will report, in its narrative, average-season-day emissions, with the
2 definition of season spanning the 2011 episode. Original EI calculations will be included
3 as part of the Technical Support Document (TSD).

4 There are various time horizons that are significant to the development of this SIP. It is
5 first necessary to look at actual emissions incurred during past episodes of elevated PM_{2.5}
6 concentrations in order to develop the air quality model. The episodes studied as part of
7 the SIP occurred in 2011, 2013, and 2016. It is then necessary to look several years into
8 the future when developing emission control strategies. The significant time horizon for
9 this plan relates to the statutory attainment date, December 31, 2019. A projected
10 inventory is prepared for 2019 and then compared with a baseline inventory that is
11 contemporaneous with the monitored design values discussed in Section 3.4. In this case
12 the baseline is represented by the year 2016. In addition, it will be necessary to evaluate
13 progress towards attainment by looking at specific milestone years. In this case there are
14 two significant mileposts; 2017 and 2020. Inventories must be prepared to evaluate all of
15 these time horizons.

16 4.2 The 2014 Emissions Inventory

17 The forgoing paragraph identified numerous points in time for which an understanding of
18 emissions to the air is important to plan development. The basis for each of these
19 assessments was the 2014 tri-annual inventory. This inventory represented, at the time it
20 was selected for use, the most recent comprehensive inventory compiled by UDAQ. In
21 addition to the large major point sources that are required to report emissions every year,
22 the tri-annual inventories consider emissions from many more, smaller point sources.
23 These inventories are collected in accordance with state and federal rules that ensure
24 proper methods and comprehensive quality assurance.

25 Thus, to develop other inventories for each of the years discussed above, the 2014
26 inventory was either back-cast and adjusted for certain episodic conditions, or forecast to
27 represent more typical conditions.

28 4.3 Geographic Area: Nonattainment Areas and Modeling 29 Domain

30 As said at the outset, an emissions inventory provides a means to assess the level of
31 pollutants and precursors released into the air from various sources. This in turn allows
32 for an overall assessment of a particular airshed.

33 The modeling analysis used to support this SIP considers a regional domain that
34 encompasses three distinct airsheds belonging to three distinct PM_{2.5} nonattainment areas;
35 The Cache Valley (the Logan UT/ID nonattainment area), the central Wasatch Front (Salt
36 Lake City, UT nonattainment area), and the southern Wasatch Front (Provo, UT
37 nonattainment area).

38 Within each nonattainment area greater attention will be given to the accuracy of the
39 inventories. For example, point sources will be included at a threshold of 70 tons per
40 year inside these areas, while outside the threshold will be 100 tpy. On-road mobile

1 source emissions will make use of travel demand models in the nonattainment areas to
2 make projections of Vehicle Miles Traveled. This is not possible in the outlying areas.
3 The actual modeling domain will encompass a much greater geographical area to ensure
4 that all pollutants, including short-range transported pollutants, are included in the
5 modeling process. This additional area encompasses the remaining 22 counties in Utah
6 and some additional areas in Nevada, Arizona, New Mexico, Colorado, Wyoming, and
7 Idaho. See **Figure 6.1 in Chapter 6**.

8 In some ways, these outlying areas will be inventoried at a lesser level of detail than the
9 non-attainment areas. UDAQ will compile information directly for all areas of the state.
10 By source category, this includes Point Sources, Area Sources, and Mobile Sources (both
11 on-road and off). By contrast, UDAQ will import National Emissions Inventory (NEI)
12 data from the EPA's website to fill in the outlying areas in other states.

13 The inventories developed for each of these three areas illustrate many similarities but
14 also a few notable differences. All three areas are more or less dominated by a
15 combination of on-road mobile and area sources. However, emissions from large point
16 sources are non-existent in the Cache Valley. These emissions are mostly situated along
17 the Wasatch Front, and primarily exhibited in the Salt Lake City nonattainment area.
18 Conversely, most of the agricultural emissions are located in the Cache Valley.
19

Table 4.1 is specific to the Salt Lake City, UT nonattainment area, and shows actual emissions for the baseline year (2016), as well as projected emissions for the attainment year (2019), and each of two “milestone years” (2017 and 2020). All projections incorporate assumptions concerning growth in population and vehicle miles traveled. They also include the effects of emissions control strategies that are either already promulgated or will be required as part of the SIP. Emissions modeled for the remainder of the modeling domain are contained in the Technical Support Document.

Emissions [tons/day]	Sector	PM2.5	NOx	VOC	NH3	SO2
2016 Base Year	Area Sources	6.13	13.63	45.96	14.22	0.17
	Mobile Sources	4.98	55.38	31.84	1.29	0.41
	NonRoad Sources	1.01	16.41	8.70	0.02	0.32
	Point Sources	3.26	18.18	5.25	0.44	4.70
	Total	15.38	103.61	91.74	15.97	5.60
2017 Milestone Year	Area Sources	6.19	13.57	46.02	14.21	0.22
	Mobile Sources	5.02	52.53	30.87	1.30	0.43
	NonRoad Sources	0.96	15.77	8.47	0.02	0.33
	Point Sources	3.58	18.32	6.13	0.44	4.61
	Total	15.75	100.18	91.48	15.97	5.59
2019 Attainment Year	Area Sources	6.23	11.84	44.34	14.21	0.22
	Mobile Sources	4.78	44.02	27.26	1.25	0.43
	NonRoad Sources	0.88	15.18	9.01	0.02	0.35
	Point Sources	4.25	23.86	6.21	0.48	3.90
	Total	16.13	94.90	86.82	15.96	4.89
2020 Milestone Year	Area Sources	6.24	9.54	43.73	14.20	0.20
	Mobile Sources	4.68	40.38	25.42	1.23	0.42
	NonRoad Sources	0.82	14.08	8.10	0.02	0.36
	Point Sources	4.26	23.86	6.22	0.49	3.90
	Total	16.00	87.86	83.47	15.94	4.88

Table 4.1, Emissions Summaries for the Salt Lake City, UT PM_{2.5} Nonattainment Area; Baseline, Milestone and Attainment Years (SMOKE). Emissions are presented in tons per average-episode-day.

All estimates are calculated from the Sparse Matrix Operator Kernel Model (SMOKE) and presented in units of tons per average-episode-day. More detailed inventory information may be found in the Technical Support Document (TSD).

Table 4.2 is specific to the point sources located within the Salt Lake, UT nonattainment area, and shows actual emissions for the baseline year (2016), as well as projected emissions for the attainment year (2019), and each of two “milestone years” (2017 and 2020). All projections incorporate assumptions concerning growth and also include the effects of emissions control strategies that are either already promulgated or will be required as part of the SIP.

Site Name	2016 Emissions					2017 Emissions				
	PM _{2.5} (tons/yr)	SO _x (tons/yr)	NO _x (tons/yr)	VOC (tons/yr)	NH ₃ (tons/yr)	PM _{2.5} (tons/yr)	SO _x (tons/yr)	NO _x (tons/yr)	VOC (tons/yr)	NH ₃ (tons/yr)
*ACH Foam Technologies	0.05	0.00	0.67	75.82	0.00	0.05	0.00	0.67	75.82	0.00
ATK Launch Systems - Promontory	19.13	1.86	44.84	31.18	0.44	19.13	1.86	44.84	31.18	0.44
Big West Oil - Flying J Refinery	10.64	43.14	92.31	307.37	4.37	10.64	43.14	92.31	307.37	4.37
*Bimbo Bakeries USA Salt Lake City Plant	0.20	0.02	2.64	79.44	0.08	0.20	0.02	2.64	79.44	0.08
*Brigham Young University- Main Campus	3.35	117.92	151.21	5.07	0.54	3.35	117.92	151.21	5.07	0.54
Chevron Products Co - Salt Lake Refinery	33.99	23.62	260.87	304.98	8.90	33.99	23.62	260.87	304.98	8.90
Compass Minerals Ogden Inc. - Production Plant	80.50	9.81	134.50	72.82	3.61	80.50	9.81	134.50	72.82	3.61
*Geneva Nitrogen Inc.- Geneva Nitrogen Plant	28.28	0.00	109.14	0.02	2.70					
Hexcel Corporation- Salt Lake Operations	72.96	37.80	169.38	163.81	84.98	70.99	42.42	175.58	161.43	85.53
Hill Air Force Base - Main Base	8.45	4.01	151.42	126.36	1.45	26.10	34.14	283.95	306.86	1.45
Holly Corp- HRMC and HEP Woods Cross Operations	13.27	109.96	181.71	157.86	17.82	13.27	109.96	181.71	157.86	17.82
Kennecott Utah Copper LLC- Mine & Copperton Concentrator	274.05	1.99	4,199.63	213.70	1.75	274.05	1.99	4,199.63	213.70	1.75
Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	71.78	1,500.34	1,322.52	8.21	0.24	49.90	914.68	652.45	6.17	0.17
Kennecott Utah Copper LLC- Smelter & Refinery	421.19	704.35	160.21	10.37	5.62	421.19	704.35	160.21	10.37	5.62
Lhoist North America - Grantsville Plant	0.25	0.02	0.21	0.14	0.00	0.25	0.02	0.21	0.14	0.00
McWane Ductile - Utah	13.34	3.90	38.60	29.55	0.50	13.34	3.90	38.60	29.55	0.50
Nucor Steel- Nucor Steel	37.47	135.01	156.77	31.72	1.92	33.27	85.63	200.09	36.46	2.11
PacificCorp Energy- Gadsby Power Plant	16.86	1.52	117.39	9.57	13.15	16.86	1.52	117.39	9.57	13.15
PacificCorp Energy- Lake Side Power Plant	58.39	10.58	246.67	38.59	152.04	58.39	10.58	246.67	38.59	152.04
Procter and Gamble-Paper Manufacturing Plant	38.94	0.30	27.23	18.58	0.17	150.15	1.45	124.86	162.37	0.17
*Snowbird Development Corporation	3.52	1.48	93.33	12.11	0.64	3.52	1.48	93.33	12.11	0.64
Tesoro Refining & Marketing Company LLC	89.35	544.38	360.09	249.28	3.77	89.35	544.38	360.09	249.28	3.77
University of Utah- University of Utah facilities	15.28	0.80	73.25	10.49	3.38	15.23	0.80	73.04	10.46	3.37
Utah Municipal Power Agency - West Valley Power Plant	3.94	0.36	8.55	1.25	0.00	3.94	0.36	8.55	1.25	0.00
Vulcraft - Division of Nucor Corporation- Steel Products Manufacturing	9.68	0.50	6.68	44.91	0.04	9.87	0.53	7.10	48.29	0.04
*Wasatch Integrated Waste Mgt District- County Landfill & Energy Recovery Facility (DCERF)	9.79	17.16	236.44	23.18	0.00					
Total =	1,334.65	3,270.83	8,346.25	2,026.36	308.12	1,397.53	2,654.57	7,610.50	2,331.13	306.09

Site Name	2019 Emissions					2020 Emissions				
	PM _{2.5} (tons/yr)	SO _x (tons/yr)	NO _x (tons/yr)	VOC (tons/yr)	NH ₃ (tons/yr)	PM _{2.5} (tons/yr)	SO _x (tons/yr)	NO _x (tons/yr)	VOC (tons/yr)	NH ₃ (tons/yr)
*ACH Foam Technologies										
ATK Launch Systems - Promontory	19.13	1.86	44.84	31.18	0.44	19.13	1.86	44.84	31.18	0.44
Big West Oil - Flying J Refinery	10.64	43.14	92.32	291.97	4.37	10.64	43.14	92.32	291.97	4.37
*Bimbo Bakeries USA Salt Lake City Plant										
*Brigham Young University- Main Campus										
Chevron Products Co - Salt Lake Refinery	33.99	23.62	260.87	304.98	8.90	33.99	23.62	260.87	304.98	8.90
Compass Minerals Ogden Inc. - Production Plant	80.50	9.81	137.90	82.29	3.61	80.50	9.81	137.90	82.29	3.61
*Geneva Nitrogen Inc.- Geneva Nitrogen Plant										
Hexcel Corporation- Salt Lake Operations	77.09	50.15	188.81	171.86	92.65	78.15	50.31	186.51	174.97	93.82
Hill Air Force Base - Main Base	26.10	34.14	283.95	306.86	1.45	26.10	34.14	283.95	306.86	1.45
Holly Corp- HRMC and HEP Woods Cross Operations	13.27	109.96	181.71	157.86	17.82	13.27	109.96	181.71	157.86	17.82
Kennecott Utah Copper LLC- Mine & Copperton Concentrator	411.25	6.60	6,178.81	316.45	2.65	411.25	6.60	6,178.81	316.45	2.65
Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment	165.61	1,344.13	1,039.39	33.80	1.56	165.61	1,344.13	1,039.39	33.80	1.56
Kennecott Utah Copper LLC- Smelter & Refinery	443.16	863.74	208.34	12.49	9.75	443.16	863.74	208.34	12.49	9.75
Lhoist North America - Grantsville Plant	0.25	0.02	0.21	0.14	0.00	0.25	0.02	0.21	0.14	0.00
McWane Ductile - Utah	13.34	3.90	38.60	29.55	0.50	13.34	3.90	38.60	29.55	0.50
Nucor Steel- Nucor Steel	33.87	93.59	214.04	39.50	2.32	33.87	93.59	214.04	39.50	2.32
PacificCorp Energy- Gadsby Power Plant	16.86	1.52	117.39	9.57	13.15	16.86	1.52	117.39	9.57	13.15
PacificCorp Energy- Lake Side Power Plant	58.39	10.58	246.67	38.59	152.04	58.39	10.58	246.67	38.59	152.04
Procter and Gamble-Paper Manufacturing Plant	150.15	1.45	124.86	162.37	0.17	150.15	1.45	124.86	162.37	0.17
*Snowbird Development Corporation										
Tesoro Refining & Marketing Company LLC	91.38	91.20	275.00	268.63	3.77	91.38	91.20	275.00	268.63	3.77
University of Utah- University of Utah facilities	15.64	0.87	60.36	10.92	3.45	17.46	0.89	61.66	11.15	3.52
Utah Municipal Power Agency - West Valley Power Plant	3.94	0.36	8.55	1.25	0.00	3.94	0.36	8.55	1.25	0.00
Vulcraft - Division of Nucor Corporation- Steel Products Manufacturing	13.94	0.77	10.56	69.86	0.07	13.94	0.77	10.56	69.86	0.07
*Wasatch Integrated Waste Mgt District- County Landfill & Energy Recovery Facility (DCERF)										
Total =	1,678.50	2,691.42	9,713.18	2,340.11	318.66	1,681.37	2,691.60	9,712.18	2,343.45	319.90

Table 4.2 Emissions from Point Sources

Chapter 5 – PROVISIONS TO ENSURE BEST AVAILABLE CONTROL MEASURES

5.1 Introduction

This chapter summarizes the requirement for a Serious Area plan revision to ensure the implementation of best available control measures (BACM) no later than four years after reclassification. Additional detail concerning the assessment of specific emission control measures is contained in the Technical Support Document.

BACM is defined as any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after the date of reclassification (to Serious) and that generally can achieve greater permanent and enforceable emissions reductions ... than can be achieved through the implementation of reasonable available control measures (RACM) on the same sources. BACM includes best available control technology (BACT).

The requirement to ensure BACM/BACT sits in addition to the requirements from the Moderate Area SIP, which included RACM/RACT. Utah addressed this requirement in its Moderate Area SIP⁵ (submitted December 22, 2014).

Unlike the RACM required as part of the Moderate Area SIP, BACM/BACT is regarded by EPA as “generally independent” of attainment. This interpretation maintains the policy expressed in the Addendum ~~[to the implementation rule]~~ for PM₁₀ that BACM/BACT is to be determined without regard to the specific attainment demonstration for the area. Essentially, this means that if a control measure is determined to meet the definition of best available control measure or technology, it may not be disregarded simply because the demonstration of attainment might conclude that such measure would not be necessary to meet the NAAQS as expeditiously as practicable.

The BACM/BACT requirement for Serious PM_{2.5} nonattainment areas also applies to PM_{2.5} precursors, unless the state has submitted, and EPA has approved, a precursor analysis demonstrating that emissions from a particular precursor do not contribute significantly to PM_{2.5} levels that exceed the standard in the area. Utah has not included any such precursor demonstration with the Serious Area SIP for the Salt Lake City, UT nonattainment area. The list of PM_{2.5} precursors includes SO₂, NO_x, VOC and ammonia.

5.2 BACM Process

The Process for determining BACM/BACT for Serious PM_{2.5} Areas is articulated in 40 CFR 51.1010, and elaborated upon in the preamble to the rule. Essentially, this is a five step process where:

Step one is the development of a comprehensive inventory for the area, which aids in identifying the various source categories that contribute emissions to the airshed.

⁵ See SIP Section IX.A.21, Chapter 6 for a discussion of RACM/RACT in the Salt Lake City, UT PM_{2.5} nonattainment area.

Step two is to identify potential control measures. The list of these potential measures should include options not previously considered as RACM/RACT for the area during the development of the Moderate Area SIP. In Step three, a determination is made for each of the potential control measures to see whether or not it would be technologically feasible to implement. Step four is a determination of economic feasibility applied to each of the potential control measures that was determined to be technologically feasible. EPA did not establish a specific fixed \$/ton cost threshold for economic feasibility determinations, but indicated that states would need to consider emission reduction measures with higher costs per ton when assessing the economic feasibility of BACM/BACT controls as compared to the criteria applied in the RACM/RACT analysis for the same nonattainment area. Step five is to determine the earliest date by which an economically feasible control measure can be implemented, in whole or in part.

5.3 Existing Control Measures

Ultimately, all control measures and technologies will have an effect on emission rates, and it is important to reflect these emission rates in the attainment demonstration. Some of these control measures will be new and will have resulted from the exercise of ensuring that BACM/BACT will be implemented following reclassification of the area to Serious, but other control measures will already exist. Since about 1970 there have been regulations at both state and federal levels to mitigate air contaminants. Utah's permitting rules require a review of new and modified major stationary sources in nonattainment areas, as is required by Section 173 of the Clean Air Act. Beyond that however, even minor sources and minor modifications to major sources planning to locate anywhere in the state are required to undergo a new source review analysis and receive an approval order to construct. Part of this review is an analysis to ensure the ongoing application of Best Available Control Technology (BACT). Along the central Wasatch Front, major and minor⁶ stationary sources have been required to reduce emissions at several junctures to address nonattainment issues with SO₂, ozone, PM₁₀ and PM_{2.5}. In reviewing the existing control measures to see if they meet BACM/BACT, states may not simply rely on prior BACT, LAER, and BART analyses for the purposes of showing that a source has also met BACT for the PM_{2.5} NAAQS. Rather, EPA expects that in step two of the determination process, the state would identify such measures as "existing measures" that should be further evaluated as potential BACM or BACT. Existing controls also affect the emission rates from non-stationary source categories. The federal motor vehicle control program has been one of the most significant control strategies affecting emissions that lead to PM_{2.5}. Tier 1 and 2 standards were implemented by 1997 and 2008 respectively. Similarly, the Heavy-Duty Engine and Vehicle Standards took effect in 2007 and were fully phased in by 2010. Air Quality benefits -- particularly those stemming from the Tier 2 and heavy-duty vehicle standards

⁶ Within the context of this SIP, minor stationary sources are treated as "area sources". Such sources are typically regulated through promulgation of area source rules affecting various source categories.

-- continue to be realized as older higher polluting vehicles are replaced by newer cleaner vehicles. This trend may be seen in the inventory projections for on-road mobile sources despite the growth in vehicles and vehicle miles traveled that are factored into the same projections. Tier 3 standards will continue the progress made since the late-1960s. Tier 3 became effective in 2017 and will be fully phased in by 2025 and will reduce emissions from a typical passenger vehicle by 70 to 80 percent.

To supplement the federal motor vehicle control program, Inspection / Maintenance (I/M) Programs were implemented in Salt Lake, Davis, and Weber Counties. These programs have been effective in identifying vehicles that no longer meet the emission specifications for their respective makes and models, and in ensuring that those vehicles are repaired in a timely manner.

Emissions from non-road mobile emission sources also benefit from several significant regulatory programs enacted at the federal level. This category of emitters includes airplanes, locomotives, hand-held engines, and larger portable engines such as generators and construction equipment. The effectiveness of these controls has been incorporated into the "NONROAD" model UDAQ uses to compile the inventory information for this source category. These measures affect not only the levels of current emissions, but some continue to affect emissions trends as well.

5.4 SIP Controls

Beyond the benefits attributable to the controls already in place, there are new controls identified by this SIP that provide additional benefit toward reaching attainment. A summary of the BACM/BACT review is presented here for each of the emission source sectors.

Stationary Point sources:

Best Available Control Technology – EPA has long interpreted BACM to include BACT, and in the same way that RACT is generally applied to stationary sources BACT is also regarded as a part of BACM that is typically applied to the review of stationary sources. This is not to say that BACT does not consider control measures other than technologies. The requirement for BACT at existing sources in the context of PM_{2.5} NAAQS implementation is separate and distinct from the BACT requirement for permitting new and modified sources under the Prevention of Significant Deterioration (PSD) program. However, BACT determinations for PM_{2.5} SIP purposes are to follow the same process and criteria that stem from the PSD program.

This SIP used the definition of "major stationary source" to compile a list of sources that would receive a source-specific BACT review. For a serious PM_{2.5} nonattainment area, this means any source that emits, or has the potential to emit, 70 ton per year or more of direct PM_{2.5} or any PM_{2.5} precursor. The 2014 tri-annual emissions inventory was used to assess the actual emissions. The rest of the stationary (point) sources were assumed to represent a portion of the overall "area source" inventory.

Sources meeting the criteria described above were individually evaluated to determine whether their operations would be consistent with BACT.

In conducting the analysis, UDAQ found that, as a whole, the large stationary sources were already operating with a high degree of emission control. It follows that the percentage of SIP related emissions reductions is not large relative to the overall quantity

1 of emissions. As stated before, many of these sources were recently reviewed to ensure
2 RACT as part of the Moderate Area SIP. Routine permitting in the Salt Lake City
3 nonattainment area already includes BACT as an ongoing standard of review, and when
4 developing the Moderate Area SIP, UDAQ generally identified a level of emission
5 control that would be more consistent with best available controls than the reasonably
6 available controls that were required.

7 For the Salt Lake City, UT nonattainment area, there are 26 stationary point sources that
8 met or meet the threshold of 70 tons or more per year for PM_{2.5} or any precursor. The
9 emissions from these sources that were modeled for 2016, 2017, 2019, and 2020 are
10 shown below in Table 4.2. Note that these emissions also include any growth projections
11 that were applied.

12 The BACT analysis for each of the listed sources may be found in the Technical Support
13 Document.

14 The actual emission limits and operating procedures that reflect the implementation of
15 BACM/BACT are listed in SIP Subsection IX. Part H. 11. & 12, which is made
16 enforceable via incorporation into the Utah Air Quality Rules at R307-110-17.

17 *New Source Review / Banked Emission Reduction Credits* – Under Utah’s new source
18 review rules in R307-403-8, banking of emission reduction credits (ERCs) is permitted to
19 the fullest extent allowed by applicable Federal Law as identified in 40 CFR 51,
20 Appendix S, among other documents. Under Appendix S, Section IV.C.5, a permitting
21 authority may allow banked ERCs to be used under the preconstruction review program
22 (R307-403) as long as the banked ERCs are identified and accounted for in the SIP
23 control strategy. For the Moderate Area PM_{2.5} SIP, however, it was not possible to
24 include banked ERCs in the attainment demonstration. The PM_{2.5} SIP adopted by the Air
25 Quality Board on December 4, 2013 did not include banked PM_{2.5} or PM_{2.5} precursor
26 ERCs in the attainment demonstration and therefore under R307-403-8 any ERCs that
27 were banked prior to December 4, 2013 could no longer be used as emission offsets for
28 PM_{2.5} nonattainment areas. The use of these existing banked ERCs to meet the
29 requirements of existing SIPs for PM₁₀, SO₂ and ozone are not affected by the PM_{2.5} SIP
30 and would be evaluated according to the provisions of those SIPs. In this Serious Area
31 SIP, the handful of ERCs generated after December 4, 2013 for PM_{2.5} or PM_{2.5} precursors
32 has been accounted for in the modeled attainment demonstration and are eligible to be
33 used as emission offsets for PM_{2.5} or PM_{2.5} precursors. A listing of these ERCs has been
34 included in the Technical Support Documentation.

35 36 Area sources:

37 Smaller stationary sources are too numerous to warrant individual attention, but they
38 must also implement BACM/BACT.

39 The area source BACM analysis consisted of a thorough review of the entire seasonally
40 adjusted area source inventory for anthropocentrically derived direct PM_{2.5} and precursor
41 constituents.

42 The analysis centered on whether best control measures are available for a given source
43 category. A search through the literature identified EPA guidance documents and
44 regulations including: Control Techniques Guidelines (CTG), Alternative Control
45 Techniques (ACT), and New Source Performance Standards (NSPS). Other sources of
46 information included the Ozone Transport Commission’s (OTC) model rules as well as
47 rules from other serious nonattainment air districts addressing ozone and/or PM_{2.5}.

For the BACM review, each of UDAQ's existing area source rules⁷ was re-evaluated with respect to these examples to ensure that all appropriate source categories have been addressed in rulemaking, and that the level of control required is consistent with BACM. For newly identified controls or enhancement of existing controls, an evaluation was made to determine technological and economic feasibility. The BACM review resulted in revisions to 13 different rules which affect surface coating (for a variety of different surfaces), graphic arts, and Aerospace Manufacture & Rework Facilities. At the same time however, a cleaning solvent VOC limit of 0.21 lb/gal found in some of these rules was found to be overly aggressive and had to be relaxed. The overall BACT analysis for the area source rules may be found in the Technical Support Document. The area source rules have been incorporated into the Utah Air Quality Rules at R307. **Table 5.1** shows the effectiveness of the area source rules within the Salt Lake City, UT nonattainment area by indicating the quantities of emissions eliminated from the inventory for each of the relevant years. Emission units are in lb/day.

Area Source Rule Name	Emissions Reduced in Pounds Per Day (lb/day)									
	2016 Base Year					2017 Milestone Year				
	NOx	VOC	NH3	SO2	PM2.5	NOx	VOC	NH3	SO2	PM2.5
adhesive/sealants	0.00	869.91	0.00	0.00	0.00	0.00	1,176.59	0.00	0.00	0.00
aerospace										
aggregate operations	0.00	0.00	0.00	0.00	5.59	0.00	0.00	0.00	0.00	5.58
appliance										
autobody	0.00	344.17	0.00	0.00	0.00	0.00	698.06	0.00	0.00	0.00
coil/containers										
commercial cooking	0.00	51.31	0.00	0.00	0.00	0.00	52.01	0.00	0.00	0.00
consumer products	0.00	4,372.48	0.00	0.00	0.00	0.00	4,435.39	0.00	0.00	0.00
degreasing										
fabric/vinyl										
flat wood										
fugitive dust	0.00	0.00	0.00	0.00	1,442.43	0.00	0.00	0.00	0.00	1,455.69
graphic art										
Hydronic heater ban	5.80	188.20	4.80	5.80	178.60	5.60	187.40	4.60	5.60	178.40
Landfill	0.00	276.51	0.00	0.00	0.00	0.00	281.87	0.00	0.00	0.00
magnet wire										
metal furniture										
misc metal										
paint	0.00	6,089.71	0.00	0.00	0.00	0.00	6,177.26	0.00	0.00	0.00
paper/film/foil										
pilot light	3,383.76	197.98	0.00	21.60	15.48	4,511.65	263.95	0.00	28.79	20.62
plastic										
Residential wood burning ban	1,344.82	10,436.32	389.15	133.89	9,046.46	1,339.19	10,405.97	386.33	133.26	9,019.87
water heaters										
wood furniture manuf										
Total Area Source Emissions Reduced	4,734.4	22,826.6	393.9	161.3	10,688.6	5,856.4	23,678.5	390.9	167.7	10,680.2

⁷ As part of the Moderate Area PM_{2.5} SIP, UDAQ introduced or augmented 25 area source rules to control emissions of PM_{2.5} or PM_{2.5} precursors.

SLC, UT PM2.5 Nonattainment Area		Emissions Reduced in Pounds Per Day (lb/day)								
Area Source Rule Name	2019 Attainment Year					2020 Milestone Year				
	NOx	VOC	NH3	SO2	PM2.5	NOx	VOC	NH3	SO2	PM2.5
adhesive/sealants	0.00	1,513.14	0.00	0.00	0.00	0.00	1,533.71	0.00	0.00	0.00
aerospace	0.00	28.73	0.00	0.00	0.00	0.00	43.13	0.00	0.00	0.00
aggregate operations	0.00	0.00	0.00	0.00	5.57	0.00	0.00	0.00	0.00	5.56
appliance	0.00	0.46	0.00	0.00	0.00	0.00	0.69	0.00	0.00	0.00
autobody	0.00	1,435.97	0.00	0.00	0.00	0.00	1,817.76	0.00	0.00	0.00
coil/containers	0.00	83.64	0.00	0.00	0.00	0.00	125.00	0.00	0.00	0.00
commercial cooking	0.00	53.57	0.00	0.00	0.00	0.00	54.29	0.00	0.00	0.00
consumer products	0.00	4,559.88	0.00	0.00	0.00	0.00	4,625.34	0.00	0.00	0.00
degreasing	0.00	1,014.89	0.00	0.00	0.00	0.00	1,527.89	0.00	0.00	0.00
fabric/vinyl	0.00	362.02	0.00	0.00	0.00	0.00	442.96	0.00	0.00	0.00
flat wood	0.00	11.37	0.00	0.00	0.00	0.00	17.15	0.00	0.00	0.00
fugitive dust	0.00	0.00	0.00	0.00	1,483.96	0.00	0.00	0.00	0.00	1,497.15
graphic art	0.00	995.47	0.00	0.00	0.00	0.00	1,062.39	0.00	0.00	0.00
Hydronic heater ban	5.80	186.60	4.80	5.80	177.00	5.80	186.00	4.80	5.80	176.60
Landfill	0.00	293.81	0.00	0.00	0.00	0.00	299.37	0.00	0.00	0.00
magnet wire	0.00	22.03	0.00	0.00	0.00	0.00	22.18	0.00	0.00	0.00
metal furniture	0.00	167.13	0.00	0.00	0.00	0.00	249.51	0.00	0.00	0.00
misc metal	0.00	273.76	0.00	0.00	0.00	0.00	411.43	0.00	0.00	0.00
paint	0.00	6,344.07	0.00	0.00	0.00	0.00	6,441.84	0.00	0.00	0.00
paper/film/foil	0.00	97.89	0.00	0.00	0.00	0.00	147.62	0.00	0.00	0.00
pilot light	5,834.66	396.40	0.00	43.19	31.00	4,926.20	361.78	0.00	39.47	28.29
plastic	0.00	189.32	0.00	0.00	0.00	0.00	222.41	0.00	0.00	0.00
Residential wood burning ban	1,332.30	10,343.10	385.71	132.01	8,964.81	1,327.61	10,311.50	384.46	131.70	8,939.47
water heaters	1,396.75	0.00	0.00	0.00	0.00	1,632.52	0.00	0.00	0.00	0.00
wood furniture manuf	0.00	604.15	0.00	0.00	0.00	0.00	910.88	0.00	0.00	0.00
Total Emissions Reduced: (lb/day)	8,569.5	28,977.4	390.5	181.0	10,662.3	7,892.1	30,814.8	389.3	177.0	10,647.1

Table 5.1, Emissions Reductions from Area Source SIP Controls

On-road mobile sources:

Federal Regulations

Section 209(a) of the Clean Air Act (CAA) preempts states other than California from adopting or enforcing standards for on-highway vehicles. Nevertheless, emissions reduction credit for federal on-highway vehicle controls was accounted for because federal control effectiveness has been incorporated into the MOVES model which the Utah Division of Air Quality (UDAQ) uses to calculate on-road emissions. Additional information is provided in the Technical Support Document.

State Regulations

Inspection/Maintenance (I/M) programs are already in place for Salt Lake, Davis and Weber Counties. Utah Code Annotated 41-6a-1642 gives authority to each county to implement and manage an I/M program to attain and maintain any National Ambient Air Quality Standard (NAAQS). I/M programs were implemented in Salt Lake and Davis counties in 1984, and a program for Weber County was added in 1990. These programs have been effective in both identifying vehicles that no longer meet the emission specifications for their respective makes and models and ensuring that those vehicles are repaired in a timely manner.

Davis, Salt Lake and Weber Counties current I/M programs consist of decentralized, test-and-repair network for the testing of all model year 1968 and newer vehicles except for exempt vehicles registered in the applicable county. Vehicles less than two years old as of January 1 on any given year are exempt from an emissions inspection. Vehicles from two to five years old as of January 1 on any given year are inspected biennially. Vehicles six years old and older as of January 1 on any given year are inspected annually. Vehicles

1 1996 and newer are subject to an OBD II inspection. Vehicles 1995 and older are subject
2 to a two-speed idle test. To ensure that analyzers are the highest quality and to take
3 advantage of improved technology, Davis, Salt Lake and Weber Counties recently
4 updated the test analyzers used in their respective I/M programs.

5 Off-road mobile sources:

6 Section 209(e) of the Clean Air Act (CAA) preempts states other than California from
7 adopting or enforcing emissions standards for terrestrial and marine non-road engines or
8 vehicles. Similarly, CAA section 233 preempts states from adopting or enforcing
9 emissions standards from aircraft or aircraft engines. For this reason, the Utah Division
10 of Air Quality (UDAQ) did not consider any SIP controls for non-road mobile sources
11 beyond those already promulgated at the federal level. Nevertheless, emissions reduction
12 credit for these federal controls was accounted for because their effectiveness has been
13 incorporated into the NONROAD model which UDAQ uses to calculate non-road
14 emissions. Additional information is provided in the Technical Support Document.

Chapter 6 – ATTAINMENT DEMONSTRATION

6.1 Air Quality Modeling

UDAQ used the Comprehensive Air Quality Model with Extensions (CAMx) version 6.30 for air quality modeling. CAMx v6.30 is a state-of-the-art air quality model that includes State of Utah funded enhancements for wintertime modeling. These enhancements include snow chemistry, topographical and surface albedo refinements. CAMx is an EPA approved model for use in SIP modeling. Its configuration for use in this SIP, with respect to model options and model adjustments, is discussed in the Technical Support Document.

Emissions Preparation

The emissions processing model used in conjunction with CAMx is the Sparse Matrix Operator Kernel Emissions Modeling System (SMOKE) version 3.6.5⁸. SMOKE prepares the annual emissions inventory for use in the air quality model. There are three aspects to the preparation of an annual emissions inventory for air quality modeling:

- Temporal: Convert emissions from annual to daily, weekly and hourly values.
- Spatial: Convert emissions from a county-wide average to gridded emissions.
- Speciation: Decompose PM_{2.5} and VOC emissions estimates into individual subspecies using the latest Carbon Bond 6 speciation profiles.

The process of breaking down emissions for the air quality model was done with sets of activity profiles and associated cross reference files. These are created for point or large industrial source emissions, smaller area sources, and mobile sources. Direct PM_{2.5} and PM_{2.5} precursor estimates were modified via temporal profiles to reflect wintertime conditions.

Activity profiles and their associated cross reference files from the EPA's 2011v6⁹ modeling platform were used. For stationary non-point and mobile sources, spatial surrogates from the EPA Clearinghouse for Inventories and Emissions Factors (CHIEF¹⁰) were used to distribute emissions in space across the modeling domain. Emissions from large industrial sources (i.e., point) were placed at the location of the source itself. Where reliable local information was available (e.g., population density, traffic demand modeling, residential heating), profiles and surrogates were modified or developed to reflect that information.

Photochemical Modeling Domains and Grid Resolution

The UDAQ CAMx 6.30 modeling framework consists of two spatial domains: a high-resolution 1.33 km domain nested inside of a coarser 4 km domain (see Figure 6.1,

⁸ <https://www.emascenter.org/smoke/>

⁹ <https://www.epa.gov/air-emissions-modeling/2011-version-6-air-emissions-modeling-platforms>

¹⁰ <https://www.epa.gov/chief>

below). This configuration allows one to efficiently integrate regional effects with local impacts within the Salt Lake City nonattainment area. Vertical resolution in the model consists of 41 layers extending to the top of the atmosphere.

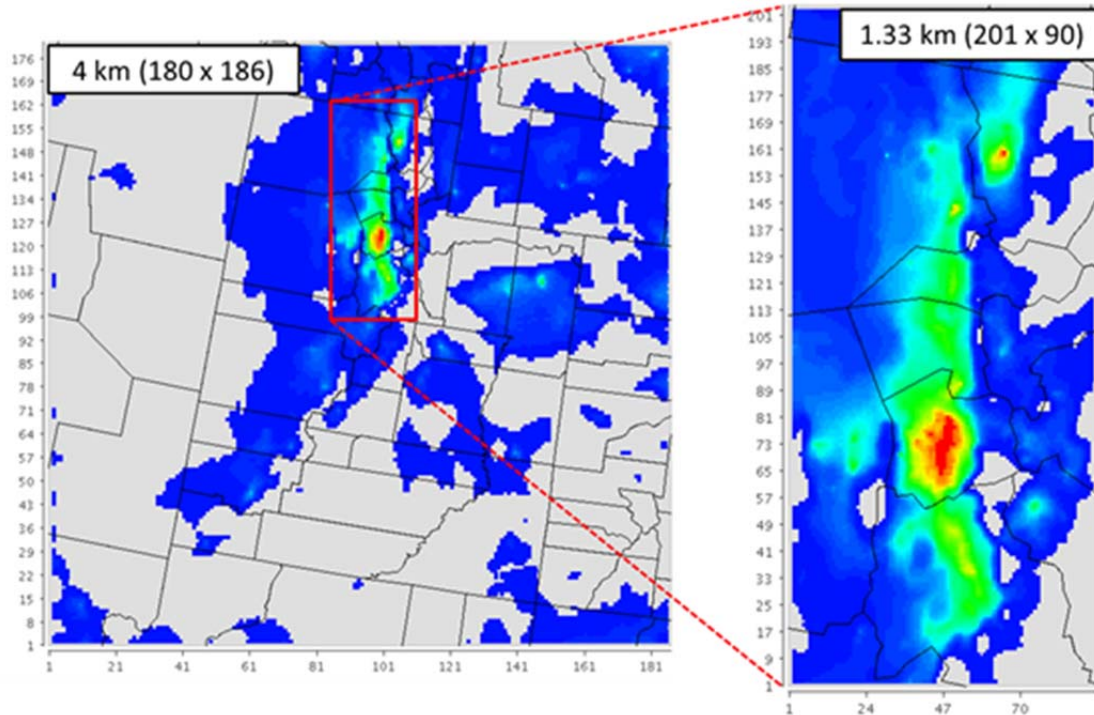


Figure 6.1: Two CAMx modeling domains in two-way nesting configuration.

The UDAQ 4 km coarse domain covers the entire state of Utah, a significant portion of Eastern Nevada (including Las Vegas), as well as smaller portions of Idaho, Wyoming, Colorado, and Arizona. The fine 1.33 km domain covers all of Utah's three PM_{2.5} nonattainment areas, including the Salt Lake City nonattainment area. Throughout this document, we will refer to the fine 1.33 km domain as the “modeling domain” when the coarse domain is not specified.

Meteorological Data

Meteorological modeling was carried out by the University of Utah with financial support from UDAQ.

Meteorological inputs were derived using the Weather Research and Forecasting¹¹ (WRF) Advanced Research WRF (WRF-ARW) Model to prepare meteorological datasets for our use with the photochemical model. WRF contains separate modules to compute different physical processes such as surface energy budgets and soil interactions, turbulence, cloud microphysics, and atmospheric radiation. Within WRF, the user has many options for selecting the different schemes for each type of physical process. There is also a WRF Preprocessing System (WPS) that generates the initial and boundary conditions used by WRF, based on topographic datasets, land use information, and larger-scale atmospheric and oceanic models.

¹¹ <https://www.mmm.ucar.edu/weather-research-and-forecasting-model>

1 Model performance of WRF was assessed against observations at sites maintained by the
2 University. A summary of the performance evaluation results for WRF is included in the
3 Technical Support Document:

4 WRF has reasonable ability to replicate the vertical temperature structure of the boundary
5 layer (i.e., the temperature inversion), although it is difficult for WRF to reproduce the
6 inversion when the inversion is shallow and strong (i.e., an 8 degree temperature increase
7 over 100 vertical meters).

8 **Episode Selection**

9 Part of the modeling exercise involves a test to see whether the model can successfully
10 replicate the PM_{2.5} mass and composition that was observed during some prior episode(s)
11 of elevated PM_{2.5} concentration.

12 The selection of an appropriate episode, or episodes, for use in this exercise requires
13 some forethought and should determine the meteorological episode that helps produce the
14 best air quality modeling performance.

15 EPA's April 2007 "Guidance on the Use of Models and Other Analyses for
16 Demonstrating Attainment of Air Quality Goals for Ozone, PM_{2.5}, and Regional Haze"
17 identifies some selection criteria that should be considered for SIP modeling, including:

- 18 • Select episodes that represent a variety of meteorological conditions that lead to
19 elevated PM_{2.5}.
- 20 • Select episodes during which observed concentrations are close to the baseline
21 design value.
- 22 • Select episodes that have extensive air quality data bases.
- 23 • Select enough episodes such that the model attainment test is based on multiple
24 days at each monitor violating NAAQS.

25 After careful consideration, the following meteorological episodes were selected as
26 candidates for Utah's SIP modeling:

- 27 • January 1-10, 2011
- 28 • December 7-19, 2013
- 29 • February 1-16, 2016

30 In addition to the criteria identified in the modeling guidance, each of these candidate
31 episodes may be characterized as having the following atmospheric conditions:

- 32 • Nearly non-existent surface winds
- 33 • Light to moderate winds aloft (wind speeds at mountaintop < 10-15 m/s)
- 34 • Simple cloud structure in the lower troposphere (e.g., consisting of only one or no
35 cloud layer)

- Singular 24-hour PM_{2.5} peaks suggesting the absence of weak intermittent storms during the episode

Previous work conducted by the University of Utah and Utah Division of Air Quality (DAQ) showed the four conditions listed above improve the likelihood for successfully simulating wintertime persistent cold air pools in the Weather Research and Forecasting (WRF) model¹².

A comprehensive discussion of the meteorology model performance for all three episodes may be found in the Technical Support Document, as well as at the link below.

<https://documents.deq.utah.gov/air-quality/planning/technical-analysis/research/model-improvements/3-wintertime-episodes/DAQ-2017-014342.pdf>

Model adjustments

In order to better simulate Utah's winter-time inversion episodes six different adjustments were made to CAMx input data:

1. Increased vertical diffusion rates (Kvpatch)
2. Lowered residential wood smoke emissions to reflect burn ban compliance during forecasted high PM_{2.5} days (burn ban)
3. Ozone deposition velocity set to zero and increased urban area surface albedo (snow chemistry)
4. Cloud water content reduced during certain days (cloud adjustment)
5. Ammonia injection to account for missing ammonia sources in UDAQ's inventory. This is defined as artificially adding non-inventoried ammonia emissions to the inventoried emissions that are input into CAMx.
6. Reduced the dry deposition rate of ammonia by setting ammonia Rscale to 1. Rscale is a parameter in CAMx that reflects surface resistance.

Depending on the episode, different adjustments were applied. All adjustments were applied to the January 2011 episode while select adjustments were applied to the other two episodes.

Kvpatch improved overall model performance by enhancing vertical mixing over urban areas. Snow chemistry modifications, which included reducing ozone deposition velocity and increasing surface albedo over urban areas, helped improve the model performance by better representing secondary ammonium nitrate formation during winter-time inversion episodes in Utah.

Ammonia injection values were based on measurements conducted during February 2016. These measurements were used to determine the ammonia injection values for the February 2016 episode. Similar injection values were then assumed for the January 2011 episode.

¹² <https://www.mmm.ucar.edu/weather-research-and-forecasting-model>

Cloud adjustments were only applied to the January 2011 episode, which was characterized by cloud cover on January 6-8 over the Salt Lake Valley. This cloud cover led to a high bias in sulfate due to the effect of ammonia on the gas-to-particle partitioning of sulfate in clouds. Application of the cloud adjustment scheme helped reduce this bias.

Rscale modification and burn ban adjustments were also only applied to the January 2011 episode. The burn ban adjustments reflect the compliance rate with the state's two-stage policy ban on wood-burning.

Episodic model performance

Shown below for each of three episodes are the CAMx performance results in total 24-hour PM_{2.5} concentrations.

January 1-10, 2011

For the January meteorological episode, CAMx performance in 24-hour PM_{2.5} is generally good at Hawthorne (Salt Lake County) (**Figure 6.2.1**). However, the earlier part of the modeled episode at Hawthorne is impacted by the absence of thin mid-level clouds that were present during January 3-5. The absence of clouds here had the effect of warming the surface and increasing the mixing height in the simulation. Kvpitch depth was lowered during this period to account for this, while keeping modeled primary aerosol concentrations reasonable.

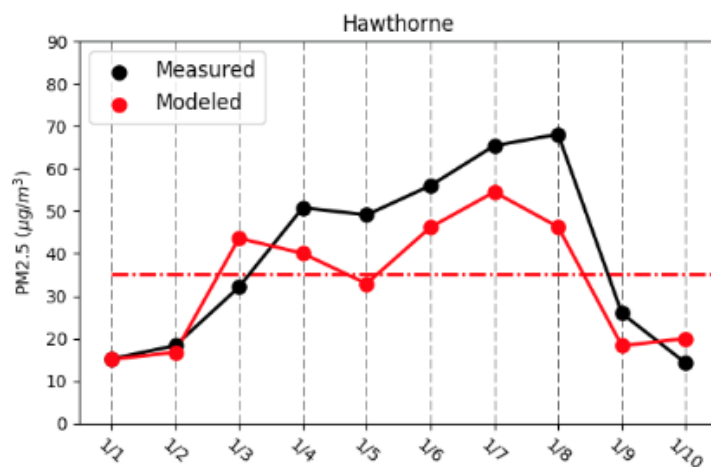


Figure 6.2.1: 24-hr PM_{2.5} concentrations during January, 2011 episode. Observed (black) vs. modeled (red) for Hawthorne, Salt Lake County

Looking at **Figure 6.2.2**, observed speciated PM_{2.5} mass from the Hawthorne Chemical Speciation Network (CSN) monitor (January 7), there is good agreement in nitrate (NO₃) and ammonium (NH₄) with the CAMx modeling results. The agreement between modeled and observed NO₃ is a benefit from the ammonia injection. Simulated fine crustal matter (CM) and elemental carbon (EC) concentrations were a bit higher than observed. The overestimation ~~[in these two primary aerosols were the likely result of a high bias in MOVES 2014a (EC) and the re-suspended road dust calculation tool provided by the EPA (CM)]~~ of CM was likely the result of a high bias in the re-suspended road dust calculation tool (AP-42).

Measured vs. Modeled

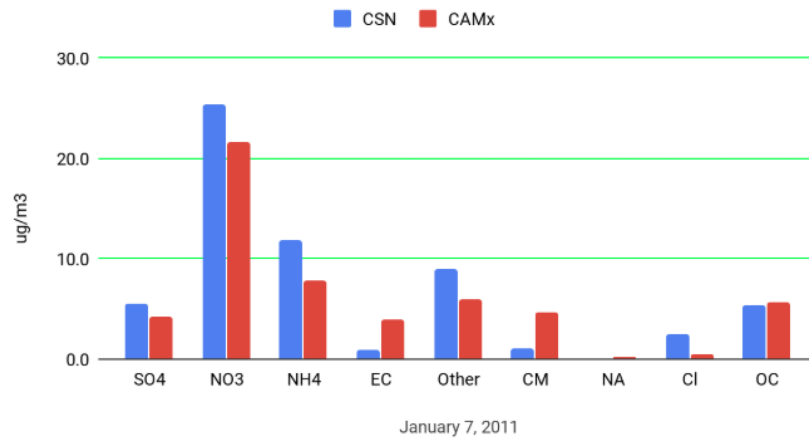


Figure 6.2.2: 24-hr speciated PM_{2.5} mass (ug/m³) for January 7, 2011. Blue (red) bars represent measured (modeled) mass for Hawthorne, Salt Lake County.

December 7-19, 2013

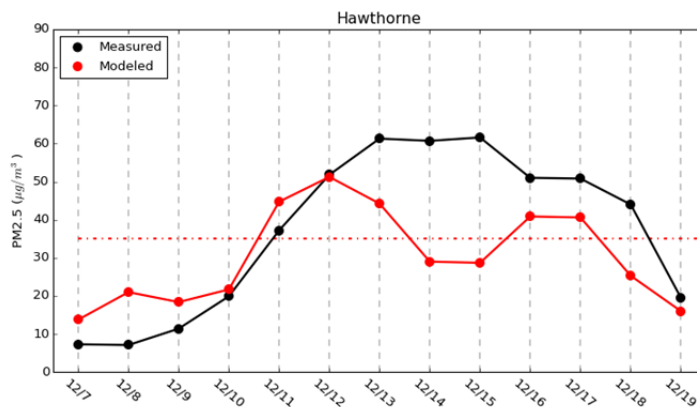


Figure 6.3.1: 24-hr PM_{2.5} concentrations during December, 2013 episode. Observed (black) vs. modeled (red) for Hawthorne, Salt Lake County.

Figure 6.3.1 indicates that, at Hawthorne, modeled PM_{2.5} was of a similar magnitude as observed. However, there was a bimodality in the modeled results not observed in measurements. While observations show peak PM_{2.5} concentrations during December 13-15, CAMx is producing a local minima.

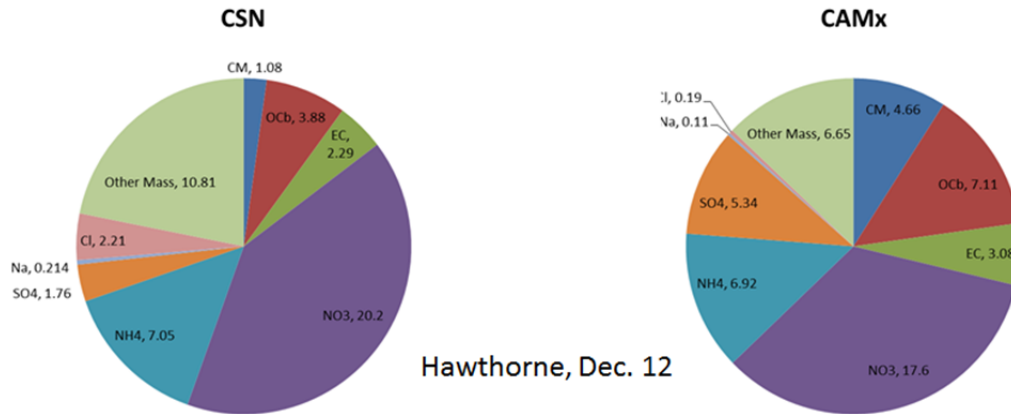


Figure 6.3.2: 24-hr speciated PM_{2.5} mass (ug/m³), December 12, 2013. Observed (left) vs. modeled (right). Hawthorne, Salt Lake County.

Speciated AQS data was available for only one day (December 12) at the onset of the multi-day peak PM_{2.5} period (December 12-16). NH₄ and NO₃ appear well simulated. As with the January, 2011 episode, the modeled crustal matter apportionment is much higher than the observed. Modeled SO₄ was roughly 3 times higher than observed (see **Figure 6.3.2**).

Overall, the speciation for December 12 appears reasonable, but the use of the December, 2013 episode data may not be a good choice for attainment demonstration modeling. The anti-correlation between modeled and observed results during the peak PM_{2.5} shows that the December, 2013 CAMx performance is undesirable for SIP development.

February 1-16, 2016

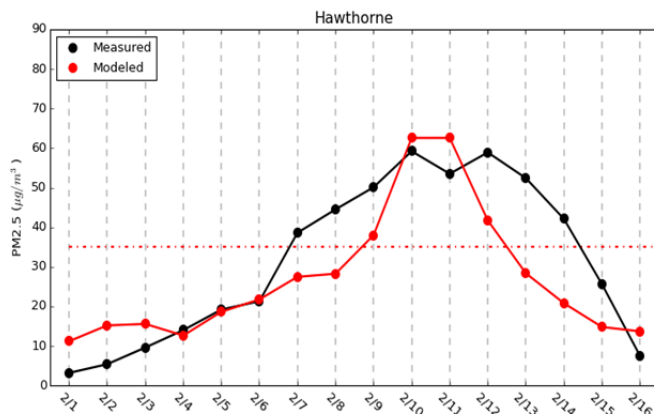


Figure 6.4.1: 24-hr PM_{2.5} concentrations during February, 2016 episode. Observed (black) vs. modeled (red) for Hawthorne, Salt Lake County.

Figure 6.4.1 shows that CAMx was able to simulate the peak PM_{2.5} concentration levels seen in monitored observations at Hawthorne for February, 2016. At Hawthorne, modeled PM_{2.5} tapered off rapidly during the latter part of the February episode (February 12-16).

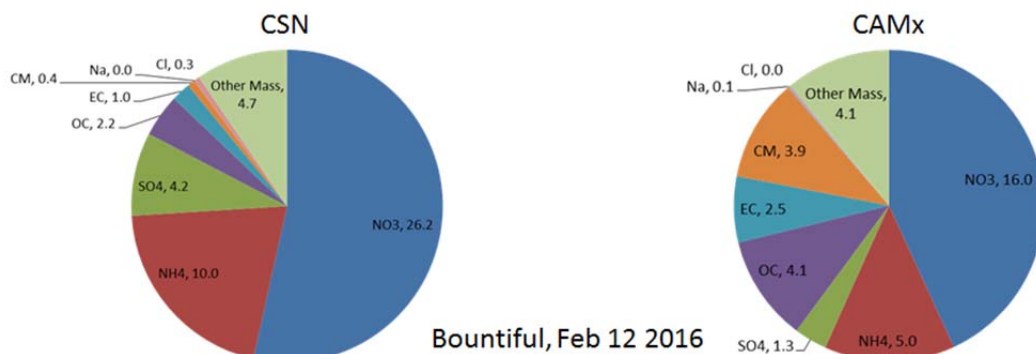


Figure 6.4.2: 24-hr speciated PM_{2.5} mass (ug/m³), February 12, 2016. Observed (top) vs. modeled (bottom). Bountiful, Davis County. Bountiful is used since Hawthorne measurements were unavailable.

It can be seen from **Figure 6.4.2** that the February 12, NO₃ and NH₄ simulations were relatively poor compared to the other two episodes considered. Modeled organic carbon (OC) was twice as high measured and SO₄ was under-represented. The CAMx results don't quite reflect the high wintertime PM_{2.5} composition one would expect during this period.

Conclusion

Examining the PM_{2.5} model performance for all three episodes, it's clear that CAMx performed best when using the January, 2011 WRF output. The WRF model was specifically calibrated to the meteorological conditions experienced during January, 2011; a period that coincided with the Persistent Cold Air Pool Study¹³ (PCAPS), an exhaustive field campaign focused exclusively on the Salt Lake Valley. The scatter plots below (**Figure 6.5**) show simulated PM_{2.5} (CAMx) against the PM_{2.5}, measured at Utah's Hawthorne federal reference method (FRM) monitor. Linear regression fits are also shown (dashed lines). The relatively tight dispersion in (FRM, CAMx) points along the diagonal black line (x=y) for January, 2011 implies that model bias is low and temporal correlation is high relative to when using WRF output for the other two episodes.

¹³ <http://www.pcaps.utah.edu/>

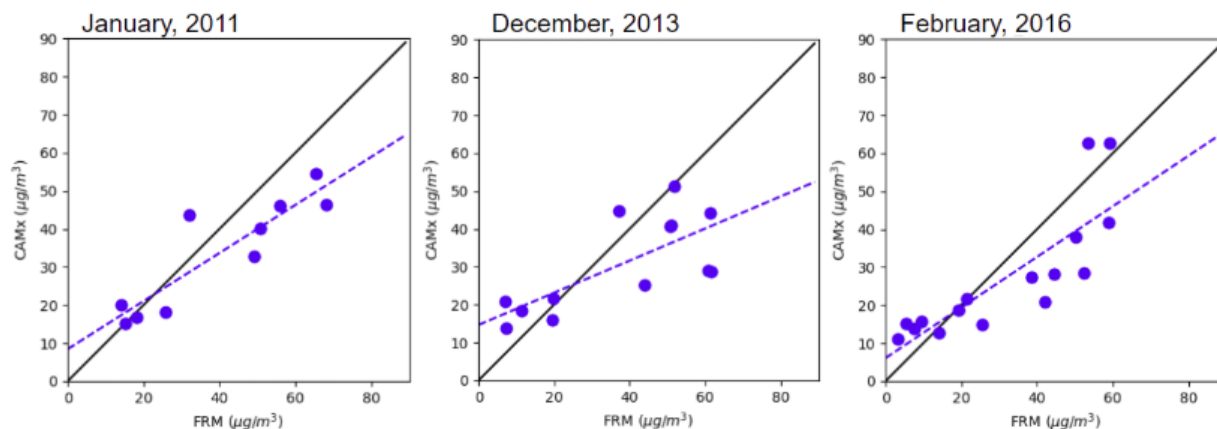


Figure 6.5: Modeled (vertical axis) versus measured (horizontal axis) 24-hour PM_{2.5} for three meteorological episodes. Dots represent each individual day of the modeling episode. Linear regression fits are shown for each episode (dashed line).

The January, 2011 WRF data produced superior performance for all important metrics when compared with the other two episodes. Therefore, UDAQ selected the January, 2011 episode to conduct its modeled attainment demonstration work. A more thorough discussion is provided in the Technical Support Document.

Photochemical Model Performance Evaluation

Introduction

To assess how accurately the photochemical model predicts observed concentrations and to demonstrate that the model can reliably predict the change in pollution levels in response to changes in emissions, a model performance evaluation was conducted. This model performance evaluation also provides support for the model modifications that were implemented (ammonia injection, albedo, snow cover, ozone deposition velocity, cloud-water content and vertical diffusion modifications) to more accurately reproduce winter-time inversion episodes. A detailed explanation of these model modifications as well as a more thorough examination of the model performance is provided in the Technical Support Document.

Available ambient monitoring data was used for this photochemical model performance evaluation. Data included 24-hr total PM_{2.5} and 24-hr chemically-speciated PM_{2.5} measurements collected at UDAQ's Hawthorne monitoring station in the Salt Lake City non-attainment area. Ammonia measurements collected during special field studies carried out in winters of 2016 were also used for this performance evaluation. These ammonia measurements were used since measurements of ammonia were not available during 2011. The evaluation was based on the December 31 – January 10, 2011 episode, which will be used for the modeled attainment test. The 2011 emissions inventory was considered for this purpose. The evaluation was also focused on days with PM_{2.5} concentration exceeding the 24-hr national ambient air quality standard ($> 35 \mu\text{g}/\text{m}^3$). December 31, which is a spin-up day, was excluded from this evaluation. A more detailed model performance evaluation that examines the model performance for ozone (O₃), nitrogen oxides (NO_x=NO+NO₂), carbon monoxide (CO) and volatile organic compounds (VOCs) is provided in the Technical Support Document. More details on the

model performance at various sites within the Salt Lake City non-attainment area are also included.

Daily PM_{2.5} Concentrations

Figure 6.6 shows 24-hr modeled and observed PM_{2.5} during January 1-10, 2011 at the Hawthorne monitoring station in the Salt Lake non-attainment area. Overall, the model accurately captures the temporal variation in PM_{2.5}. The gradual increase in PM_{2.5} concentration and its transition back to low levels are generally well reproduced by the model.

It is noteworthy that the overestimation in PM_{2.5} on January 3 at Hawthorne is related to the meteorological model performance on this day. While thin mid-level clouds were observed on January 3-4, these clouds were not simulated in the meteorological model, leading to an increasingly stable low-level boundary layer, particularly at night (details provided in Utah's meteorological model performance final report¹⁴). This limited the mixing of pollutants on January 3 in the model, resulting in an over-prediction in PM_{2.5} levels. The underestimation in PM_{2.5} on January 5, 2011 is also related to the meteorological model performance on this day, where the meteorological model overestimated the wind shear near the mixing height, leading to increased vertical instability in the simulated temperature structure and therefore lower modeled PM_{2.5} concentrations.

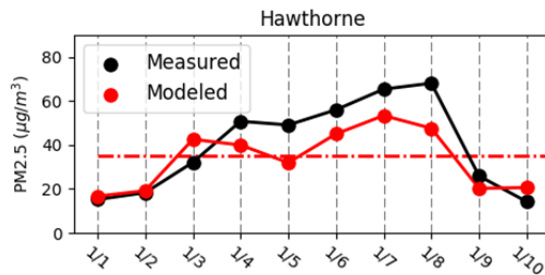


Figure 6.6: Ten-day time series of observed (black) and modeled (red) mean 24-hour PM_{2.5} concentrations (red) for January 1 - 10, 2011 (MDT) at Hawthorne, Salt Lake County. Dashed red line shows 24-hr PM_{2.5} NAAQS.

PM_{2.5} Chemical Speciation

To further investigate the model performance, UDAQ compared measured and modeled PM_{2.5} chemical species at the Hawthorne monitoring site, which is part of EPA's Chemical Speciation Network (CSN). **Figure 6.7** shows a comparison of the bulk chemical composition of measured and modeled PM_{2.5} at Hawthorne on January 7, 2011, which is the only PM_{2.5} exceedance day where measurement data is available. Chemical species, including nitrate (NO₃), sulfate (SO₄), ammonium (NH₄), organic carbon (OC), elemental carbon (EC), chloride (Cl), sodium (Na), crustal material (CM) and other species (other), were considered in this analysis.

The model performance for particulate nitrate (NO₃), which is the major PM_{2.5} component, was good, with both modeled and measured particulate nitrate accounting for

¹⁴<https://documents.deq.utah.gov/air-quality/planning/technical-analysis/research/model-improvements/3-wintertime-episodes/DAQ-2017-014342.pdf>

1 similar contributions to PM_{2.5} filter mass (40 and 41% respectively) (**panels b and d**).
2 Modeled and observed nitrate concentrations were also comparable, with modeled
3 concentration being biased low by about 15%. The model performance for particulate
4 sulfate was also reasonably good, with measured and modeled concentrations accounting
5 for 5.6 µg/m³ and 4.2 µg/m³ of total PM_{2.5} mass, respectively (**panels a and c**), resulting
6 in a low model bias of about 25%. Similarly to its performance for sulfate and nitrate, the
7 model was also biased low for ammonium by about 33.5%. This low model bias in
8 particulate ammonium can be attributed to the underestimation of ammonium chloride
9 (NH₄Cl) in the model.
10 Conversely, the model performance for organic carbon was quite good for January 7,
11 with modeled and observed concentrations being quite comparable. The model, on the
12 other hand, overestimated EC [~~which can be related to an overestimation of EC in Utah's~~
13 ~~mobile emissions modeling using MOVES 2014a.~~and CM. Crustal material was
14 ~~[also]~~likely overestimated~~[, likely]~~ due to an overestimation of re-suspended road dust in
15 the emissions inventory.
16
17

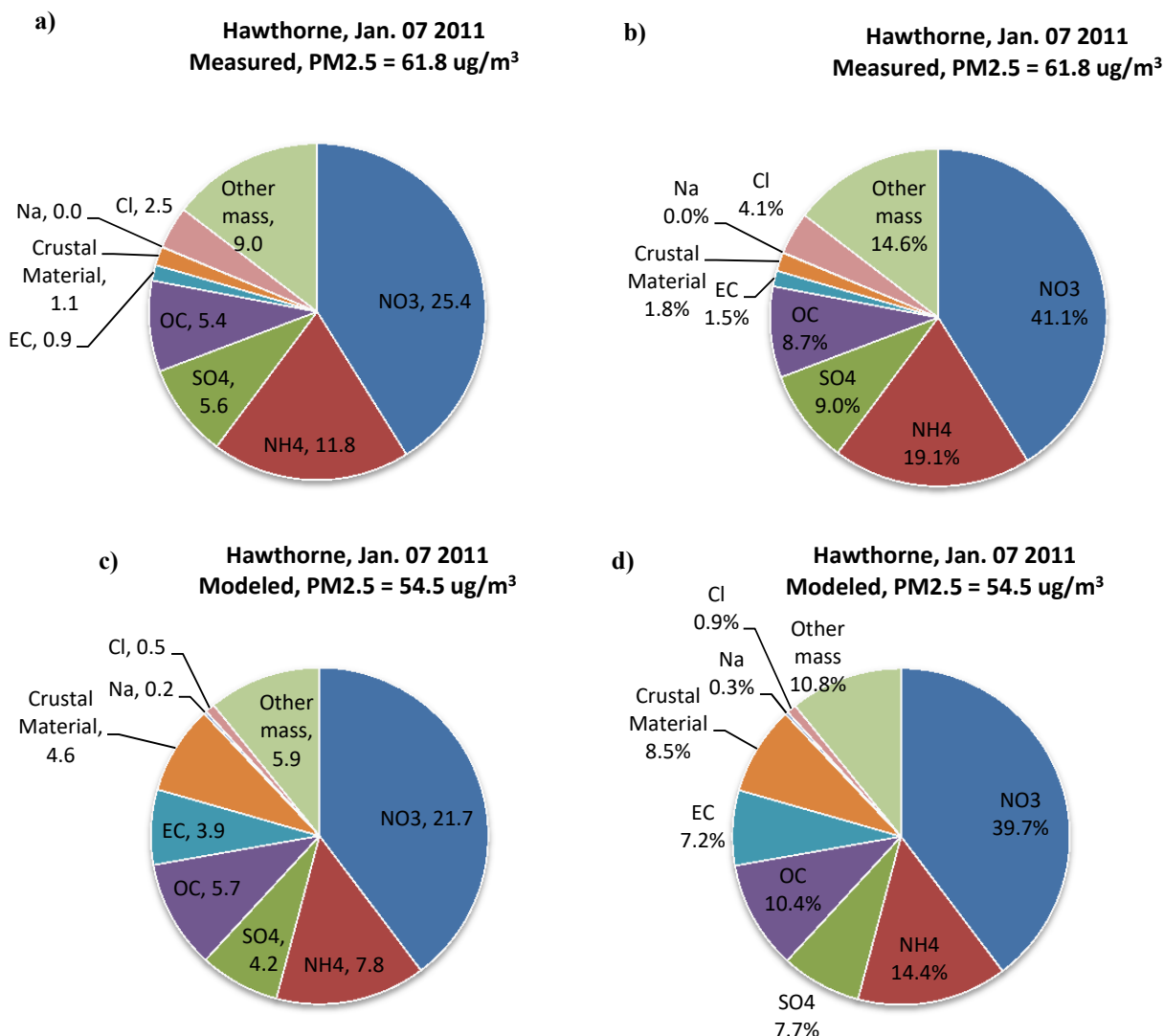


Figure 6.7, a-d: Measured (a,b) and modeled (c,d) mean 24-hour PM_{2.5} species for January 7, 2011 (MDT) at Hawthorne, Salt Lake County. Panels a and c show absolute concentrations (ug/m³) of PM_{2.5} chemical species while panels b and d display their percent contributions to total PM_{2.5}.

The model performance was also evaluated for ammonia (NH₃), which is an important precursor to the formation of ammonium nitrate, ammonium sulfate and ammonium chloride, all of which are important PM_{2.5} species accounting for over 50% of the PM_{2.5} mass during inversion events.

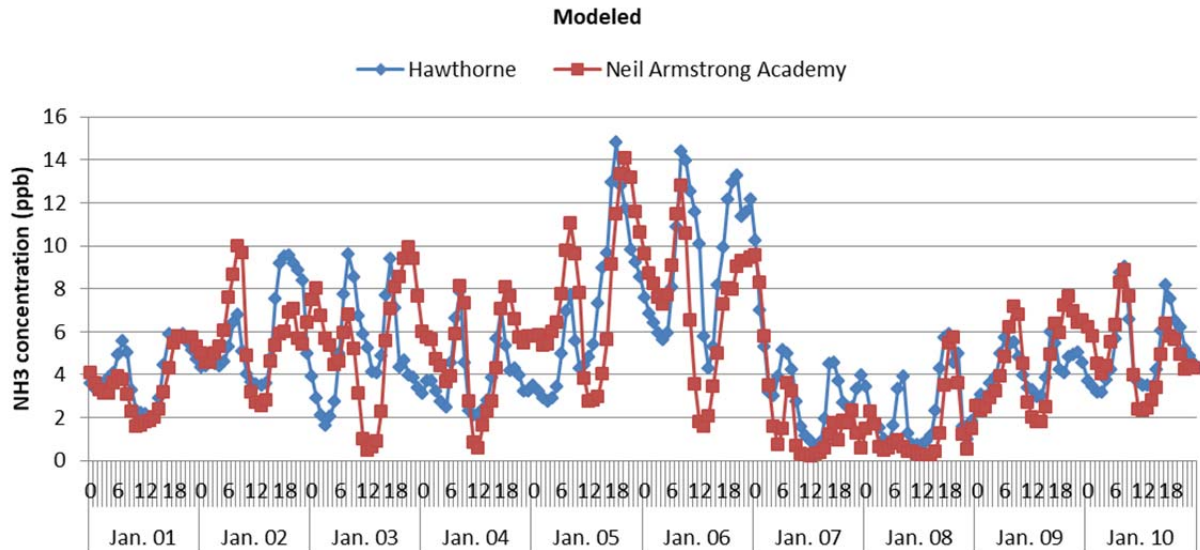


Figure 6.8: Hourly time series of modeled ammonia (ppm) for January 1 - 10, 2011 at Hawthorne, and Neil Armstrong Academy, Salt Lake County.

Modeled ammonia (**figure 6.8**) was compared to hourly ammonia measurements (**figure 6.9**) conducted at Neil Armstrong Academy during a special field study in winter 2016. Measurements from 2016 were considered since measurements of ammonia were not available during 2011. Hourly measurements were also only available at Neil Armstrong Academy, located in West Valley City in the Salt Lake non-attainment area. However, while these 2016 field study measurements cannot be directly compared to day-specific 2011 model simulations, the measurements are qualitatively useful to assess if the model predicts similar levels of ammonia during strong inversion conditions. A comparison of measured and modeled ammonia shows that modeled ammonia at Hawthorne and Neil Armstrong Academy is well within the range observed in 2016. It also displays a similar behavior to measured NH_3 , with NH_3 concentration dropping during peak $\text{PM}_{2.5}$ events during which the airshed is saturated and virtually all near-surface ambient ammonia has yielded to particulate ammonium.

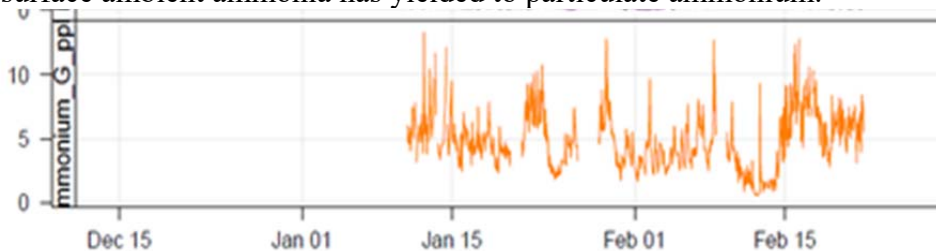


Figure 6.9: Hourly ammonia measurements from Neal Armstrong Academy (West Valley City, Salt Lake County). Note that ammonia drops during the persistent cold air pool period during Feb. 7 - 14, 2016.

Summary of Model Performance

The model performance replicating the buildup and clear out of $\text{PM}_{2.5}$ is good overall. The model captures well the temporal variation in $\text{PM}_{2.5}$. The gradual increase in $\text{PM}_{2.5}$

concentration and its transition back to low levels are generally well reproduced by the model. The model also predicts reasonably well PM_{2.5} concentration on peak days. It also overall replicates well the composition of PM_{2.5} on exceedance days, with good model performance for secondary nitrate and ammonium which account for over 50% of PM_{2.5} mass. Simulated ammonia concentrations are also within the range of those observed, further indicating that the model overall performs well. Several observations should be noted on the implications of these model performance findings on the attainment modeling presented in the following section. First, it has been demonstrated that model performance overall is good and, thus, the model can be used for air quality planning purposes. Second, consistent with EPA guidance, the model is used in a relative sense to project future year values. EPA suggests that this approach “should reduce some of the uncertainty attendant with using absolute model predictions alone.” Furthermore, the attainment modeling is supplemented by additional information to provide a weight of evidence determination.

Modeled Attainment Test

The UDAQ used the Software for Model Attainment Test - Community Edition (SMAT-CE) v. 1.01 utility from EPA¹⁵ to perform the modeled attainment test for daily PM_{2.5}. SMAT is designed to interpolate the species fractions of the PM mass from the Speciation Trends Network (STN) monitors to the FRM monitors. It also calculates the relative response factor (RRF) for grid cells near each monitor and uses these to calculate a future year design value for these grid cells. A grid of 3-by-3 (9) cells surrounding the monitors was used as the boundary for relative response factor (RRF) calculations.

The State of Utah operates three Chemical Speciation Network (CSN) monitors: Hawthorne, Bountiful, Lindon. Hawthorne is located in Salt Lake County, while Bountiful is in Davis to the North, and Lindon is located in Utah County to the South. Of the three, Hawthorne samples one out of three days, while the other two sample only one in six days.

This mismatch in sampling frequency lead, initially, to interpolated speciation profiles that were unexpectedly non-uniform across the Salt Lake Valley. To create more realistic speciation profiles, the CSN data collected at the Hawthorne monitor were applied to all of the FRM sites in the SLC nonattainment area. UDAQ believes this is a reasonable assumption that is supported by recently conducted special studies. Further discussion may be found in the Technical Support Document.

SMAT results are shown in **Table 6.1** for all projection years as well as the base year 2016.

¹⁵ <https://www.epa.gov/scram/photochemical-modeling-tools>

Monitor ID	Monitor Name	2016 Baseline DV	2017 Milestone FDV	2019 Future DV	2020 Horizon FDV
490030003	Box Elder	31.9	31.9	30.4	29.6
490110004	Bountiful	29.7	29.6	29.3	29.2
490351001	Magna	27.9	27.7	28.0	27.6
490353006	Hawthorne	34.3	34.4	33.8	33.8
490353010	Rose Park	36.3	36.2	35.9	35.6
490570002	Ogden #2	32.4	32.3	32.2	31.9

Table 1: Design values for base year and projected years. Purple numbers highlight design values greater than the NAAQS (35 $\mu\text{g}/\text{m}^3$).

Table 6.1: Design Values for base year and projected years. Purple numbers highlight design values greater than the NAAQS (35 $\mu\text{g}/\text{m}^3$).

Air Quality as of the Attainment Date

The attainment date for this Serious $\text{PM}_{2.5}$ nonattainment area is December 31, 2019.

The plan provisions for serious areas call, in Section 189(b)(1)(A), for a demonstration that the plan provides for attainment by the applicable attainment date, or if impracticable, by the most expeditious alternative applicable date practicable.

As shown in the modeled attainment test, the emissions reductions achievable in 2019 do not conclusively allow for a demonstration that the Salt Lake City, UT nonattainment area will attain the 24-hour $\text{PM}_{2.5}$ NAAQS. Although predictions at ~~seven of the eight~~ all other monitors are less than 35.5 $\mu\text{g}/\text{m}^3$, the predicted concentration at the Rose Park monitor is still above the standard.

Nevertheless, the EPA acknowledges that there is other information that may be considered when determining whether attainment may be reached by the attainment date. This is discussed in the next section.

6.2 Weight of Evidence

The requirement for a plan revision that includes assessment of attainment in Section 189(b)(1)(A) calls for a demonstration, “including air quality modeling.” Despite the heavy reliance of photochemical modeling, there is other information that may be considered when determining whether attainment may be reached by the attainment date. The PM_{2.5} Implementation Rule notes that “the modeling guidance continues to describe the opportunity for states to supplement their modeling with a “weight of evidence” demonstration. States may use other information and analyses, in addition to the modeled attainment test to estimate whether future attainment of the NAAQS in an area is likely. Other analyses may include, but are not limited to emissions trends, ambient data trends and analyses, other modeling analyses and documentation of other non-modeled emissions control strategies including voluntary programs.” The following is an assemblage of such additional evidence in support of attainment by 2019.

Uncertainties in the Analysis

The underlying reason for suggesting other evidence is necessary to assess a finding of attainment, is the inherent uncertainty in a comprehensive analysis such as this. Each subset of information fed to the air quality model is developed using the best information available and steps are taken to minimize bias and uncertainty, but still involves some degree of estimation.

Emissions inventories make up a significant amount of this information. The approved methods of estimating emissions are continually improving, minimizing to a degree the uncertainties involved, and in some cases the information is quite good. Point sources in particular have a long history of testing results. Wherever possible, the actual stack test results or data from continuous emissions monitors is used to describe emissions. Where this is not feasible, measurements at similar sources have resulted in the development of emission factors that provide users with a good degree of confidence. This is particularly true of the criteria pollutants. Emissions from area sources, however, are far less certain. Estimation of emissions from particular categories of area sources has improved, yet the presence of such source categories within any given airshed is difficult to verify. Typically, population (or in some cases acreage) is used as a surrogate to estimate the amount of activity associated with such source categories. Naturally, this assumes a “standard” urban mix of these source categories that is applied to any given area, such as the Wasatch Front. Emissions from mobile sources are estimated through the use of models developed by EPA. EPA’s NONROAD model serves in that role to estimate emissions from mobile sources such as planes, trains, and miscellaneous non-road engines including construction equipment. Some of the information required by this model is easily verified, such as the number of take-offs and landings at each airport. However, much like any area source, the numbers of miscellaneous engines are estimated using population as a surrogate. MOVES2014a is the current model used to describe emissions from on-road mobile source emissions. These models are developed using both laboratory and in use testing, and again they make use of the most recent information available. Yet 2014a is already the 4th version of this model utilized by UDAQ in preparing its implementation plans, and before MOVES there were ten versions of the MOBILE model. Estimations of NO_x have differed significantly as one model replaced the next. Already there is some discussion that MOVES2014a may be

1 underestimating NO_x emissions from heavy-duty diesel vehicles, and that the model may
2 be revised again in the near future. Additionally, the development of the emission factors
3 for ammonia has undoubtedly received far less attention than those for NO_x, VOC, and
4 PM, itself. Another layer of uncertainty associated with the estimation of on-road mobile
5 source emissions originates at the transportation planning process. Agencies responsible
6 for efficient transportation planning employ what are called travel demand models to
7 forecast important parameters such as vehicle miles traveled, vehicle speeds on various
8 roadway types, and the number of trips made by the driving public. These are all
9 parameters that make use of the emission factors generated by the MOVES model.

10 *Meteorological data* is another subset of information necessary to run the air quality
11 model. It becomes necessary in any gridded model to describe the meteorology at the
12 boundary of every single grid cell in order to derive information about emission transport
13 and chemical activity. Naturally it is not practical to situate a weather station at all of
14 these locations, so the met-data that is available must be interpolated to generate the
15 information for the spaces in between. This task is performed with a whole other layer of
16 modeling. While this step in the air quality modeling is performed using the most
17 advanced techniques available, there is still an inherent degree of uncertainty. It is
18 simply not possible to ground-truth the results of the met-modeling. Furthermore, the
19 terrain surrounding the Salt Lake City nonattainment area is very complex due to the high
20 mountains and numerous canyon mouths that allow exchange with air from above in a
21 diurnal pattern.

22 *The Air Quality Modeling* itself is another potential source of uncertainty. In general
23 terms, the air quality model is approved for regulatory purposes and performs well
24 enough in reproducing concentrations experienced in historical episodes to make its
25 predictions in the projection years evaluated herein. Yet, it is still just a model. Any
26 model makes assessments of physical and chemical laws within each of its grid-cells.
27 There is no uncertainty about that. However, the atmosphere itself must be approximated
28 and is certainly more complex than the model can describe. Air quality modeling now is
29 far more accurate than it was in previous decades, but that only implies that there is still
30 room to improve. This is especially the case when considering the understanding and
31 description of photochemistry that is programmed into the model. The Salt Lake City
32 nonattainment area has such a high proportion of secondary chemistry at the heart of its
33 PM_{2.5} problem that any uncertainties associated with the photochemistry will certainly
34 become more prominent than for nonattainment areas that are less complex.

35 Furthermore, and in a synergistic way, our advances in the understanding of the various
36 photochemical pathways to PM_{2.5} also serve to underscore the afore-mentioned
37 uncertainties in the emissions inventory. As certain compounds reveal their importance
38 in these chemical reactions, it becomes clear that they may have been under-prioritized
39 when the inventories were compiled. These inventories have historically concerned
40 themselves with criteria pollutants such as NO_x and SO₂, and as noted they are generally
41 accurate in their assessment of these emissions. Yet it is becoming evident that
42 additional information will be required to support a greater understanding of secondary
43 PM_{2.5} formation. This is discussed in the next two sections.

44 ***Missing HCl and Cl from the Emissions Inventory:*** Both hydrochloric acid (HCl) and
45 aerosol chloride play an important role in PM_{2.5} formation. In the presence of excess
46 ammonia, HCl will partition to aerosol particles, ultimately forming ammonium chloride,

1 which has been shown to account for 10 – 15% of PM_{2.5} mass during high wintertime
2 PM_{2.5} pollution episodes¹⁶. Aerosol chloride can also contribute to the formation of nitryl
3 chloride (ClNO₂), a source of radicals which act to enhance the daytime photochemical
4 production of ozone and nitrate, both of which are important contributors to PM_{2.5}
5 formation. This formation of ClNO₂ is particularly active in the Salt Lake Valley, as
6 shown by recent aircraft measurements (2017 Utah Winter Fine Particulate Study
7 (UWFPS))¹⁷. Measurements of chloride indicate that it is significantly underestimated in
8 the model; however, the sources of HCl and aerosol chloride are unclear, suggesting that
9 significant sources of chloride and HCl are either not included or have been
10 underestimated in the emissions inventory. Potential sources may include the Great Salt
11 Lake, road salt, playa dusts from dry salt beds and the US Magnesium plant. An analysis
12 of chemical speciation data collected at the Hawthorne site over previous years showed
13 that the monthly average sodium ion and chloride concentrations overall increase with
14 snowfall, suggesting that road salt may be a significant contributor to particulate chloride
15 in winter. Emissions from road salt and the Great Salt Lake are not accounted for in the
16 emissions inventory.

17 Measured HCl is also underestimated by the model, particularly in the vicinity of US
18 Magnesium, where values as high as 100 ppb were observed during the 2017 UWFPS¹⁸.
19 By contrast, CAMx expects that only 35ppm would be available to participate in the
20 PM_{2.5} chemistry.

21 This apparent underestimation in chloride and HCl emissions adds uncertainty to the
22 modeling results. By not accounting for these emissions and their impact on PM_{2.5}
23 formation through the availability of various oxidants, the model's sensitivity to NO_x
24 controls may be limited. The model is likely creating an oxidant-limited regime, and may
25 therefore be less responsive to simulated NO_x controls.

26 UDAQ is planning a field sampling campaign during winter 2018-2019 and summer
27 2019 in order to improve the emissions inventory for chloride and HCl.

28 See the Technical Support Document for a more complete discussion of HCl and
29 chloride.

30 ***Uncertainties in Ammonia Emissions:*** Ammonia is a key precursor to ammonium
31 nitrate, the predominant (up to 60%) PM_{2.5} component during persistent wintertime
32 inversion periods in northern Utah. While NO_x emission sources are generally well
33 understood, there are many uncertainties surrounding the origins and distribution of
34 ammonia emissions. This is examined in the following discussion of recent studies and
35 current modeling progress.

36 ***2017 Utah Winter Fine Particulate Study Results:*** The scope of the UWFPS included all
37 three air basins in northern Utah that are presently designated nonattainment for the 2006
38 24-hour PM_{2.5} NAAQS. Each of these nonattainment areas sees elevated concentrations
39 of secondary PM as a result of cold pool meteorology. The study indicates that each of

¹⁶ Kelly, K.E., R. Kotchenruther, R. Kuprov, and G.D. Silcox, Receptor model source attributions for Utah's Salt Lake City airshed and the impacts of wintertime secondary ammonium nitrate and ammonium chloride aerosol. Journal of the Air & Waste Management Association, 2013. 63(5): p. 575-590.

¹⁷ <https://www.esrl.noaa.gov/csd/groups/csd7/measurements/2017uwfps/finalreport.pdf>

¹⁸ <https://www.esrl.noaa.gov/csd/groups/csd7/measurements/2017uwfps/finalreport.pdf>. Chapter 3.

these areas is most commonly nitrate limited (2017 UWFPS Final Report¹⁹). These findings are based on measurements made both on the ground and aloft. However, of the three basins, the Salt Lake Valley is nitrate limited to the least degree, exhibiting generally the largest ratio of total nitrate to reduced nitrogen. Measurements also show the Salt Lake Valley as having lower concentrations of ambient ammonia than the other two areas. This is illustrated in **Figure 6.10** with a comparison between Salt Lake and the Cache Valley. Concentrations in the Provo nonattainment area would likely sit between these other two.

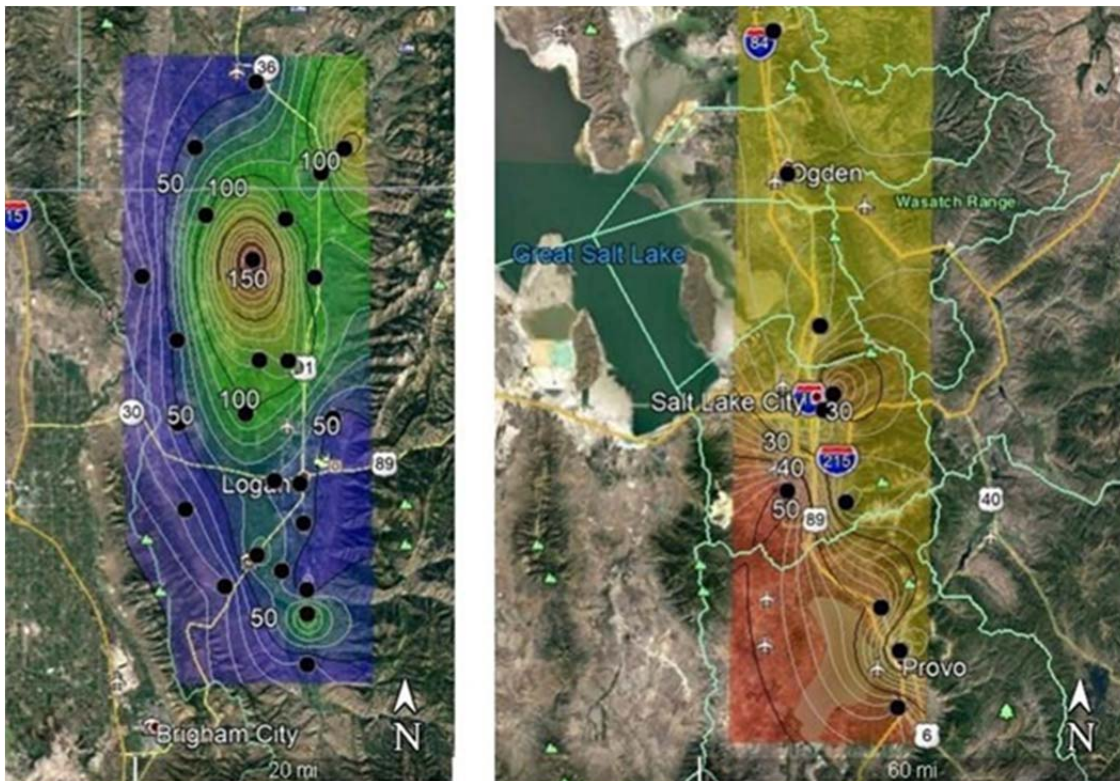


Figure 6.10: Contour plots of average ambient NH₃ concentrations [ppb] for Cache Valley and the Wasatch Front during the 2017 UWFPS. Panel comparison shows concentrations were much lower in the Salt Lake Valley (right) than Cache Valley (left). Sampler locations are depicted by black dots.

However, the emission inventory compiled for ammonia does not reflect these observed regional differences. This can be seen in **Figure 6.11**, where ammonia emissions for all three air basins appear to be more or less within the same range.

¹⁹<https://documents.deq.utah.gov/air-quality/planning/technical-analysis/research/northern-utah-airpollution/utah-winter-fine-particulate-study/DAQ-2018-004037.pdf>

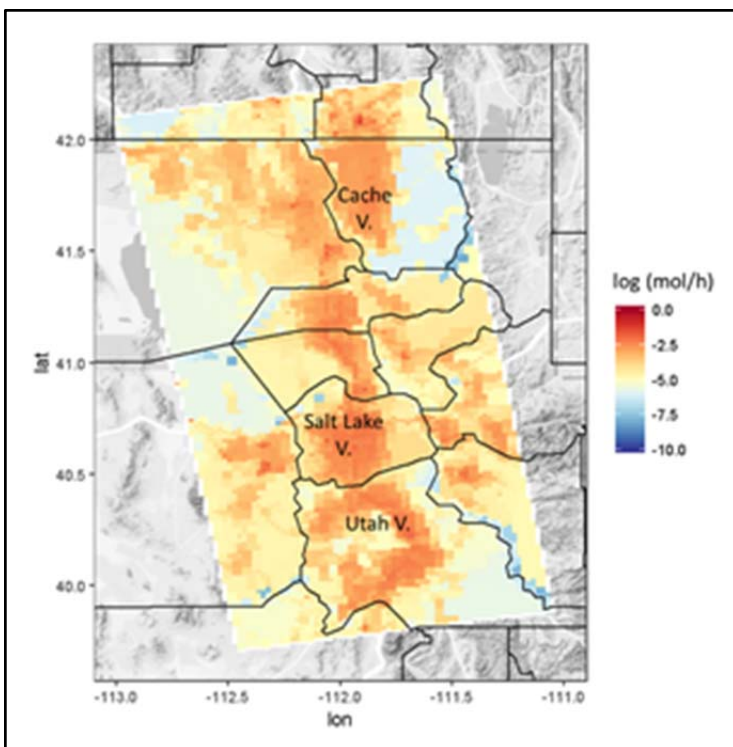


Figure 6.11: 24-hour average of 2014 NEI NH₃ emission rates (moles/hr) allocated across a 1.33 km Northern Utah modeling domain. Emission rates reflect a typical winter weekday in February. Ammonia injection is not included as to highlight the current state of the Utah ammonia emissions inventory.

Clearly, there is an inconsistency between the discernable information presented in **Figures 6.10 and 6.11**. Furthermore, using the emission inventory for ammonia depicted in **Figure 6.11**, CAMx was not able to re-create the observed concentrations of ammonium nitrate.

Ammonia injection: Recognizing that the emission inventory for ammonia was likely not very accurate, this discrepancy was addressed by adjusting the inventory until model results aligned more closely with the actual observations. This is achieved by artificially “injecting” non-inventoried ammonia emissions into the air quality model alongside the inventoried emissions.

In order to match modeled ammonia with observations at controlling nonattainment monitors, UDAQ used information from 2016 ammonia measurements (Dr. Randy Martin, Utah State Univ.) to determine how much ammonia would need to be injected. To account for the spatial differences observed through measurement, the injected ammonia is varied on a county-to-county basis. Also, ammonia is only injected in relatively low elevation areas (< 6,000 ft ASL) in order to better associate the missing ammonia with anthropogenic sources.

Ammonia deposition: Within the modeled simulation, ammonia is emitted and there is a temporal rate ascribed to the emissions. There is also however, an ascribed rate at which ammonia is removed from the system through deposition onto the ground. It is the combination of these two rates that determines the overall abundance of ammonia that would be available to participate in chemical reactions that lead to ammonium nitrate.

1 Early runs with the model were not able to re-create the concentrations of ammonium
2 nitrate that were observed at the monitoring stations. It seemed this was likely due to a
3 deposition rate that was too high, and more specifically that the modeled resistance to
4 such deposition was characterized as too low.

5 To address the high ammonia dry deposition rate in the air quality model, UDAQ
6 modified CAMx to maximize surface resistance to ammonia and keep as much free
7 ammonia available for chemistry as possible²⁰.

8 While it may be relatively simple to adjust the rates of deposition, and resistance thereto,
9 it is important to keep in mind that the real world is far more complex than what is
10 presently characterized in the model. The CAMx model does not currently account for
11 the re-volatilization of ammonia. Re-volatilization occurs when some forms of nitrogen
12 (e.g., urea) changes to an ammonia gas. Ammonia is then transported from soil and
13 emitted to the atmosphere.

14 *Why it matters to Utah air quality modeling:* Like the 2017 Utah Fine Particulate Study
15 (UWFPS) observations, UDAQ PM_{2.5} modeling also shows that the highest sensitivity to
16 ammonia is in Salt Lake Valley. This is perhaps due to the abundance of NO_x emissions
17 in the Salt Lake Valley compared to elsewhere in Utah. The Salt Lake Valley is more
18 urban and features a relatively small animal husbandry sector compared to Cache Valley.
19 The high abundance of NO_x emissions suggests that ammonia potentially plays a more
20 important role in secondary PM_{2.5} formation.

21 In the absence of any reliable measurements of ambient ammonia, the model
22 performance was used as an indicator of how much ammonia would be injected. In the
23 final configuration, fully 40% of the emission inventory was artificially introduced into
24 the SLC nonattainment area. This represents a large portion of ammonia about which
25 nothing is really known. The spatial location of its release and its deposition are
26 unknown. The temporal characteristics of its abundance are also poorly understood. This
27 includes any daily or seasonal fluctuations. By contrast, NO_x, the other chief constituent
28 of ammonium nitrate is very well characterized in both space and time. NO_x emissions
29 from motor vehicles are spatially distributed within the model to reflect the network of
30 roadways, and it is temporally reflective of vehicle usage by the hour of each day of the
31 week. Point sources of NO_x are precisely located on the grid, and include parameters that
32 affect its release such that a vertical distribution may also be assigned. Each source also
33 reports its hours of operation such that these emissions may be assigned a temporal
34 profile. This is the level of characterization expected in an analysis of this type, yet where
35 ammonia is concerned we see only a static quantity of homogenous distribution.

36 Furthermore, it is not possible to consider any long-term trends in ammonia emissions.
37 Therefore, unlike any of the other precursor pollutants, the amount of injected ammonia
38 is assumed to be identical in both base-year and future-year inventories. This has
39 importance beyond the relatively short span of time evaluated in the analysis for this SIP.
40 Downward trends in NO_x emissions are well established, and as will be discussed in
41 **section 6.9**, have been coincident with downward trends in PM_{2.5} concentrations. Since
42 such trends in PM_{2.5} are skewed by elevated wintertime concentrations it seems likely
43 that the SLC airshed has for a long time existed in a chemical regime that is in fact NO_x

²⁰ Recent versions of CAMx released by Ramboll now maximize the surface resistance to ammonia in order to lower the ammonia dry deposition rate. However, bidirectional flux is still not emulated in the model physics at this time.

1 (or in past times SO₂) limited. As noted above, this is also the conclusion of the UWFPS,
2 although by comparison to Utah's other two airsheds perhaps less so. Certainly this is not
3 a static condition, yet because of the uncertainties surrounding the origin of ammonia
4 emissions, model projections into the future are left to compare trends in NO_x against a
5 static quantity of ammonia. This should lead to some caution in accepting any prediction
6 concerning a near-term change from what has been a NO_x limited environment to one
7 that is limited by ammonia. This is perhaps especially so if such chemical regimes are
8 described now with a resolution that varies by the hour of the day. The effect of holding
9 the amount of injected ammonia constant potentially makes the model stiff and
10 unresponsive to modeled reductions in NO_x emissions.

11 Although the 2017 UWFPS was helpful, more observational studies are needed to further
12 our understanding of ammonia in Salt Lake Valley. The lack of reliable measurements of
13 ammonia impairs UDAQ's ability to properly characterize ammonia in the atmosphere
14 and thus, provides a weak basis for making improvements in Utah's ammonia emissions
15 inventory.

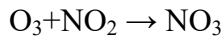
16 To help address some of this uncertainty, UDAQ plans to take ambient measurements of
17 gaseous ammonia and hydrochloric acid (HCl) during the winter of 2018/2019 and the
18 summer of 2019. Passive sampling will be focused on the Wasatch Front; twenty
19 samplers alone placed within the Salt Lake City airshed. Additional measurements of
20 PM_{2.5} distribution and composition as well as mobile measurements of temporally-refined
21 ammonia will also be conducted.

22 ***Missing Nitryl Chloride Chemistry Pathway in CAMx:*** Beyond the uncertainties in the
23 emission inventories that support the analysis, other uncertainties within the air quality
24 model itself also warrant some discussion. Recent measurements have shown that nitryl
25 chloride (ClNO₂) formation, through the heterogeneous uptake of N₂O₅ onto particles
26 containing chloride, is particularly active in the Salt Lake Valley. However, this is not
27 accounted for in the carbon bond chemistry mechanisms within CAMx.

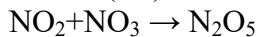
28 Halogens play an important role in PM_{2.5} formation during wintertime inversion episodes.
29 They act as radical sources important for the photochemical production of PM_{2.5}. ClNO₂,
30 in particular, is an important source of radicals for daytime photochemical production of
31 ozone and nitrate, as shown by recent aircraft measurements conducted in the Salt Lake
32 Valley (2017 UWFPS²¹). These measurements showed that ClNO₂ is typically elevated
33 over the Salt Lake City and Provo urban regions, reaching mixing ratios greater than 0.8
34 ppb at night. Similar levels of ClNO₂ were also detected in the plume of the U.S.
35 Magnesium plant. These measurements also suggested that the chemical pathway₂ where
36 ClNO₂ is formed through the heterogeneous uptake of N₂O₅ on chloride-containing
37 particles₂ is particularly active in the Salt Lake Valley, where ammonium chloride aerosol
38 generally accounts for 10 – 15% of PM_{2.5} mass during high-PM_{2.5} episodes²². This
39 formation of ClNO₂ occurs mainly at night since the formation of N₂O₅, which is
40 produced by a chemical reaction involving NO₂ and NO₃, is suppressed during the day
41 (R1-R3).

²¹ <https://www.esrl.noaa.gov/csd/groups/csd7/measurements/2017uwfps/finalreport.pdf>

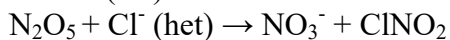
²² Kelly, K.E., R. Kotchenruther, R. Kuprov, and G.D. Silcox, Receptor model source attributions for Utah's Salt Lake City airshed and the impacts of wintertime secondary ammonium nitrate and ammonium chloride aerosol. Journal of the Air & Waste Management Association, 2013. 63(5): p. 575-590.



2 (R1)



4 (R2)



6 (R3)

7 Once produced ClNO_2 will then photolyze into chlorine radicals and NO_x , thereby
8 contributing to the oxidant budget and NO_x recycling.

9 However, while this heterologous pathway for N_2O_5 uptake on Cl-containing particles is
10 potentially important for $\text{PM}_{2.5}$ formation in the Salt Lake Valley, the carbon bond
11 chemistry mechanisms in CAMx, including cb6r2h that was used in UDAQ's
12 simulations, do not include this pathway. Given ClNO_2 's role in contributing to the
13 oxidants budget, an exclusion of this pathway in CAMx may increase the model's
14 sensitivity to oxidants and may limit its sensitivity to NO_x emissions. Without this
15 pathway, the model may be less responsive to proposed NO_x controls.

16 **Misrepresentation of Formaldehyde in the Model:** The model's sensitivity to changes
17 in NO_x emissions may be obscured by an under-estimation of formaldehyde during mid-
18 day hours.

19 Carbonyls, such as formaldehyde, act as radical sources which are important for the
20 photochemical production of $\text{PM}_{2.5}$ during wintertime inversion episodes in the Salt Lake
21 Valley. The photolysis of these compounds may be important for daytime generation of
22 radicals, as shown by recent observations^{23,24}. However, although formaldehyde is
23 important for $\text{PM}_{2.5}$ formation, it may be underrepresented in the model during mid-day
24 hours. Given that measurements of VOC species were not available during 2011, the
25 modeling results were compared to observations conducted in winter 2017 at the
26 University of Utah (2017 UWFPS). While these field study measurements from 2017
27 cannot be directly compared to day-specific 2011 model simulations, they're qualitatively
28 useful to assess if the model predicts similar levels of VOCs during strong inversion
29 conditions.

30 On average during peak $\text{PM}_{2.5}$ exceedance days, measured formaldehyde peaked at about
31 3 ppb around 11 am (**Figure 6.11**) while modeled formaldehyde displayed a
32 concentration of 1.8 ppb (**Figure 6.10**) at 11 am. Modeled formaldehyde also displayed a
33 temporal trend different from that of measured formaldehyde, with observations
34 indicating direct emission as well as secondary production of formaldehyde. Similarly,
35 modeled acetaldehyde exhibited a temporal trend different from that measured on peak
36 $\text{PM}_{2.5}$ days. This comparison suggests that acetaldehyde and formaldehyde, an important
37 source of radicals, may be underestimated in the model during mid-day hours. Given the
38 role of formaldehyde in the generation of radicals, an underestimation of formaldehyde in
39 CAMx may increase the model's sensitivity to oxidants.

²³ Baasandorj, M., S.W. Hoch, R. Bares, J.C. Lin, S.S. Brown, D.B. Millet, R. Martin, K. Kelly, K.J. Zarzana, C.D. Whiteman, W.P. Dube, G. Tonnesen, I.C. Jaramillo, and J. Sohl, Coupling between Chemical and Meteorological Processes under Persistent Cold-Air Pool Conditions: Evolution of Wintertime $\text{PM}_{2.5}$ Pollution Events and N_2O_5 Observations in Utah's Salt Lake Valley. Environmental Science & Technology, 2017. 51(11): p. 5941- 5950

²⁴ <https://www.esrl.noaa.gov/csd/groups/csd7/measurements/2017uwfps/finalreport.pdf>. Chapter 3.

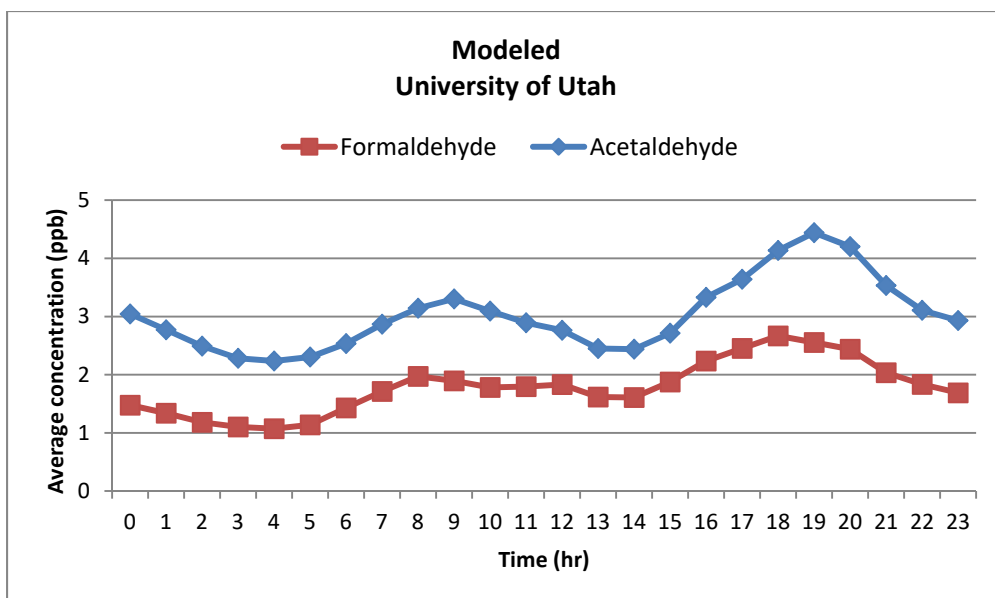


Figure 6.12: Hourly time series of average modeled formaldehyde and acetaldehyde during January 6-8 2011 at the University of Utah.

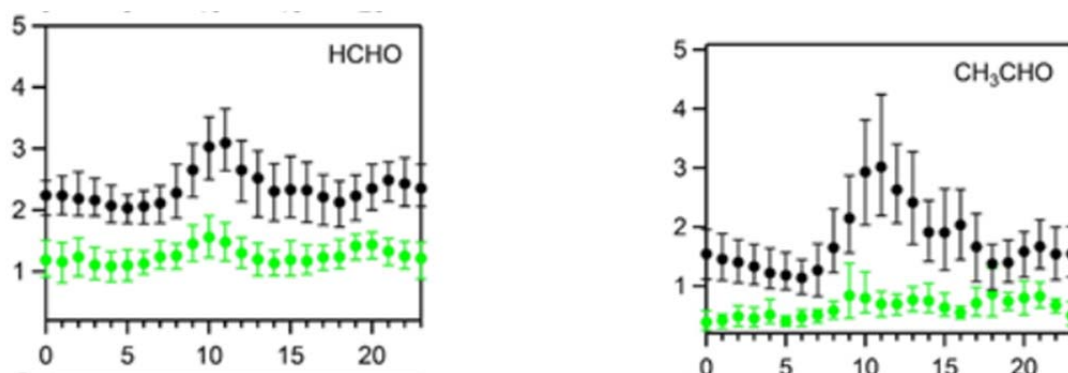
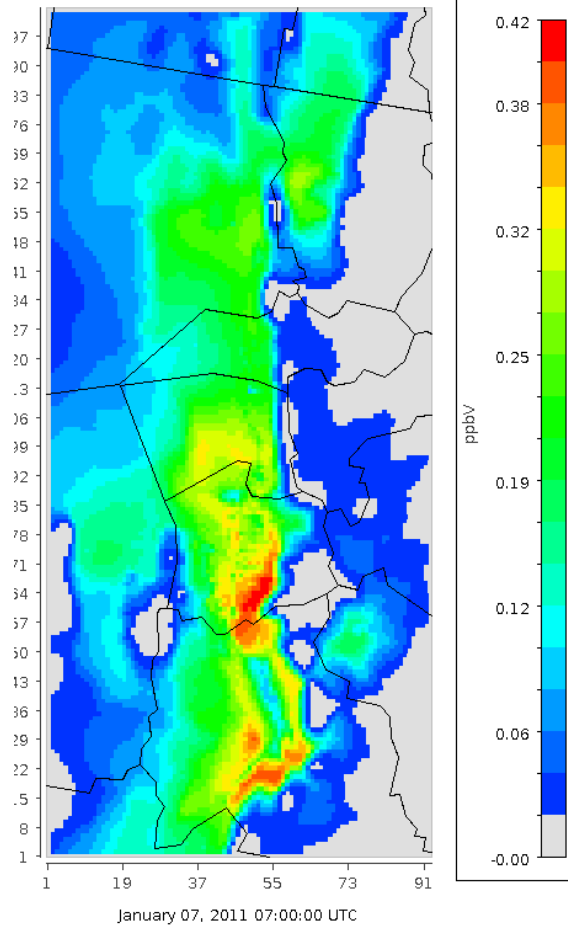


Figure 6.13: Diurnal trend of hourly averaged formaldehyde (HCHO) and acetaldehyde (CH₃CHO) measured at the University of Utah during polluted (black lines) and clean (green lines) conditions in winter 2017. Figure retrieved from the 2017 Utah Winter Fine Particulate Study, final report, Figure 3.59 (<https://www.esrl.noaa.gov/csd/groups/csd7/measurements/2017uwfps/finalreport.pdf>).

The model's sensitivity to formaldehyde emissions was further evaluated by conducting a modeling sensitivity run where formaldehyde emissions from all sectors were increased by 50%. Formaldehyde emissions from the 2019 inventory were considered for this sensitivity simulation. Both modeled ozone and nitrate (**Figure 6.14**) increased after increasing formaldehyde emissions, suggesting that the model is oxidant-limited and may have a limited sensitivity to a reduction in NO_x emissions. An underestimation of formaldehyde will lead to an underestimation in the production of HNO₃, leading to a reduced response to proposed NO_x controls.

Difference in O3

Sensitivity - 2019 emissions modeling run



1

Difference in nitrate

Sensitivity - 2019 emissions modeling run

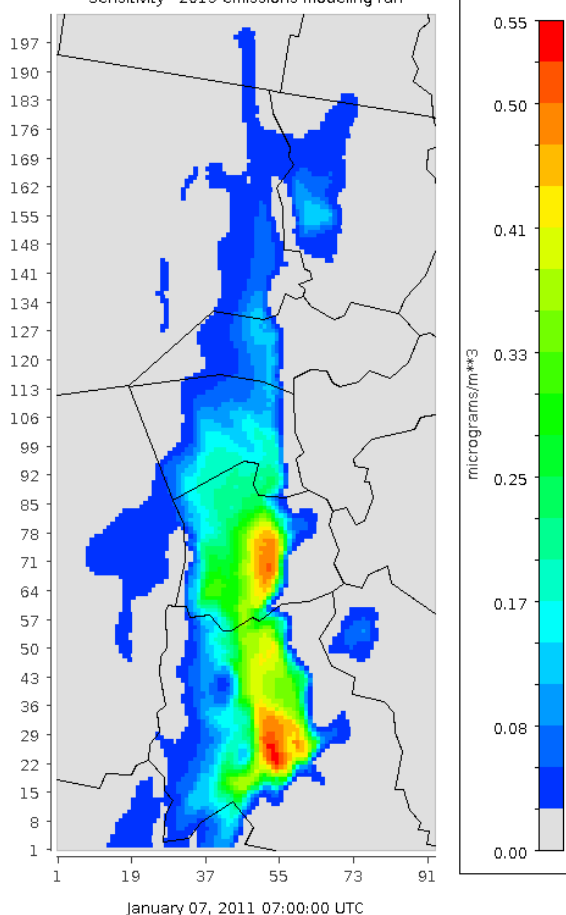
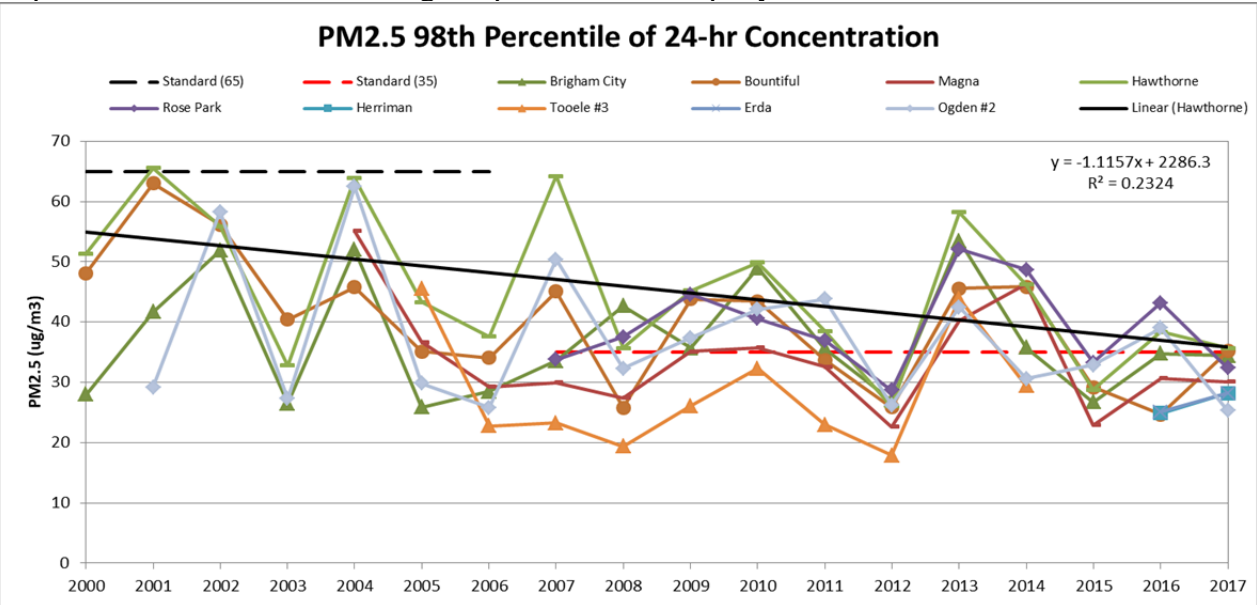


Figure 6.14: Spatial plots of the difference in mean ozone and nitrate levels between the sensitivity modeling run, where formaldehyde 2019 emissions were increased by 50%, and the 2019 emissions modeling run, where formaldehyde emissions were kept unchanged. Plots are shown for January 7 2011.

Trends in Monitored Data

Certainly the most significant information to assess would be the ambient air quality data collected throughout the nonattainment area, and in particular, any observable trends in the data. The Salt Lake City nonattainment area is designated such only for the 24-hour health standard, so it should be simple to focus on the 24-hour $PM_{2.5}$ values. This, however, is somewhat confounding because of the nature of the problem. As described in Section 1.3, concentrations in excess of the 24-hour NAAQS are only incurred during winter months when cold-pool conditions drive the formation of and trap secondary $PM_{2.5}$. The actual cold-pool temperature inversions vary in strength and duration from year to year, and the $PM_{2.5}$ concentrations measured during those times reflect this variability far more than they reflect gradual changes in the emissions of $PM_{2.5}$ and $PM_{2.5}$ precursors. This variability may easily be seen in **Figure 6.15** below. Still, if one fits a line through the data collected at the Hawthorne site, the NCORE site for the SLC

1 metropolitan statistical area, the trend is noticeably downward and indicates an
2 improvement of about one microgram per cubic meter, per year.



3
4 **Figure 6.15 Trend in Monitored PM2.5 (98th Percentiles of 24-hour Concentrations)**

5
6

This episodic variability is generally removed by looking at annual mean values of PM_{2.5} concentrations as shown in **Figure 6.16**. This data is still skewed more by winter data than summer data. It includes all of the high values identified as the 98th percentiles, as well as the values ranked even higher. Still the trend is downward. Fitting a line through the data collected at the Hawthorne site reveals a trend that is noticeably downward, and indicates an improvement of about 4.5 micrograms per cubic meter, over the 17-year span. Such improvement is noteworthy in the face of this area's rapid growth in both population and vehicle miles traveled (vmt).

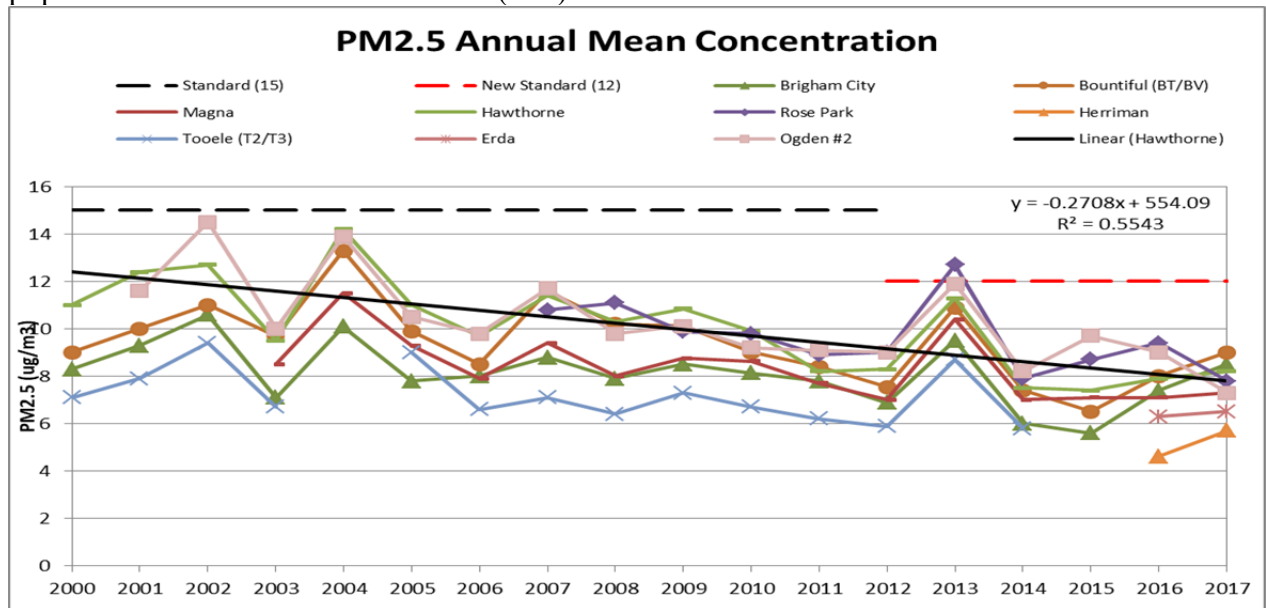


Figure 6.16 Trend in Monitored PM_{2.5} (Annual Mean Concentrations)

UDAQ also monitors two of the four PM_{2.5} precursors, NO_x and SO₂, and it is also useful to observe the trends in their concentrations.

Figures 6.17 and 6.18 chart trends in nitrogen dioxide, from which NO_x concentrations may be inferred. Whether measured as peak concentrations or long-term averages, the trend has remained steadily downward for a long time.

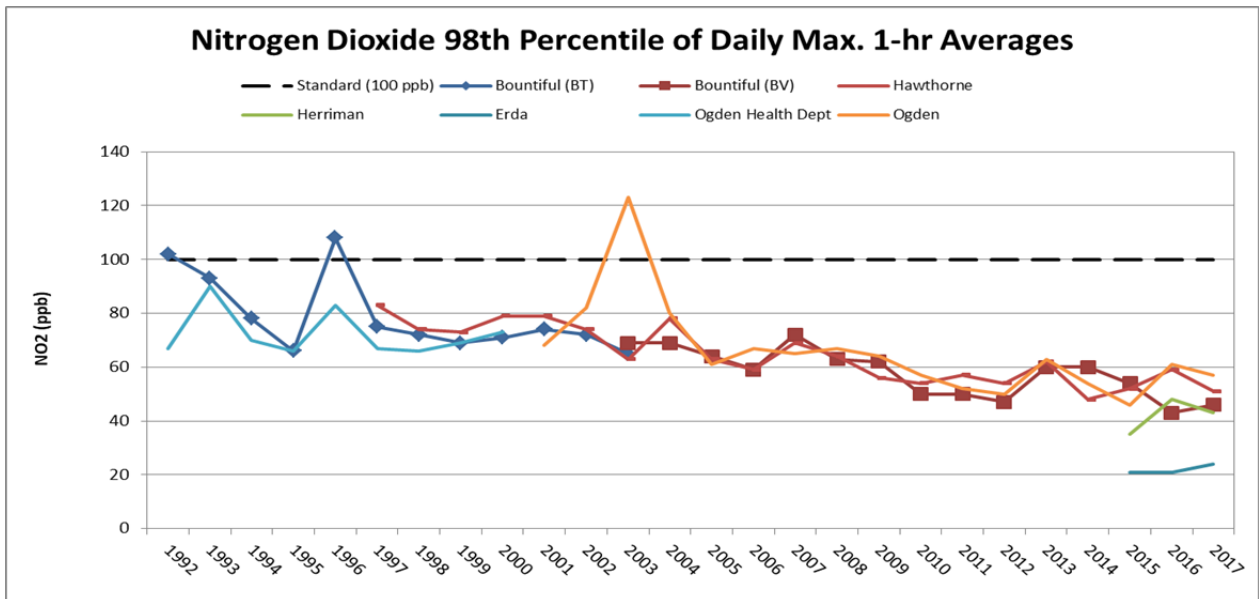


Figure 6.17 Trend in Monitored NO2 (98th Percentiles of Daily 1-hour Max.)

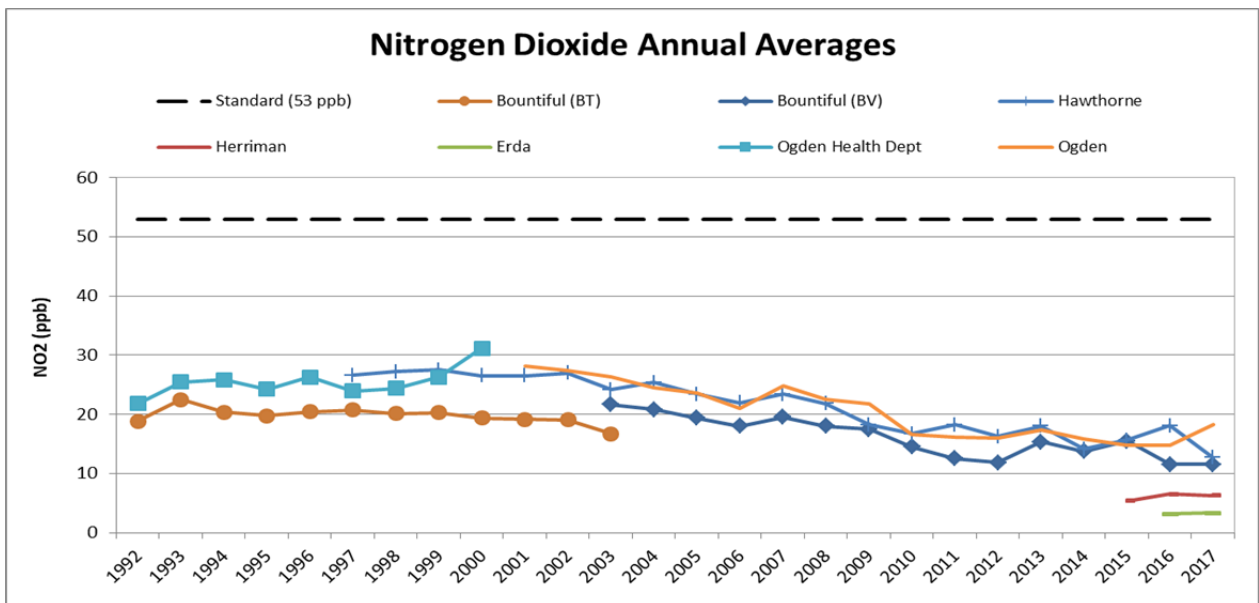


Figure 6.18 Trend in Monitored NO2 (Annual Averages)

Sulfur dioxide has also diminished over time, from a sharp decline in the 1990s to a steady degree of progress over the last 20 years. This is shown in Figure 6.19.

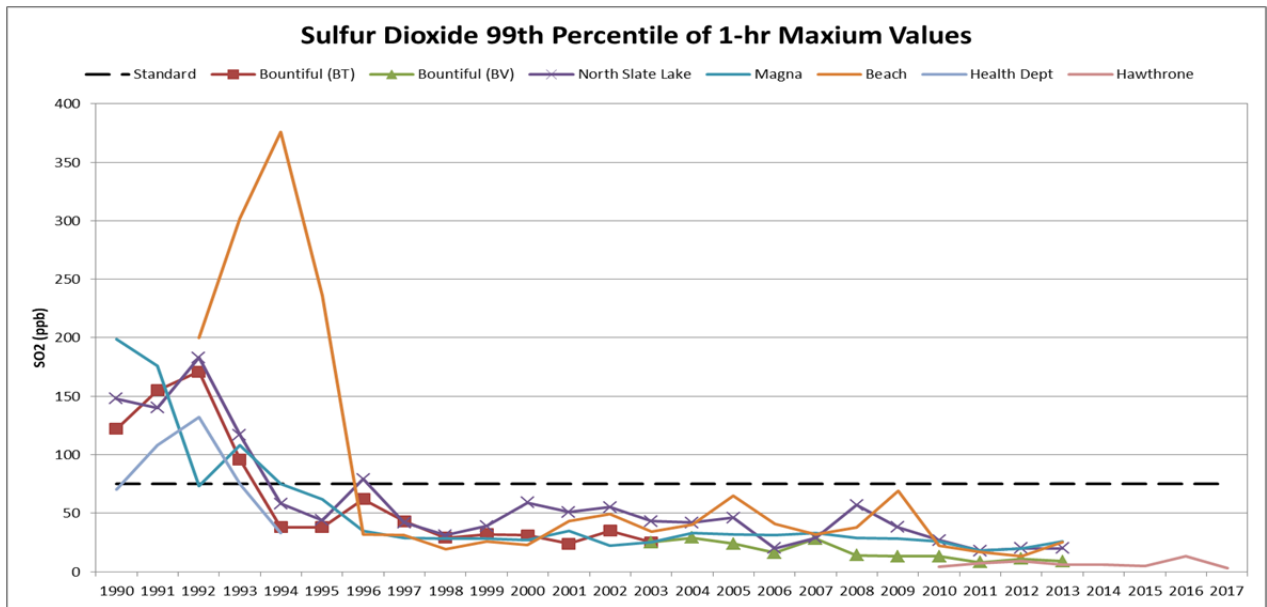


Figure 6.19 Trend in Monitored SO₂ (99th Percentiles of Daily 1-hour Max)

Trends in Emissions

Another way to evaluate trends in air quality is to compare inventories of emissions on a periodic basis. For purposes of this SIP, UDAQ has developed a suite of emissions inventories for several years between 2011 and 2024. These inventories are based on the 2014 tri-annual emissions inventory and are tailored to suit wintertime conditions pertinent to this SIP. Specifically, these emissions inventories reflect winter weekday emissions for all five Salt Lake nonattainment area counties and include parts of the counties that are outside the nonattainment boundary. For this reason, the values shown here may not match nonattainment area emissions summaries shown elsewhere in this document. Still, these emission inventories provide a useful tool for comparing emissions trends over time.

Figure 6.20 below charts the emissions of NO_x, VOC, PM_{2.5} and SO₂ throughout the period of time represented in some way by this Serious Area SIP.

Because wintertime emissions inventories are unavailable prior to 2011, it is useful to consider the tri-annual emissions inventories routinely compiled by UDAQ to evaluate longer-term emissions trends.

Annual emissions trends from the 1999-2014 tri-annual inventories for the five Salt Lake nonattainment area counties are shown in **Figure 6.21** below.

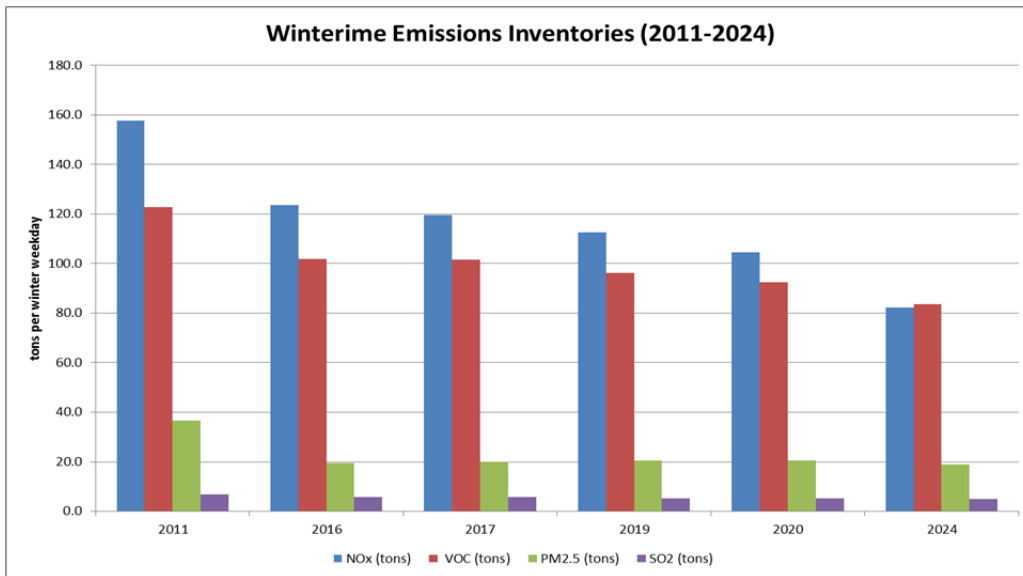


Figure 6.20 Emissions Trends (2011 – 2024)

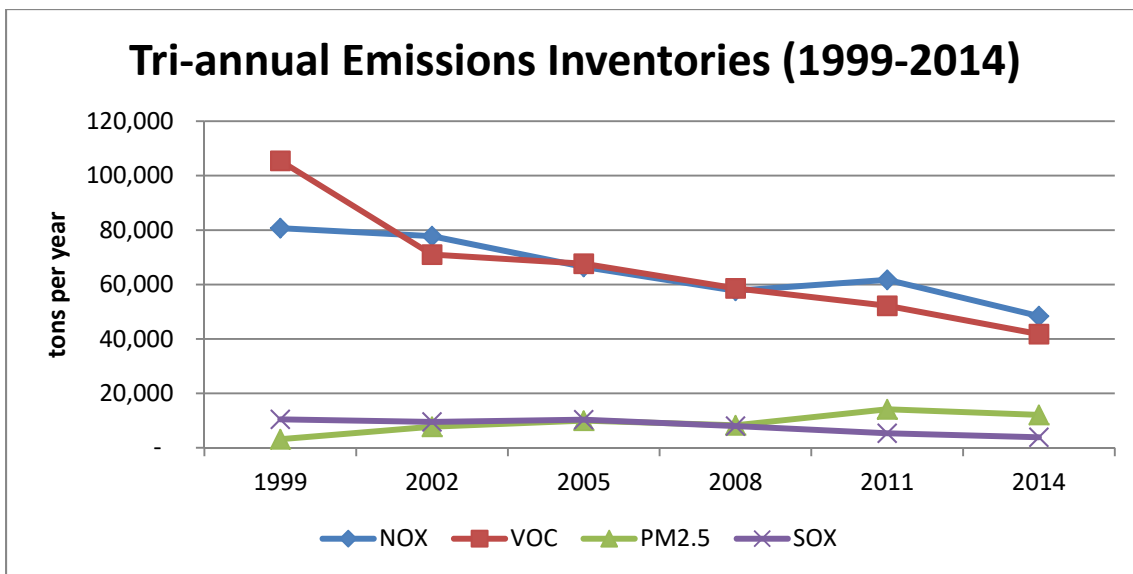


Figure 6.21 Emissions Trends (1999 – 2014)

Seen together, **Figs. 6.20 and 6.21** illustrate trends in $PM_{2.5}$ and $PM_{2.5}$ precursor emissions that reach back almost as far as the establishment of $PM_{2.5}$ as the indicator of fine particulate matter. Qualitatively, it is easy to see that NO_x and VOCs are emitted in much larger quantities than are $PM_{2.5}$ or SO_2 . Also, the trend in each of these $PM_{2.5}$ precursors has been steadily downward for roughly the last 20 years. This is largely attributable to Tiers 1 and 2 of the federal motor vehicle control program, but there are other drivers. Looking back at the trend charts showing ambient NO_x concentrations (**Figures 6.17 and 6.18**), one finds good agreement between the diminishing emissions and the ambient NO_x .

1 UDAQ does not monitor ambient concentrations of VOC, but one would assume that the
2 reductions in VOC emissions would be detected as a continuous trend over this same
3 period.
4 Where SO₂ is considered, it is again useful to refer back to **Figure 6.19** where the
5 ambient concentrations are charted. Here one may observe that by 1999 the airshed had
6 seen an end to what had been a history of NAAQS violations due to very large emissions
7 of SO₂ at a local copper mine. This decline in ambient concentrations was driven first by
8 a SIP addressing SO₂ itself in 1982, and then by a focus on SO₂ control in a 1992 PM₁₀
9 SIP that required SO₂ reductions at not only the copper smelter, but also five oil refineries
10 and a steel mill. From 1999 forward, SO₂ emissions and SO₂ concentrations have
11 remained relatively flat, perhaps trending slightly downward, but at levels that might be
12 described as “background”.
13 PM_{2.5} emissions have also remained somewhat constant over this period, perhaps even
14 trending upward. It is instructive, therefore, to refer back to **Figs. 6.15 and 6.16** showing
15 the monitored trends in ambient PM_{2.5} concentrations.
16 Both of these charts show that PM_{2.5} concentrations have been declining over the same
17 span of time depicted in the emissions trends charts.
18 Taken together, this would suggest that the persistent decline in NO_x and VOC emissions
19 is most directly responsible for the commensurate improvement in PM_{2.5} concentrations,
20 particularly with respect to the secondary PM_{2.5} that dominates the highest exceedances.
21 Throughout any calendar year, PM_{2.5} concentrations in Northern Utah exhibit a
22 background level well beneath the annual standard, marked by episodes of very high
23 concentrations predominantly in the months of December through February which are
24 dominated by secondary PM_{2.5} (**as shown in Figure 6.2.2**),. Since the early 1990s, Utah
25 has addressed these “spikes” in fine particulate by focusing emission control on precursor
26 emissions (SO₂, and NO_x), and maintained that by reducing the magnitude of such
27 exceedances that the annual standard (which has never been violated) would be kept in
28 check. This seems to have been supported by the data concerning both emissions and
29 concentrations.
30 Over this same period of time, it has always been assumed that the Salt Lake City airshed
31 was NO_x (or even SO₂) limited with respect to the atmospheric chemistry that supports
32 formation of secondary PM during periods of cold pool meteorology.
33 Looking forward at the emissions projected in **Figure 6.20**, one will see a continuation of
34 the trends of NO_x and VOC emissions, from the present out to 2024. Again, this reflects
35 the continued implementation of Tier 2 standards and now the introduction of Tier 3.
36 Given the apparent co-benefit of ambient PM_{2.5} improvement between 2000 and 2017,
37 one would expect this co-benefit to continue between now and 2024.
38 Additionally, direct PM_{2.5} emissions are projected to decrease from 20.5 tons per winter
39 weekday in 2019 to 19.0 tons per winter weekday in 2024, and SO₂ emissions are
40 projected to decrease from 5.2 tons per winter weekday to 4.9 tons over the same span.

41 Supplemental Analyses

42 *Additional Modeling Result / Exceptional Event*

43 As discussed in Chapter 3, data captured during the years important to the SIP was
44 initially found to be invalid for a number of reasons, including some values identified by

UDAQ is perhaps being influenced by exceptional events (EEs). EPA's Exceptional Events Rule allows for data that has been heavily influenced by wild land fires, fireworks, etc. to be excluded from the data set in its use for regulatory purposes. The rule requires that states first identify such incidences by affixing a flag to the data it submits, and then submit supporting documentation for EPA to consider. If EPA concurs with the state, it will affix a second flag to the value.

As mentioned already in the discussion surrounding **Tables 3.1 and 3.2**, UDAQ has flagged several values in 2017 that have yet to be concurred with, but with agreement from EPA, excluded these values from the Monitored Design Value (MDV) calculations. There is, however, another value in 2015 that may warrant additional scrutiny. August 20, 2015 was a day influenced by wildland fire. In fact, UDAQ flagged and documented a number of values affected by that event at other monitoring stations (Logan, Brigham City and Ogden). Although smoke from wildfires filled all of Northern Utah, only these three monitors recorded exceedances of the NAAQS. UDAQ; however, UDAQ believes that all monitors in Northern Utah were impacted by smoke.

Even though monitored values at Rose Park were impacted by the smoke event, UDAQ did not flag the value collected at Rose Park because those values did not exceed the standard. This value presently sits as the 8th highest value collected at Rose Park during 2015, and is identified as the 98th percentile value for that year. The reason this value was not flagged is because, at 33.3 µg/m³, it did not exceed the 24-hr NAAQS; perhaps an oversight on the part of UDAQ.

Nevertheless, if this value were to be documented as an exceptional event, the 98th percentile value for Rose Park would become the next highest value which was measured as 31.2 µg/m³, a difference of 2.1 µg/m³. Furthermore, when averaged with the 98th percentile values for 2016 and 2017, the 3-year Monitored Design Value (MDV) for Rose Park would drop from 36.3 to 35.6 µg/m³.

Taking the next step and applying the Relative Response Factor (RRF), calculated for 2019 by the CAMx model, to the reduced MDV, would yield a lower prediction for the future concentration in 2019. This is shown in **Table 6.2**.

Rose Park Monitor	98th Percentile Values (µg/m ³)			2016 Baseline DV	2019 Future DV
	2015	2016	2017		
As presented in Table 6.1	33.3	43.2	32.4	36.3	35.9
Excluding data from 8/20/15	31.2	43.2	32.4	35.6	35.2

Table 6.2 Air Quality Modeling Results; as affected, or not, with the inclusion of data potentially qualifying as an Exceptional Event

The predicted concentration at Rose Park for 2019, the attainment year, was just over the NAAQS at 35.9 µg/m³ (see **Table 6.1**). This of course was the controlling monitor within the nonattainment area, and accounted for the only value in the analysis that was over the 24-hour standard.

Using the new MDV, with the value for August 20, 2015 excluded as an EE, would change the prediction for 2019 to 35.2 µg/m³ and change the conclusion of the modeling

1 result to a likelihood of attainment by 2019 (35.5 rounds up to 36... numbers below 35.5
2 round to 35).
3 How likely is it then, that this value could actually be excluded as an EE? It's true that
4 33.3 does not exceed the 24-hour standard (35 µg/m³), and for only this reason did
5 UDAQ not include the value for Rose Park in the documentation compiled for that event,
6 yet it is greater than the annual NAAQS.
7 EPA has acknowledged that even if a value does not exceed the standard for a 24-hr
8 averaging period, it may still affect a determination of compliance with the 24-hr
9 standard. This is certainly true of the PM_{2.5} standard, where the form of the standard
10 requires the averaging of three distinct 24-hr values. In such cases, EPA indicates that
11 the level of a longer averaging period, in this case the annual standard, can serve as the
12 cut-point for whether the rule may be used to determine that the value was influenced by
13 an exceptional event. In fact, this interpretation was codified into the EE rule, but not
14 until 2016, after the event in 2015.
15 Whether in fact this value receives additional attention in the data set, it remains pertinent
16 to a discussion surrounding a weight of evidence to be considered in the assessment of
17 whether attainment of the PM_{2.5} standard can likely be reached by the attainment date in
18 2019.

19 Overstated Conservatism in Projected Emissions:

20 We have mentioned some of the uncertainties inherent in the modeled demonstration of
21 attainment already. However, there is another aspect of the analysis that bears some
22 mention, and that is the conservatism that is also built into such a demonstration.
23 The SIP is a legal document, with consequences to be enforced in the event certain
24 conditions are not met. For this reason a certain amount of conservatism is built into the
25 estimates used to construct the attainment demonstration, its quantitative foundation.
26 Thus, the discussion herein is not to suggest that such conservatism is misplaced. Rather
27 it is to help, in the context of evaluating a weight of evidence, where perhaps one might
28 give more or less weight.
29 The aforementioned conservatism might be broken into two distinct categories: 1)
30 overstating the emissions to be expected throughout the projection years, and 2)
31 omission of some controls that are expected to help mitigate PM_{2.5} concentrations, but
32 which may not be suited to the assignment of SIP credit. Examples of each are presented
33 below.
34 Emissions from Point Sources – are depicted differently in the base-year inventory than
35 they are in the projection-years. Actual emissions are used in the base-year, whereas the
36 SIP takes more of a worst-case view of these emissions in the projection years and uses in
37 some cases the legal potentials to emit. While this makes legal sense, it tends to overstate
38 a somewhat artificial “growth” in emissions from this sector.
39 Actually, most point sources included in this analysis were already operating in the base
40 year at or near their potentials to emit. Therefore, emissions from these sources remained
41 essentially flat throughout the analysis period.
42 Emission totals for the point source category did in fact exhibit some growth between
43 2016 and 2019. PM_{2.5}, NO_x, and VOC emissions increased by 20, 14, and 13 percent.
44 Virtually all of this increase is shown to be associated with three sources that were not

operating near their respective PTEs in 2016, Hill Air Force Base, Proctor & Gamble, and Kennecott. The inventories are detailed in the technical support document. On-Road Mobile Source Emissions – like point sources, are legally bound to remain within the emission totals that are included in the SIP. This leads to some conservatism in the establishment of the projected emissions. Actual data is available to calculate emissions in the base-year, whereas projections are made using a travel demand model to estimate what emissions will likely be in the future. Transportation planning considers time horizons well beyond those used for air quality planning, and many assumptions are made when projecting transportation tendencies well into the future.

Again this makes legal sense, but tends to overstate a somewhat artificial “growth” in emissions from this sector.

In addition to the assumptions inherent in a travel demand model, there is another factor at play concerning mobile source emissions in the Salt Lake Valley. Tier 3 of the federal motor vehicle control program becomes effective in 2017, and it requires refiners of gasoline to limit the sulfur content of the fuel in order to achieve better overall performance in catalytic converters. The default value for sulfur in fuel beginning in 2017 is 10 ppm. The limit under Tier 2 had been 30 ppm. All of the refiners in the Salt Lake Valley are small (< 75,000 barrels per day) and have until 2020 to comply with the Tier 3 sulfur limit. Furthermore, corporate producers may average their compliance over the aggregation of their individual refineries. This means there is no legal guarantee that the Salt Lake Valley will see the Tier 3 fuel slated for 2017, even by 2020. For this reason, mobile source emissions in the analysis underlying the attainment demonstration were assumed to remain at 30 ppm. This is a conservative approach that feeds the air quality model more emissions in 2019, the attainment year.

UDAQ used the model to assess what affect some of this conservatism may be having on the determination of attainment.

No adjustments were made to the point source emissions, but for 2019, on-road mobile sources were adjusted by first assuming a 5% reduction to vehicle-miles-traveled (VMT) throughout the nonattainment area. Secondly, the fuel sulfur parameter was changed in MOVES from 30 ppm to 10 ppm.

Table 6.3 lists the reduction percentages in on-road mobile emissions using the modifications in VMT and fuel sulfur content.

On-road Mobile Emissions Reduction in the Salt Lake Nonattainment Area				
PM _{2.5}	NO _x	VOC	NH ₃	SO ₂
4%	12%	4%	5%	60%

Table 6.3: Percentage of 2019 on-road mobile inventory reduced in Salt Lake nonattainment area by lowering VMT by 5% and reducing fuel sulfur loading to 10 ppm. Reductions are with respect to on-road mobile sector only.

UDAQ re-ran the SMAT-CE v1.01 tool to develop another set of future design values, which could be compared to the existing set for 2019. **Table 6.4**, below, shows this comparison.

At both the Rose Park and Hawthorne monitors, these adjustments to the on-road mobile source inventory effectively decreased the predicted future design value by 0.2 µg/m³.

While notable, a decrease of this magnitude would not change the conclusion of the modeled attainment test. However, it does serve to illustrate that the result presented in the attainment test is likely conservative by at least this amount.

In addition, this exercise serves to underscore the insensitivity of the air quality model to what might be considered significant reductions in NO_x emissions throughout the Salt Lake City nonattainment area.

Monitor Name	Monitor ID	County	Baseline DV	Future DV (2019 baseline)	Future DV (5pVMT_10ppm)
Brigham City	490030003	Box Elder	31.9	29.4	28.4
Bountiful	490110004	Davis	29.3	29.3	29.2
Magna	490351001	Salt Lake	27.8	28	27.7
Hawthorne	490353006	Salt Lake	34.3	34.4	34.2
Rose Park	490353010	Salt Lake	36.7	36.5	36.3
Ogden #2	490570002	Weber	32.1	31.7	31.4

Table 6.4: Comparison of future design values using two different 2019 on-road mobile emissions inventories: baseline (Column 5), reduced VMT and fuel sulfur content (Column 6).

Note that the future design values presented in the column labeled (2019 baseline) do not exactly agree with those presented in section 6 as the modeled attainment test.

Additional refinements were made to the entire analysis between the time this exercise was completed and the final modeling runs. Nevertheless, one would not expect these refinements to change the 0.2 µg/m³ result of the exercise.

Controls Unaccounted for in the SIP:

Another example of conservatism in the analysis would be the omission of certain control measures that would be expected to improve air quality. Again, these controls were not

made part of the quantitative attainment demonstration because they are not suited to the assignment of SIP credit. Still, they are expected to mitigate PM_{2.5} concentrations.

Examples include:

VW Settlement Monies

Utah is a beneficiary of over \$35 million of the Volkswagen Diesel Emissions Environmental Mitigation Trust as a result of over 7,000 of the non-compliant VW cars operating in Utah. Utah has allocated \$25.7 million of this funding specifically for heavy-duty diesel vehicle replacements. The goal for the settlement money is to fully mitigate the excess lifetime NO_x from the non-compliant vehicles that operated in Utah. PM_{2.5} and VOC reductions will occur as well by removing old diesel vehicles from operation. It is estimated that the non-compliant cars in Utah emitted between 351-1,556 tons of excess NO_x. Depending on VW project applications and selection, Utah has the opportunity to reduce between 351-1,556 tons of NO_x, between 26-115 tons of PM_{2.5}, and between 35-156 tons of VOCs. Utah expects to accomplish these reductions in calendar years 2019-2024. The projects will be focused in Utah's nonattainment areas, with greater weight applied to areas of the state that bear a disproportionate amount of the air pollution burden.

Utah has an additional \$1.4 million in funding for projects such as lawnmower and snowblower exchanges, where gas-powered equipment is exchanged for electric equipment at a reduced cost.

Targeted Airshed Grant Money

The EPA has awarded the State over \$9.5 million to reduce pollution from woodstoves. The UDAQ will use the funding to offer Utah residents generous financial incentives to convert their woodstoves and fire places to cleaner sources of heat. Changing-out an old uncertified woodstove for an EPA-certified stove can reduce the amount of PM_{2.5} by as much as 60%. Converting a wood stove to a natural gas stove is even more beneficial, reducing PM_{2.5} by 99.9%.

Estimates show that the five year program will result in: 1) the destruction or recycling of 503 wood-stoves/inserts, 2) conversion of 496 wood-burning units to gas stoves, and 3) replacement of 1,006 uncertified wood stoves/inserts by EPA-certified wood-burning appliances. On a yearly basis, the change-out program would result in the destruction/recycling of 101 units, conversion of 99 wood-burning units to gas-fueled devices as well as the replacement of 201 uncertified wood-burning units by EPA-certified ones.

Implementation of the program is expected to result in the reduction of nearly 72% (or 18 tons) of PM_{2.5} and 87% (or 36 tons) of VOCs emissions from wood-smoke over the duration of the program. This is equivalent to a reduction of about 3.6 and 7.3 tons/year of PM_{2.5} and VOCs from wood-smoke, respectively.

Diesel Emission Testing

Currently there are three counties within the Salt Lake City Nonattainment Area (Davis, Salt Lake, and Weber) that have implemented a diesel emission inspection program. Each of the three programs is administered by its local health department, which may manage its program somewhat differently than the others. Although each is an independent program, they all share the same purpose of improving air quality through the detection and repair of excessively emitting vehicles.

1 In Davis County, all light, medium and heavy duty diesel powered vehicles are required
2 to undergo an emission test. The program consists of an On-Board Diagnostic (OBD) and
3 visual tampering inspection for model year 1996 and newer light duty (under 8,500 lbs
4 Gross Vehicle Weight Rating (GVWR)) diesel vehicles and model year 2008 and newer
5 medium duty (between 8,501 and 14, 000 lbs GVWR) diesel vehicles. Davis also tests
6 model year 1968 to 2007 medium duty diesel vehicles using an opacity inspection test
7 using a dynamometer, and finally, 1968 and newer Heavy Duty vehicle (over 14, 001 lbs
8 GVWR) are tested using Society of Automotive Engineers (SAE) J1667 or snap
9 acceleration procedure. Salt Lake County's diesel program consists of an OBD and
10 visual tampering inspection for 1998 and newer light and medium duty diesel powered
11 vehicle 14, 000 lbs GVWR and less. Salt Lake County also tests 1968 and newer Heavy-
12 Duty diesel vehicles over 14, 001 lbs GVWR using the SAE J1667 Snap Acceleration
13 Smoke Test Procedure. Weber County's program consists of an OBD inspection for
14 2008 and newer vehicles light-and medium duty vehicles (under 14001 lbs GVWR).
15 Weber County also conducts a visual tampering inspection for model year 1998 through
16 2007 diesel vehicles.

17 In any of the three counties, the frequency of inspection depends on the age of the
18 vehicle. Vehicles less than two years old, as of January 1 on any given year, are exempt
19 from an emissions inspection. Vehicles that are two years old but less than six are
20 inspected every other year, as per Utah Code 41-6a-1642(6). All vehicles six years old
21 and older are inspected annually.

22 Davis County reported a total of 9,096 diesel inspections completed during 2017. In
23 aggregate, 816 of these vehicles failed the particular inspection, which amounts to a 9%
24 fail rate. Of the total inspections performed, 3,346 were OBD inspections (12.8% fail
25 rate), 1,556 were snap-idle inspections (4.2% fail rate), and 4,194 were opacity
26 inspections (7.6% fail rate).

27 Weber County inspected 10,727 diesel vehicles in 2017. OBD inspections resulted in a
28 19 % failure rate (1999 vehicles), and visual tampering inspections produced a 7.5%
29 failure rate (801 vehicles).

30 Salt Lake County inspected a total of 42,002 diesel vehicles in 2017; 26,956 OBD
31 inspections with a 4.8% fail rate (1,295 vehicles), and 14,735 snap acceleration
32 inspections with a 2.8% fail rate (419 vehicles failed).

33 6.3 Conclusion: Air Quality as of the Attainment Date

34 This demonstration began with a modeled analysis that predicted PM_{2.5} concentrations in
35 2019, the attainment year, beneath the NAAQS at all stations but one, the Rose Park
36 station. Even at Rose Park, the prediction was very close (35.9 µg/m³). Additional
37 analysis was presented to supplement the modeled demonstration, including: an alternate
38 conclusion that did show a concentration beneath the NAAQS in 2019, trends in ambient
39 concentrations of PM_{2.5}, NO₂, and SO₂, trend in emissions of PM_{2.5} and its precursors,
40 some examples of how the modeled analysis might be considered conservative in its
41 assessment of emissions improvement, and perhaps most importantly, some examination
42 of what might be the shortcomings of the model as presently configured.
43 To this final point, one might consider the following when deciding how much the model
44 may be relied upon.

1 Despite a significant projected decrease in NO_x and VOC emissions between 2016 and
2 2019, the modeled PM_{2.5} results only show a slight decrease in predicted nitrate (NO₃).
3 The model simulates an ammonia-limited and oxidant-limited regime in the Salt Lake
4 Valley. However, observations from the recent 2017 UWFPS report suggest that the Salt
5 Lake Valley airshed is actually close to the equivalence point between NH₃ limited and
6 NO_x limited regimes during a wintertime inversion. This implies that if the model more
7 accurately represented the wintertime inversion episode, then one would certainly see a
8 bigger PM_{2.5} decrease relative to the sizable reduction in NO_x and VOC emissions
9 projected for 2019.

10 To improve modeled NO₃ (and hence, PM_{2.5}) performance, ammonia was artificially
11 injected into the emissions inventory. While this adjustment improved NO₃ performance,
12 it is associated with multiple uncertainties. As applied, the model assumes a uniform
13 temporal distribution and a coarse spatial variation in artificial ammonia emissions across
14 the Salt Lake Valley. Even with the additional ammonia, the model was still ammonia-
15 limited during the extent of the episode.

16 The model may also be too sensitive to oxidants levels. Carbonyls and ClNO₂, which are
17 sources of oxidants that promote PM_{2.5} and O₃ production, as shown by recent aircraft
18 measurements in the Salt Lake Valley, are underestimated in the model. Carbonyls,
19 particularly formaldehyde, are misrepresented in the model and the chemical pathway
20 responsible for ClNO₂ formation is not emulated at all.

21 These uncertainties in the model with regard to both the characterization of the regional
22 chemistry to the inventorying of certain constituents, ammonia in particular, may lead
23 one to give more weight to some of the empirical evidence. Past trends in emissions
24 reductions, particularly reductions in NO_x and SO₂, compare favorably with
25 commensurate trends in monitored PM_{2.5}. Against a more-or-less constant background of
26 direct PM_{2.5} emissions, these trends suggest that the area has experienced large
27 improvements in the magnitude of PM_{2.5} exceedances incurred during wintertime
28 episodes of cold pool meteorology. These episodes are dominated by secondary PM_{2.5}.
29 All indications are that PM_{2.5} precursor emissions, particularly NO_x and VOC, are
30 expected to decline markedly over the next 5 years. Based on past experience, there is no
31 reason to think that this would not continue to provide an improvement in ambient PM_{2.5}.
32 It is worth noting again that the model would in fact show attainment at all monitor
33 locations in 2019 if the data for August 20, 2015 is documented as being affected by an
34 exceptional event.

35 Finally, it should be noted that, based on historic monitoring trends and current
36 monitoring values, it is highly likely that the nonattainment area will attain the standard
37 and qualify for a clean data determination as soon as the 2018 monitored data can be
38 certified.

39 In summary, UDAQ is persuaded by these additional analyses and pieces of information,
40 and after considering the entire weight of evidence, conclude that it is in fact likely that
41 the Salt Lake City, UT PM_{2.5} nonattainment area will attain the 2006 24-hour PM_{2.5}
42 health standard by the attainment date in 2019.

Chapter 7 – TRANSPORTATION CONFORMITY

7.1 Introduction

The federal Clean Air Act (CAA) requires that transportation plans and programs within the Salt Lake City, Utah PM_{2.5} nonattainment area conform to the air quality plans in the region prior to being approved by the Wasatch Front Regional Council (WFRC) Metropolitan Planning Organization. Demonstration of transportation conformity is a condition to receive federal funding for transportation activities that are consistent with air quality goals established in the Utah State Implementation Plan (SIP). Transportation conformity requirements are intended to ensure that transportation activities do not interfere with air quality progress. Conformity applies to on-road mobile source emissions from regional transportation plans (RTPs), transportation improvement programs (TIPs), and projects funded or approved by the Federal Highway Administration (FHWA) or the Federal Transit Administration (FTA) in areas that do not meet or previously have not met the National Ambient Air Quality Standards (NAAQS) for ozone, carbon monoxide, particulate matter less than 10 micrometers in diameter (PM₁₀), or particulate matter 2.5 micrometers in diameter or less (PM_{2.5}), or nitrogen dioxide.

The Fixing America's Surface Transportation Act or "FAST Act" and section 176(c)(2)(A) of the CAA require that all regionally significant highway and transit projects in air quality nonattainment areas be derived from a "conforming" transportation plan. Section 176(c) of the CAA requires that transportation plans, programs, and projects conform to applicable air quality plans before being approved by an MPO. Conformity to an implementation plan means that proposed activities must not (1) cause or contribute to any new violation of any standard in any area, (2) increase the frequency or severity of any existing violation of any standard in any area, or (3) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area.

The plans and programs produced by the transportation planning process of the WFRC are required to conform to the on-road mobile source emissions budgets established in the SIP, or absent an approved or adequate budget, required to meet the interim conformity test. Approval of conformity is determined by the FHWA and FTA.

7.2 Consultation

The Interagency Consultation Team (ICT) is an air quality workgroup in Utah that makes technical and policy recommendations regarding transportation conformity issues related to the SIP development and transportation planning process. Section XII of the Utah SIP established the ICT workgroup and defines the roles and responsibilities of the participating agencies. Members of the ICT workgroup collaborated on a regular basis during the development of the PM_{2.5} SIP. They also meet on a regular basis regarding transportation conformity and air quality issues. The ICT workgroup is comprised of

1 management and technical staff members from the affected agencies associated directly
2 with transportation conformity.

3 4 **ICT Workgroup Agencies**

- 5 • Utah Division of Air Quality (UDAQ)
- 6 • Metropolitan Planning Organizations MPOs
 - 7 ▪ Cache MPO
 - 8 ▪ Mountainland Association of Governments
 - 9 ▪ Wasatch Front Regional Council
- 10 • Utah Department of Transportation (UDOT)
- 11 • Utah Local Public Transit Agencies
- 12 • Federal Highway Administration (FHWA)
- 13 • Federal Transit Administration (FTA)
- 14 • U.S. Environmental Protection Agency (EPA)

15 The regional emissions analysis is the primary component of transportation conformity
16 and is administered by the lead transportation agency located in the EPA designated air
17 quality nonattainment area. The responsible transportation planning organization for the
18 Salt Lake City, UT nonattainment area is the Wasatch Front Regional Council (WFRC).
19 During the SIP development process the WFRC coordinated with the ICT workgroup and
20 developed PM_{2.5} SIP motor vehicle emissions inventories using the latest planning
21 assumptions and tools for traffic analysis and the EPA-approved Motor Vehicle Emission
22 Simulator (MOVES2014a) emissions model. The WFRC and the ICT worked
23 cooperatively to develop local MOVES2014a modeling data inputs using EPA
24 recommended methods where applicable.

25 **7.3 Transportation Conformity PM_{2.5} Components**

26 The transportation conformity requirements found in 40 CFR 93.102 requires that the
27 PM_{2.5} SIP include motor vehicle emissions budgets for PM_{2.5} precursor emissions of
28 ~~[Nitrogen-]~~Oxides [of Nitrogen](#) (NO_x) and Volatile Organic Compounds (VOC), and
29 direct PM_{2.5} (primary exhaust PM_{2.5} + brake and tire wear) emissions. VOC emissions
30 precursor budgets are required because UDAQ has identified VOCs as a PM_{2.5} precursor
31 that significantly impact PM_{2.5} concentrations.

32 The EPA conformity rule presumes that PM_{2.5} re-entrained road dust does not need to be
33 included in the interim conformity test unless either the State or EPA decides that re-
34 entrained road dust emissions are a significant contributor to the PM_{2.5} nonattainment
35 problem. The UDAQ conducted a re-entrained road dust study that concluded that PM_{2.5}

1 re-entrained road dust emissions are negligible in the Salt Lake City, Utah PM_{2.5}
2 nonattainment area, and thus meet the criteria of 40 CFR 93.102(b)(3). EPA Region 8
3 reviewed the study and concurred with the UDAQ's findings. The re-entrained road dust
4 insignificant finding is located in the On-Road Mobile Sources PM_{2.5} Episodic Inventory
5 TSD.

6 7.4 Interim PM_{2.5} Conformity Test

7 The EPA interim conformity test, for the purposes of this plan revision, will require that
8 PM_{2.5} precursor emissions of NO_x and VOC, and direct PM_{2.5} (primary exhaust PM_{2.5} +
9 brake and tire wear) emissions from RTPs, TIPs, and projects funded or approved by the
10 FHWA or the FTA not exceed 2008 levels.

11 The Interim conformity test requirements apply until EPA has declared the motor vehicle
12 emissions budgets adequate for transportation conformity purposes or until EPA approves
13 the budget in the Federal Register.
14

7.5 Transportation Conformity PM_{2.5} Budgets

~~[The Wasatch Front Regional Council requested motor vehicle emissions budgets (MVEBs) for the Salt Lake City, PM_{2.5} nonattainment area.]~~ In this SIP, the State is establishing transportation conformity MVEBs for the Salt Lake City, PM_{2.5} nonattainment area. The MVEBs are established for tons per average winter weekday (tpww) for PM_{2.5} precursors NO_x and VOC, and for direct PM_{2.5} (primary exhaust PM_{2.5} + brake and tire wear). [WFRC applied an increased growth rate of 5% to the Vehicle Miles of Travel. This growth rate adjustment was applied to allow for unanticipated fluctuations in future VMT. VMT growth rate assumptions may be found in the Technical Support Document \(TSD\) for On-Road Mobile Sources \(at Chapt. 3.e, see: iii. MOVES Modeling Procedure: 3. MOVES2014 Local Model Inputs\).](#)

Table 7.1, Emissions Budgets for Transportation Conformity Purposes (EPA MOVES2014a).

	Direct PM _{2.5} (tpww)	NO _x (tpww)	VOC (tpww)
2017	2.68	59.92	32.67
2019	2.27	50.07	28.85
2020	2.11	45.84	26.88

Note: TPWW: Tons Per Average Winter Weekday. Direct PM_{2.5} is Primary Exhaust PM_{2.5} total + brake and tire wear. VOC emissions do not include refueling spillage and displacement vapor loss. Budgets are rounded to the nearest hundredth ton. [Derivation of the MVEBs may be found in the Technical Support Document for On-Road Mobile Sources \(at Chapt. 3.e, see: iv. Quantifiable Nonattainment Modeling Results and Motor Vehicle Emissions Budget Derivation\).](#)

It is important to note that the MVEBs presented in Table 7.1 are somewhat different from the Summary Emissions Inventory (EI) presented in **Table 4.1**. Overall the emissions established as MVEBs are calculated using MOVES to reflect an average winter weekday. The totals presented in the Summary EI, however, represent an average-episode-day. The episode used to make this average (December 31, 2010 through January 10) includes seven such winter weekdays, but also includes two weekends. Emissions produced on weekdays are significantly larger than those produced on both Saturdays and Sundays. Therefore, the weighted average of daily emissions calculated for an episode-day will be less than that of a weekday. There are also some conventions to be considered in the establishment of MVEBs. In particular: PM_{2.5} in the Summary EI totals includes direct exhaust, tire & brake wear, and fugitive dust. For the MVEBs PM_{2.5} includes direct exhaust, tire & brake but no fugitive dust. VOC emissions in the Summary EI totals include refueling spillage and displacement vapor loss. These emissions were included in the Summary EI as belonging to the On-Road Mobile Source. MVEBs for VOC do not include these emissions because, in this context, they are regarded as an Area Source.

1
2

3 7.6 Trading Ratios

4 Per section 93.124 of the conformity regulations, for transportation conformity analyses
5 using these budgets in analysis years beyond 2020, a trading mechanism is established to
6 allow future increases in on-road direct PM_{2.5} emissions to be offset by future decreases
7 in plan precursor emissions from on-road mobile sources at appropriate ratios established
8 by the air quality model. Future increases in on-road direct PM_{2.5} emissions may be
9 offset with future decreases in NO_x emissions from on-road mobile sources at a NO_x to
10 PM_{2.5} ratio of 12.67 to 1 and/or future decreases in VOC emissions from on-road mobile
11 sources at a VOC to PM_{2.5} ratio of 31.96 to 1. This trading mechanism will only be used
12 if needed for conformity analyses for years after 2020. To ensure that the trading
13 mechanism does not impact the ability to meet the NO_x or VOC budgets, the NO_x
14 emission reductions available to supplement the direct PM_{2.5} budget shall only be those
15 remaining after the 2020 NO_x budget has been met, and the VOC emissions reductions
16 available to supplement the direct PM_{2.5} budget shall only be those remaining after the
17 2020 VOC budget has been met. Clear documentation of the calculations used in the
18 trading should be included in the conformity analysis. [The assumptions used to create the](#)
19 [trading ratios may be found in the following document, "Trading Ratios for Conformity](#)
20 [Salt Lake Serious PM_{2.5}", included in Chapter 8 Misc. of the TSD.](#)
21
22

Chapter 8 – QUANTITATIVE MILESTONES DEMONSTRATING REASONABLE FURTHER PROGRESS

8.1 Introduction

Clean Air Act Section 172(c)(2) requires that plans for nonattainment areas “shall require reasonable further progress (RFP).” This general requirement is interpreted for PM_{2.5} areas in EPAs’ Implementation Rule for Fine Particulate Matter (81 FR, 58010). The definition of RFP is given in 40 CFR 51.1000. It means “such annual incremental reductions in emissions of direct PM_{2.5} and PM_{2.5} plan precursors as are required for the purpose of ensuring attainment of the applicable PM_{2.5} NAAQS in a nonattainment area by the applicable attainment date.”

In general terms, the goal of these RFP requirements is for areas to achieve continual progress toward attainment, rather than perhaps deferring implementation of all measures until the attainment deadline.

The pollutants to be addressed in the RFP plan are those pollutants that are identified for purposes of control measures in the attainment plan: PM_{2.5}, SO₂, NO_x, VOC, and ammonia.

8.2 Serious Area Planning Requirements

The planning requirements RFP and Quantitative Milestones within PM_{2.5} nonattainment areas are given in 40 CFR 51 paragraphs 1012 and 1013. In summary:

The RFP plan must demonstrate annual incremental reductions in emissions (direct PM_{2.5} and precursors) to ensure attainment by the attainment date. It shall include:

- A schedule describing the implementation of control measures during each year of the plan.
- RFP projected emissions for each applicable milestone year, based on the anticipated implementation schedule for control measures.
- An analysis that demonstrates that by the end of each milestone year emission levels will reflect progress that is either generally linear or stepwise.
- Also, there must be a tracking mechanism for the progress that is expected.
- Finally, for purposes of establishing motor vehicle emissions budgets... (as required in 40 CFR part 93) for a PM_{2.5} nonattainment area, the state shall include in its RFP submission an inventory of on-road mobile source emissions in the nonattainment area for each milestone year.

For areas like the SLC, UT area that were designated nonattainment for the 2006 PM_{2.5} NAAQS prior to January 15, 2015, the first milestone is December 31, 2017. Additional milestones will occur every three years thereafter, up until and including the first such milestone after the attainment date. The attainment date for this plan is December 31, 2019. Therefore, the second and final milestone will come due at December 31, 2020.

8.3 RFP for the Salt Lake City, UT Nonattainment Area

The attainment demonstration for the SLC, UT PM_{2.5} nonattainment area shows that the 2006, 24-hr NAAQS can be achieved by the attainment date of December 31, 2019. Essentially, this may also be considered to demonstrate that the area is achieving RFP. The emissions reductions associated with the application of BACM and BACT were factored into an inventory for 2019 that was assessed using air quality modeling as well as other information and analyses. The entire analysis demonstrates that these reductions in emissions are likely sufficient to demonstrate attainment of the applicable standard by the applicable attainment date. The starting point for evaluating RFP should be the baseline year used in the modeling analysis. This is a year (2016) selected to coincide with the period used to establish the monitored design value for the modeling analysis; a period in which the area was violating the applicable NAAQS. Thus, the magnitude of emissions reductions should be evaluated over a period spanning from 2016 through 2019. Quantitatively, the following assessment of emissions and incremental emissions reductions in **Table 8.1** will show that RFP is met using the criteria discussed above:

Reasonable Further Progress									
Salt Lake City, UT PM2.5 Nonattainment Area									
*Emissions by Year			Base Yr.	Projection Years with Growth & Controls					
			2016	2017	2019	2020	**RFP		
PM2.5			15.4	15.8	16.1	16.0	0.2		
NOx			103.6	100.2	94.9	87.9	-2.9		
SO2			5.6	5.6	4.9	4.9	-0.2		
VOC			91.7	91.5	86.8	83.5	-1.6		
NH3			16.0	16.0	16.0	15.9	0.0		
PM2.5 Precursors			216.9	213.2	202.6	192.2	-4.8		
Total			232.3	229.0	218.7	208.2	-4.5		
*Emissions are reported in tons per average-episode-day									
**Emission change per year, (ton/day) averaged from Base Year (2016) through Attainment Year (2019)									

Table 8.1, Reasonable Further Progress in the SLC, UT Nonattainment Area

Emissions in **Table 8.1** have been aggregated to include all four source categories. RFP projected emissions, however, are defined to look at each source category individually.

That information appears already in **Table 4.1**, but is included here also as **Table 8.2** for the ease of discussion.

Emissions in both tables show not just the effect of BACM and BACT, but also growth in population and vehicle miles traveled. Even with the inclusion of growth, the trends are still downward.

Emissions [tons/day]	Sector	PM2.5	NOx	VOC	NH3	SO2
2016 Base Year	Area Sources	6.13	13.63	45.96	14.22	0.17
	Mobile Sources	4.98	55.38	31.84	1.29	0.41
	NonRoad Sources	1.01	16.41	8.70	0.02	0.32
	Point Sources	3.26	18.18	5.25	0.44	4.70
	Total	15.38	103.61	91.74	15.97	5.60
2017 Milestone Year	Area Sources	6.19	13.57	46.02	14.21	0.22
	Mobile Sources	5.02	52.53	30.87	1.30	0.43
	NonRoad Sources	0.96	15.77	8.47	0.02	0.33
	Point Sources	3.58	18.32	6.13	0.44	4.61
	Total	15.75	100.18	91.48	15.97	5.59
2019 Attainment Year	Area Sources	6.23	11.84	44.34	14.21	0.22
	Mobile Sources	4.78	44.02	27.26	1.25	0.43
	NonRoad Sources	0.88	15.18	9.01	0.02	0.35
	Point Sources	4.25	23.86	6.21	0.48	3.90
	Total	16.13	94.90	86.82	15.96	4.89
2020 Milestone Year	Area Sources	6.24	9.54	43.73	14.20	0.20
	Mobile Sources	4.68	40.38	25.42	1.23	0.42
	NonRoad Sources	0.82	14.08	8.10	0.02	0.36
	Point Sources	4.26	23.86	6.22	0.49	3.90
	Total	16.00	87.86	83.47	15.94	4.88

* Salt Lake nonattainment area only

Table 8.2, RFP Projected Emissions in the SLC, UT Nonattainment Area

From **Table 8.2** it can be seen that the overall decrease in total NO_x and VOC emissions is, as expected, dominated by improvements in the On-Road Mobile Source category. Yet, there are significant improvements in the Area Source category as well. Point Sources are responsible for the increase in PM_{2.5} emissions, but also account for the decline in SO₂. Ammonia emissions are essentially flat, but most of the reported ammonia is not attributed to any of the source categories. Rather, it has been artificially introduced into the analysis to improve model performance.

Table 8.2 also shows the emissions from on-road mobile sources in the milestone years. As noted in **section 7.5**, these totals differ somewhat from the MVEBs.

Control Measures: The inventory for 2019 “with growth and controls” reflects the implementation of all the best available control measures and best available control technologies identified in this plan, as well as all pre-existing control measures. As such, this inventory takes into account all controls that “may reasonably be required by the Administrator.”

For a complete discussion of BACM and BACT, and the control measures factored into the modeled demonstration for 2019, see Chapter 5 of the Plan.

For purposes of Milestone tracking, it is worth distinguishing those controls relied upon by this SIP that have been required by the State of Utah. Since these control measures have been required specifically for the purpose of this SIP it will be incumbent on the

State to make sure they are implemented, and then to verify as much in any subsequent milestone reporting requirement. These controls differ from controls that are already on the books or controls that are implemented at the federal level. Specifically, such State-specific controls reside in the categories of area and stationary point sources. A listing of these State-specific control measures appears, for area and stationary point source categories, in Tables 8.3 and 8.4 respectively.

<u>EPA-Approved/Conditionally Approved Control Measures for UT Moderate PM_{2.5} SIPs</u>	<u>Implementation Schedule</u>	<u>Estimated Reductions in the SLC NAA*</u>
<u>R307-302 Solid Fuel Burning Devices</u> ¹ <u>EPA conditionally approved October 19, 2016 (81 FR 71988).</u>	<u>February 1, 2017</u>	<u>See Table 5-1 residential wood burning ban</u>
<u>R307-303 Commercial Cooking</u> ¹ <u>EPA approved February 25, 2016 (81 FR 9343).</u>	<u>December 15, 2015</u>	<u>See Table 5-1 commercial cooking</u>
<u>R307-304 Solvent Cleaning</u> ¹	<u>December 6, 2017</u>	<u>See Table 5-1 a subset of degreasing</u>
<u>R307-309 Nonattainment and Maintenance Areas for PM₁₀ and PM_{2.5}: Fugitive Emissions and Fugitive Dust</u> ¹ <u>EPA approved February 25, 2016 (81 FR 9343).</u>	<u>Salt Lake County, Utah County, and the City of Ogden – January 1, 2013.</u> <u>Remaining NAAs – April 1, 2013.</u> <u>Amended August 4, 2017</u>	<u>See Table 5-1 fugitive dust</u>
<u>R307-312 Aggregate Processing Operations for PM_{2.5} Nonattainment Areas.</u> <u>EPA approved October 19, 2016 (81 FR 71988).</u>	<u>February 4, 2016</u>	<u>See Table 5-1 aggregate operations</u>
<u>R307-335 Degreasing and Solvent Cleaning Operations</u> ¹ <u>EPA approved February 25, 2016 (81 FR 9343).</u>	<u>All sources within Salt Lake and Davis Counties R307-335-3 through R307-335-6 – January 1, 2013.</u> <u>All other sources defined in R307-335-2 – September 1, 2013.</u> <u>All sources within Box Elder, Cache, Utah, Weber, and Tooele Counties R307-335-7 – August 1, 2014</u> <u>Amended October 29, 2017 by removing sections 6 & 7 to for rule R307-304</u>	<u>See Table 5-1 a subset of degreasing</u>
<u>R307-342 Adhesives & Sealants</u> ¹ <u>EPA approved February 25, 2016 (81 FR 9343).</u>	<u>December 1, 2014</u>	<u>See Table 5-1 adhesive/sealants</u>
<u>R307-343 Emissions Standards for Wood Furniture Manufacturing Operations</u> ¹ <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – September 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2014.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 wood furniture manufacturing</u>

<u>EPA-Approved/Conditionally Approved Control Measures for UT Moderate PM_{2.5} SIPs</u>	<u>Implementation Schedule</u>	<u>Estimated Reductions in the SLC NAA*</u>
<u>R307-344 Paper, Film & Foil Coatings¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – February 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2014.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 paper/film/foil</u>
<u>R307-345 Fabric & Vinyl Coatings¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – February 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2011.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 fabric/vinyl</u>
<u>R307-346 Metal Furniture Surface Coatings²</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – February 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2014.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 metal furniture</u>
<u>R307-347 Large Appliance Surface Coatings²</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – February 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2014.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 appliance</u>
<u>R307-348 Magnet Wire Coatings²</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – February 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2014.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 magnet wire</u>
<u>R307-349 Flat Wood Panel Coatings¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – February 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2014.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 flat wood</u>
<u>R307-350 Miscellaneous Metal Parts and Products Coatings¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – September 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2014.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 misc. metal</u>

<u>EPA-Approved/Conditionally Approved Control Measures for UT Moderate PM_{2.5} SIPs</u>	<u>Implementation Schedule</u>	<u>Estimated Reductions in the SLC NAA*</u>
<u>R307-351 Graphic Arts¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>Sources in Salt Lake and Davis Counties – February 1, 2013.</u> <u>Sources in Box Elder, Cache, Tooele, Utah, and Weber Counties – January 1, 2014.</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 graphic art</u>
<u>R307-352 Metal Containers, Closure, and Coil Coatings²</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>January 1, 2014</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 coil/containers</u>
<u>R307-353 Plastic Parts Coatings¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>January 1, 2014</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 plastic</u>
<u>R307-354 Automotive Refinishing Coatings¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>January 1, 2014</u> <u>Amended December 6, 2017</u>	<u>See Table 5-1 autobody</u>
<u>R307-355 Control of Emissions from Aerospace Manufacture and Rework Facilities¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>January 1, 2014</u> <u>Amended March 8, 2018</u>	<u>See Table 5-1 aerospace</u>
<u>R307-356 Appliance Pilot Light¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>January 1, 2013</u>	<u>See Table 5-1 pilot light</u>
<u>R307-357 Consumer Products¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>May 8, 2014</u>	<u>See Table 5-1 consumer products</u>
<u>R307-361 Architectural Coatings¹</u> <u>EPA approved February 25, 2016 (81 FR 9343)</u>	<u>October 31, 2013</u>	<u>See Table 5-1 paint</u>

Table 8.3, RFP / Quantitative Milestone Tracking Table for Area Sources. *uncontrolled to controlled 2019 emissions. ¹ Potential 2020 quantitative milestone reporting metrics: control measure implementation schedule and confirmation that measures have been implemented. ² Potential 2020 quantitative milestone reporting metrics: control measure implementation schedule and review if any new sources located in the NAA.

Company	RACT Equipment Update(s)	BACT Requirement(s)	Implementation Schedule	Quantify Reduction (tons/yr)	Compliance Mechanism
ATK Launch Systems Inc.	Two (2) 25 MMBTU/hr Natural Gas Boilers	Ultra Low Nox Burners	31-Dec-24	NOx ~ 10.44 tons/yr	AO Issuance
Big West Oil Company	Hydrocarbon Flares	Limited routine flaring between Oct 1st and March 31st.	Date of SIP Approval	N/A	AO Issuance
	Carbon Canisters/Fire Pumps	Miscellaneous Carbon Canister and Fire Pump Changes	31-Dec-19	VOC ~ 15.4 tons/yr	AO Issuance
Chemical Lime Company	Lime Kiln	Selective Non-catalytic Reduction	Upon Source Start-up	N/A	AO Issuance
		New Baghouse	Upon Source Start-up	N/A	AO Issuance
Chevron Products Co.	Boilers/Compressor Drivers	Replacement of 4 Compressor Drivers	31-Dec-19	N/A	AO Issuance
	Tier 3 Fuels	Removal of Boilers 1, 2, & 4; Replacement with Boiler 7	31-Dec-19	N/A	AO Issuance
Compass Minerals	Boilers #1 & #2 - Required Nox Limitations PM2.5 Filterable and Condensable emission limits required for 14 emission points	Ultra low Nox burners/Upgrades to Baghouses	31-Dec-19	NOx ~ 10 tons/yr	AO Issuance
Hexel Corporation	Carbon Fiber Lines	Addition of Filter Boxes on Lines 13 & 14 De-NOx Water Direct Fired Thermal Oxidizer on Lines 13, 14, 15 & 16 Low-Nox Burners w/fuel gas re-circulation on Lines 3, 4, & 7	31-Dec-19 31-Dec-24 31-Dec-24	PM 2.5 ~ 20 tons/yr NOx ~ 75 tons/yr NOx ~ 25.5 tons/yr	AO Issuance AO Issuance AO Issuance
Hill Air Force Base	Painting and De-painting	VOC emission limitation for painting activities.	31-Dec-24	PM2.5 ~ 11.8 tons/yr	AO Issuance
	Boilers	Requirement that no boilers manufactured after January 1, 1989 over 30 MMBtu/hr be operated.		NOx ~ 434.38 tons/yr VOC ~ 8.53 tons/yr	
Holly Corporation	Wet Gas Scrubber & Boiler	Installation of Wet Gas Scrubber and Boiler Replacement	N/A	N/A	N/A
Kennecott Utah Copper					
Mine	Mine	Mileage limitation and Required lower emission rate for in-pit crusher	Date of SIP Approval	PM2.5 ~ 4.33 tons/yr	AO Issuance
Power Plant	Power Plant upgrades	Unit #4: Installation of SCR and Overfired Air; Unit #4: Lower ppm and lb/hr testing requirement.	1-Jan-19	NOx ~ 1,268.8 tons/yr (8760 hrs of operation) NOx ~ 302.43 tons/yr (2088 hrs of operation)	AO Issuance AO Issuance
Smelter & Refinery	Smelter & Refinery upgrades	Replacement of one (1) 82 MMBtu/hr Tankhouse Boiler	1-Dec-20	NOx ~ 35.04 tons/yr (8760 hrs of operation)	AO Issuance
Nucor Steel Mills	No Changes	No BACT Changes	N/A	N/A	N/A
Pacificorp Energy					
Gadsby Power Plant	No Changes	No BACT Changes	N/A	N/A	N/A
Proctor & Gamble	Utility Boilers	PM2.5 Filterable and Condensable Limits & Nox Limits Workload changes at facility	N/A	N/A	AO Issuance
Tesoro Refining	Refinery Operations	Installation of Wet Gas Scrubber	31-Oct-19	N/A	AO DAQE-103350075-18
University of Utah	Heating Plant	Replacement of Boiler #4. Installation of Boiler #9. Natural Gas limitations on Boilers #1, #3, & #4.	31-Dec-19 30-Sep-19	NOx ~ 44.29 tons/yr NOx ~ 4.27 tons/yr	AO Issuance AO Issuance
Utah Municipal Power Agency	Power Plant	No BACT required changes	N/A	N/A	N/A
Vulcraft	Steel Fabrication	No BACT required changes	N/A	N/A	N/A

Table 8.4, RFP / Quantitative Milestone Tracking Table for Point Sources

Schedule for the Implementation of BACM and BACT: RFP must be considered in light of the attainment date as well as the date by which all BACT and BACM must be implemented. Consideration is also given to the attainment demonstration which must make its assessment as of the attainment date. For the SLC-UT nonattainment area the attainment date is December 31, 2019. 40 CFR 51.1011 establishes that control measures must be implemented no later than the beginning of the year containing the applicable attainment date. Thus, for purposes of RFP and SIP credit, the deadline for implementation of all BACT and BACM is January 1, 2019. Any control measures implemented beyond such date are instead regarded as additional feasible measures. Implementation dates for the State-specific control measures have been included in Tables 8.3 and 8.4.

The improving trends in emissions are evident from **Table 8.1**, but it is important to look more closely and determine whether the downward trends are either generally linear in character or whether they reveal a more stepwise shape. **Figure 8.1** is included to make this assessment.

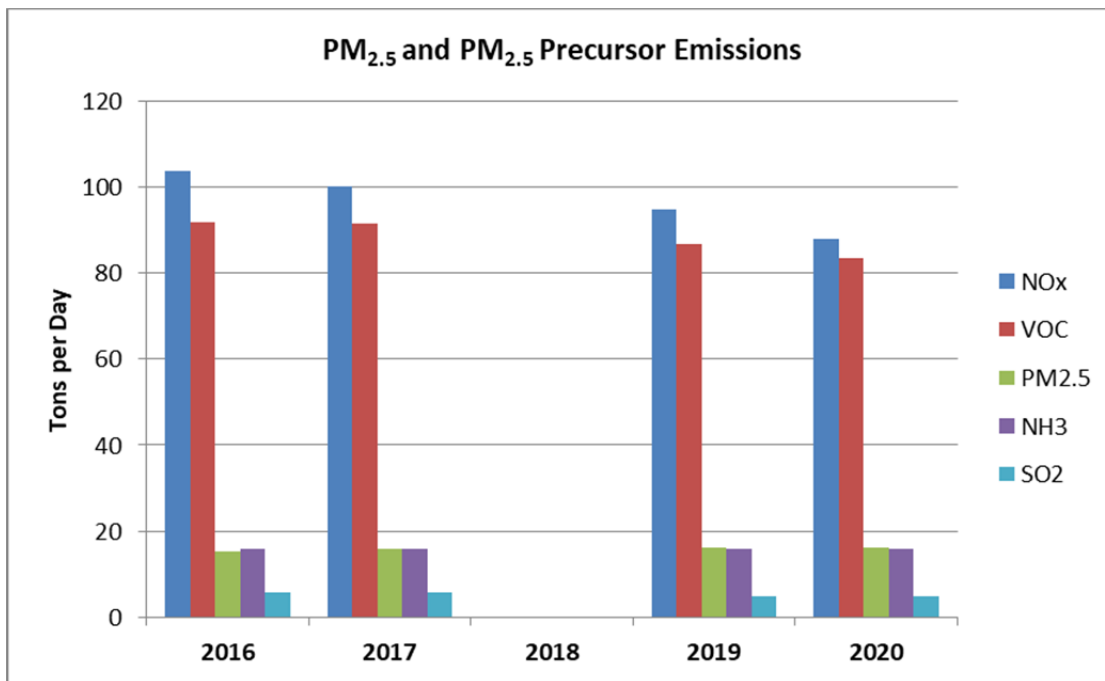


Figure 8.1 Emissions totals for PM_{2.5} and PM_{2.5} precursors in the Base Year (2016), Attainment Year (2019), and Milestone Years (2017 and 2020)

From the figure, it may be seen that the trends in SO₂ and VOC show a stepwise decline between 2017 and 2019. This is supported by the implementation date (Dec. 31, 2018) for BACM & BACT. In particular, Area Source BACM rules were projected to become fully effective by 2019, and most of these rules targeted VOC emissions. The decline in SO₂ emissions is explained by the installation of a wet-gas scrubber at ~~[one of the refineries]~~ Tesoro Refining & Marketing Co. LLC in 2018.

1 The trend in NO_x is more linear, remaining steadily downward with the continued
2 implementation of Tier 2 of the federal motor vehicle control program. The introduction
3 of Tier 3 in 2017 is likely accelerating the downward trend from 2019 to 2020.
4 The trend of primary PM_{2.5} emissions is seen to be relatively flat. This is consistent with
5 the trend seen since all the way back to about 2000 (see **Figure 6.21**).
6 It is also interesting to note in light of the improvement shown in the ambient monitoring
7 data for PM_{2.5} (**Figures 6.15 and 6.16**). As noted in the Weight of Evidence discussion
8 (**section 6.2**), the actual improvement in monitored PM_{2.5} concentrations, both peak and
9 annual values, is likely due to reductions in PM_{2.5} precursor emissions; effectively
10 shaving the peaks off of the wintertime exceedances composed mainly of secondary
11 nitrate.

12 8.4 Milestones for the SLC, UT Nonattainment Area

13 The PM Implementation Rule requires quantitative milestones, which demonstrate
14 reasonable further progress, to be achieved every three years.
15 Not later than 90 days after the milestone comes due, Utah must submit a milestone
16 report that certifies that the SIP control strategy is being implemented. The report must
17 also include a discussion of whether the area will attain the NAAQS by the applicable
18 date.
19 In order that it may make such certification, Utah will need to track the implementation
20 of BACM and BACT. This will be accomplished for the point sources by the issuance of
21 Approval Orders authorizing construction of any required modifications as well as on-site
22 inspections to verify that any operating practices have been implemented. Utah will also
23 work with the EPA to ensure that any rulemaking actions taken to implement BACM at
24 the many area sources in the nonattainment area have been approved into the Utah SIP.
25 If it fails to submit the quantitative milestone demonstration, or if EPA determines that
26 the milestone was not met, The State is required to submit a SIP revision ensuring that
27 the next milestone will be met or alternately that the NAAQS will be attained.
28 UDAQ herein commits to prepare and submit a milestone report no later than 90 days
29 from the attainment date.
30

Chapter 9 – CONTINGENCY MEASURES

9.1 Background

The Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule details under the contingency measure requirements (40 CFR 51.1014) that the state must include contingency measures that shall take effect with minimal further action by the State or the EPA following a determination by the EPA Administrator that the area has failed to:

- 1) meet the RFP requirements set forth in this SIP,
- 2) meet any quantitative milestone detailed in this SIP,
- 3) submit a quantitative milestone report for this SIP; or
- 4) attain the standard by the attainment date set forth in this SIP.

The PM Implementation Rule states that the contingency measure(s) shall include control measures that are not already included in the SIP. Each contingency measure shall specify the timeframe that the requirements will become effective following determination by the EPA Administrator that the area has failed to meet one of the requirements listed above in 1-4. The SIP must also contain a description of the specific trigger mechanisms for the contingency measure(s).

The rule does not include any specific level of emission reductions that must be adopted to meet the contingency measures requirement under section 172(c)(9).

9.2 Contingency Measures and Implementation Schedules for the Nonattainment Area

Nothing precludes a State from implementing a contingency measures before it is actually triggered, but the credit for a contingency measure may not be used in either the attainment or reasonable further progress demonstrations.

The following measure is already fully functioning, and it is not currently being used as a control strategy in this SIP:

Heavy-duty diesel engine emissions reduction programs: Through the EPA's Clean Diesel Program funded by the Diesel Emissions Reduction Act (DERA), Utah currently has an estimated \$5 million in grants to reduce diesel emissions by replacing or retrofitting old diesel engines that have outdated emissions standards with new, cleaner vehicles or emissions reduction retrofit equipment.

For calendar years 2015-2017, the average annual emissions reductions from Clean Diesel projects within the nonattainment area are as follows:

	NO _x	PM _{2.5}	VOC
2015	49 tons	3.4 tons	4.2 tons

2016	49 tons	3.4 tons	4.2 tons
2017	49 tons	3.4 tons	4.2 tons

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Funding amounts have increased in recent years and the projected average annual emissions reduction based on funding sources already in place for the NAA for calendar years 2018-2020 are:

	NO_x	PM_{2.5}	VOC
2018	182 tons	14 tons	20 tons
2019	182 tons	14 tons	20 tons

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6
7

The grant funding amounts are expected to stay similar or increase, resulting in the following minimum annual emissions reductions in the future:

	NO_x	PM_{2.5}	VOC
2020	182 tons	14 tons	20 tons
2021	182 tons	14 tons	20 tons
2022	182 tons	14 tons	20 tons
2023	182 tons	14 tons	20 tons

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Since Clean Diesel projects are continuously being carried out in the State, it is not necessary for a trigger mechanism or implementation schedule. Therefore, this contingency measure will already be fully functioning and implemented in the case that it becomes necessary for credit.

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ATTACHMENT B

Part A Comments and Responses

Compass Minerals

Comment Summary A-1: Compass Minerals provided discussion regarding the BACT analysis for NO_x control for the 108.11 MMBtu/hr Boilers #1 and #2. This discussion was in regards to a 20-year equipment life which was used in the BACT analysis versus a 10-year equipment life for process heater burners.

UDAQ Response to A-1: This Comment has been discussed with Compass Minerals and determined to be a more appropriate comment for the Part H Section which was out for comment November 1, 2018 thru November 30, 2018. The DAQ will address this comment in the Part H Comment Response for the above stated comment period.

Comment Summary A-2: Compass Minerals concurred with the Salt Lake Area BACT analysis for fugitive dust (i.e., R307-309) stating, “UDAQ’s BACM clearly meets federal requirements as there are no other potential requirements that would lead to meaningful further emission reductions.” Compass minerals proceeded to provide supporting rational based on EPA guidance, 57 Federal Register 13498, 13544 April 16, 1992 and US EPA Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures (September 1992).

UDAQ Response to A-2: UDAQ agrees with the commenter regarding the fugitive dust rule R307-309.

Environmental Protection Agency, Region 8

Comment Summary A-3: [C-1: EPA Region 8 Comments Regarding the Utah Petroleum Associations’ Comments [submitted by EPA Region 8, **Enclosure 1**] **UDAQ Response to A-3 presented throughout: Additional discussion surrounding responses to the comments below may be found in the Response to Comment A-16 and in the “Draft UDAQ Major Stationary Source Precursor Demonstration for the Salt Lake City 24-hour PM_{2.5} Serious non-attainment Area” attached to these comments.**

Comment 1: Source impacts from nitrogen oxide (NO_x) precursor emissions should be evaluated using CAMx Particulate Source Apportionment Technology (PSAT), due to the potential for non-linear model response to changes in NO_x precursor emissions. In NO_x saturated photochemical regimes, model simulations of reductions in NO_x emissions from individual sources can predict increases in ammonium nitrate, even though the cumulative effect of NO_x reductions from all sources combined would show reductions in ammonium nitrate. We note that the Utah Petroleum Association (UPA)/Ramboll sensitivity simulations show negative mass contributions of NO_x to PM_{2.5} which is an indicator of the effect of the non-linear response. The CAMx PSAT addresses this concern by tracking the mass contributions from individual sources instead of the sensitivity to an individual source. Other precursors can also be tracked using

1 PSAT, but in this particular case, NO_x as a precursor to PM_{2.5} is most likely to be
2 sensitive to the particular modeling technique.

3
4 **Response to Comment 1:** In a region that is rich in NO_x, a process called ozone (O₃)
5 scavenging can occur where particulate nitrate (PNO₃) formation is suppressed. If NO_x
6 was reduced in such a NO_x-saturated region, more PNO₃ could result. This NO_x
7 “disbenefit” mechanism is emulated in the CAM_x model. Therefore, a sensitivity based
8 analysis of NO_x contribution to PM_{2.5} could give counterintuitive results where reducing
9 NO_x actually produces more PNO₃. The source apportionment approach, PSAT,
10 quantifies how much PNO₃ is ultimately the result of specific sources. However, PSAT
11 can’t address how PNO₃ responds to changes in source-specific NO_x emissions. UDAQ
12 did conduct a PSAT model run looking at PNO₃, sulfate, and ammonium attribution from
13 Salt Lake nonattainment area point sources.

14
15 **Comment 2:** The modeled PM_{2.5} impacts are best evaluated and documented for
16 individual PM_{2.5} species and for the sum of all PM_{2.5} species for which the state
17 believes an insignificance demonstration should be provided.

18
19 **Response to Comment 2:** The commenter is suggesting that, rather than only examining
20 the effects on total PM_{2.5} alone from a precursor reduction, it is also important to
21 evaluate the effects on specific PM_{2.5} species, such as PNO₃, sulfate (PSO₄),
22 ammonium (PNH₄), and secondary organic aerosol (SOA). To account for any model
23 bias, UDAQ evaluated the modeled PM_{2.5} impacts for total PM_{2.5} as well as individual
24 secondary inorganic PM_{2.5} species (particulate nitrate, sulfate and ammonium), which
25 account for over 50% of PM_{2.5} mass.

26
27 **Comment 3:** It appears that in the UPA/Ramboll analysis, precursor contributions to
28 PM_{2.5} were evaluated using absolute model results, not the bias corrected (relative)
29 model results. For a SIP model attainment demonstration, model relative response factors
30 are typically used to correct for model bias. If UDAQ wants to examine absolute modeled
31 precursor impacts, then it is critical to evaluate model bias for individual components of
32 PM_{2.5}. Modeled underpredictions in PM components may lead to an underestimate of
33 absolute modeled precursor impacts. Both absolute and relative model response are
34 important to examine when evaluating the significance thresholds.

35
36 **Response to Comment 3:** In the UPA/Ramboll analysis, PM_{2.5} precursor contributions
37 were quantified using only the difference between two model runs for a given precursor.
38 The analysis used model results with no regard to outside information (e.g., ambient
39 monitor data) to inform analysis conclusions. The commenter is suggesting that other
40 non-model information could be used to scale modeled PM_{2.5} species output in order to
41 reduce model bias. If the model is biased low for nitrate for example, then the change in
42 PM_{2.5} following a reduction in NO_x emissions could be smaller than it actually is in
43 reality. In this instance, using observations of nitrate PM_{2.5} fraction could help
44 compensate. It’s worth mentioning that, to reduce model bias, UDAQ’s Salt Lake SIP
45 modeling used ambient monitor data to scale modeled PM_{2.5} species prior to predicting
46 future design values. EPA’s SMAT-CE software could potentially be used to accomplish

1 a similar bias adjustment for a modeled precursor demonstration. Also, to account for any
2 model bias, in its precursor demonstration analysis, UDAQ scaled absolute modeled
3 precursor impacts by measured PM_{2.5} data from January 1-10 2011, which represents a
4 typical inversion episode. While this analysis is associated with uncertainty, it provides a
5 reasonable estimate of model response to a change in precursor emissions.

6
7 **Comment 4:** The UPA comment letter relies on a recommended threshold found in the
8 EPA's draft guidance for precursor demonstrations. The draft guidance also states that it
9 does not "assure that the EPA will approve a precursor demonstration in all instances
10 where the guidance is followed, as the guidance may not apply to a particular situation
11 based upon the circumstances of a particular nonattainment area." The UDAQ should
12 consider whether the draft guidance thresholds should be used in the circumstances of the
13 Salt Lake City nonattainment area (NAA), particularly in light of the results of UDAQ's
14 attainment demonstration.

15
16 **Response to Comment 4:** UDAQ notes that EPA's (November 17, 2016) draft guidance
17 includes a recommendation to use 1.3 ug/m³ when evaluating for the 24-hour PM_{2.5}
18 NAAQS, whereas the UPA precursor demonstration used a less conservative significance
19 threshold of 1.5 ug/m³ which stems from a more recent update to the "Technical Basis
20 Document" that underlies the draft guidance. The commenter is correct in pointing out
21 that the PM_{2.5} SIP Requirements Rule establishes that the "significance" of a precursor's
22 contribution is to be determined based on the "facts and circumstances of the area."

23
24 UDAQ has indicated it will conduct its own analysis before determining whether it will
25 elect to include a major stationary source precursor demonstration as part of the Serious
26 Area Plan for the SLC nonattainment area. In doing so, UDAQ will give consideration to
27 the range of values presently in the literature, as well as their appropriateness to the
28 unique circumstances of this specific nonattainment area.

29
30 UDAQ also notes that the SIP Requirements Rule establishes that *if* such major stationary
31 source precursor demonstration concludes that: the contribution of the precursor to PM_{2.5}
32 levels (in a concentration-based contribution analysis), or a decrease in emissions of the
33 precursor (in a sensitivity-based contribution analysis) is in fact not significant, then EPA
34 *may* approve the demonstration. UDAQ will also give consideration to the likelihood of
35 any subsequent EPA approval of a stationary source precursor demonstration. **See also**
36 **Response to Comment A-16.**

37
38 **Comment Summary A-4 [submitted by EPA Region 8, Enclosure 2]: SIP**

39 **Narrative:** On page 83, UDAQ states, "The decline in SO₂ emissions is explained by
40 the installation of a wet-gas scrubber at one of the refineries in 2018." Please provide the
41 name of the refinery where the wet-gas scrubber was installed.

42
43 **UDAQ Response to A-4:** The refinery that installed the wet-gas scrubber is Tesoro
44 Refining & Marketing Co. LLC. A glance at SIP Table 4.2 indicates that SO₂ emissions
45 at Tesoro were listed at 544.38 tons/yr. in 2016 and 2017, but decreased to 91.20 tons/yr.
46 in 2019 and 2020. UDAQ will change the language on pp. 83 to read as follows: "The

decline in SO₂ emissions is largely explained by the installation of a wet-gas scrubber at Tesoro Refining & Marketing Co. LLC [one of the refineries] in 2018.”

Comment Summary A-5 [submitted by EPA Region 8, Enclosure 2]: SIP

Narrative: Please provide an explanation for the discrepancy between Table 4.1, page 27 and Table 5.1, page 34 in the SIP Narrative. In Table 5.1, the tons per day (tpd) reductions do not correlate with tpd in Table 4.1 for area sources.

UDAQ Response to A-5: Table 4.1 on pp. 27 shows (in *tons* / day) what was modeled in order to make assessments about 2017, 2019, and 2020. Each modeled assessment is made relative to the actual base year emissions of 2016.

For each of these years, emissions are reported for each of the four source categories... one of which is the Area Source category. In addition to growth, each of the inventories will reflect any emission controls that are either "on-the-books" or "on-the way".

Such is the case with the area source rules. All, if not most, of these rules were made part of the Moderate Area SIP (as RACT). They would therefore have been at least partially effective in the base year of 2016. Since the area is now classified as Serious, the area source rules were re-evaluated to address BACT, and in some cases the rules were made more restrictive.

Table 5.1 on pp. 34 (in *pounds* / day) is intended to illustrate the effectiveness belonging to each of the area source rules... for each pollutant, and for each year in the analysis. The relationship between these two tables is essentially this: The analysis begins with an inventory of uncontrolled emissions, which includes growth. Before these numbers are modeled, any emissions that will be removed from the airshed, due to emission controls, are subtracted from the inventory. In this case, these controls would be the area source rules. Those emissions that are effectively removed from the area source category are shown in Table 5.1. The remainder of the emissions will be released to the airshed, and are therefore modeled in CAMx. It is this remainder that appears in Table 4.1 as belonging to the Area Sources.

Comment Summary A-6 [submitted by EPA Region 8, Enclosure 2]: Reasonable

Further Progress (RFP) and Quantitative Milestones: Under the PM_{2.5} SIP Requirements Rule, the attainment plan must include a Reasonable Further Progress (RFP) plan “that demonstrates that sources in the area will achieve such annual incremental reductions in emissions of direct PM_{2.5} and PM_{2.5} plan precursors as are necessary to ensure attainment of the applicable PM_{2.5} NAAQS as expeditiously as practicable.” The RFP plan must include a “schedule describing the implementation of control measures during each year of the applicable attainment plan.”

Chapter 5 of the SIP Narrative provides emissions reductions for each of the area source rules.

1 However, neither Chapter 8 of the SIP Narrative nor the TSD describes the schedule for
2 implementation of the area source rules, along with implementation of BACT for major
3 stationary sources, as required and outlined above. We recommend adding a table in
4 Chapter 8 to satisfy this part of the RFP plan requirement.

5
6 CAA section 189(c) ties the RFP requirements in section 172(c) to quantitative
7 milestones. Under the SIP Requirements Rule, the plan must contain quantitative
8 milestones "that provide for objective evaluation of reasonable further progress toward
9 timely attainment of the applicable PM_{2.5} NAAQS in the area. At a minimum, each
10 quantitative milestone plan must include a milestone for tracking progress achieved in
11 implementing the SIP control measures, including BACM and BACT, by each milestone
12 date." See 40 CFR 51.1013(a)(2)(iii). We recommend using the table discussed above for
13 RFP, pertaining to 40 CFR 51.1012(a)(1), to help provide a reporting metric to be used to
14 satisfy the minimum quantitative milestone requirement.

15
16 **UDAQ Response to A-6:** UDAQ agrees with the commenter, and will augment Chapter
17 8 of the SIP Narrative with the recommended table(s) indicating the implementation dates
18 and tracking metrics associated with each of the control measures.

19
20
21 **Comment Summary A-7:** The state should estimate the emission reductions that would
22 be achieved by the EPA's heavy-duty diesel engine emissions reduction grant program
23 and assess whether those reductions would approximately equal the reductions necessary
24 to demonstrate RFP for one year.

25
26 **UDAQ Response to A-7:** The emissions reductions from DERA contingency measures
27 are summarized in tables in Chapter 9 of the SIP. RFP is tabulated in Chapter 8. The
28 control strategy analysis summarized in Chapter 5 shows that stationary point sources
29 meet BACT and area sources meet BACM. On-road mobile sources still contribute the
30 majority of emissions, including primary PM_{2.5} and all of the precursors except SO₂.
31 Further emission control in this category extends beyond the authorities of UDAQ. While
32 DERA grants provide a non-regulatory opportunity to reduce emissions, there is currently
33 not enough funding to demonstrate a full year's worth of emissions reductions in the Salt
34 Lake NAA with the proposed contingency measures. Control measures developed to
35 meet increasingly stringent ozone and PM_{2.5} standards in Utah's urbanized areas have
36 likewise become increasingly stringent, and still it is a challenge to attain the 2006,
37 PM_{2.5} NAAQS. This leaves little room for additional reductions that can be set aside as
38 contingency measures.

39
40 The preamble to EPA's PM_{2.5} Implementation Rule says that "contingency measures
41 should provide for emission reductions equivalent to one years share of reductions
42 needed to demonstrate attainment...". However, 40 CFR 50.1014 does not specify any
43 amount of reductions necessary for a contingency measure.

44
45 **Comment Summary A-8:** EPA stated that the UDAQ BACM summary presents reviews
46 of rules in Maine and Washington state, and concludes that R307-208 is more stringent

1 than these rules. It is not clear how this conclusion was reached. Please provide additional
2 information and discussion to support this conclusion.

3
4 EPA requested that UDAQ substantiate the estimated number of outdoor boilers that exist
5 in the nonattainment area.

6
7 **UDAQ Response to A-8:** The Maine and Washington state rules do not prohibit the sale
8 and use of outdoor boilers, while Utah does prohibit the sale and use, therefore, R307-
9 208 is the most stringent state rule.

10
11 UDAQ conducted 2 public hearings when we proposed R307-208 in 2013. The same
12 individual boiler owners showed up for both meetings. Public hearings on proposed rules
13 often do not elicit much attention by the public. That was not the case for R307-208. This
14 rule elicited high level of boiler owner emotions and was elevated publicly when Central
15 Boiler, the major manufacturer of outdoor boilers, hired a prestigious Utah citizen as their
16 lobbyist. The lobbyist first challenged the Air Quality Board authority to ban outdoor
17 wood boilers. When he lost that battle, the lobbyist solicited the Utah legislative
18 Administrative Rules Committee to sunset the rule. This action resulted in national
19 exposure, after all, no state had promulgated a total ban of outdoor wood boilers before.
20 A number of wood burning experts across the country signed a letter to
21 the Administrative Rules Committee stating that the information distributed by the
22 lobbyist was not accurate. Ultimately, the legislature did not sunset the rule. The rationale
23 behind providing this historical summary of the rulemaking for EPA is to impress upon
24 EPA the depth at which UDAQ had knowledge of the subject at hand and inventory at the
25 time.

26
27 Outdoor wood boilers are not normally sold in your neighborhood hearth retailer, they are
28 sold by catalogue. The limited method of distribution was advantageous to UDAQ as we
29 searched the internet making sure that distributors soliciting in Utah were aware of the
30 new ban



31
32
33 Furthermore, an outdoor wood boiler installation in a neighborhood would be instantly
34 recognizable and UDAQ would shortly be advised as well. Smell is the best indicator of
35 wood boilers. When there is no demand for heating from these boilers, they smolder.
36 Low stack temperatures result in poor emission dispersion affecting neighbors who

1 ultimately complain to UDAQ. These units would not “fly under the radar” so to
2 speak.

3
4 UDAQ contracted with ICF International in 2015 to conduct a survey of residents in the
5 seven PM nonattainment counties regarding their home heating and wood burning
6 behaviors. Key objectives of the study included estimating the percentage of households
7 in the target area which burn wood and the volume of wood burned. We implemented the
8 survey consisting of up to four mail contacts over an eight-week period to a
9 representative sample of 8,600 addresses within the seven county area. A total of 2,690
10 completed surveys were received, for a response rate of 33.2 percent (using the American
11 Association of Public Opinion Research’s, or AAPOR’s, RR1 formula). Within the study
12 area, some type of wood burning appliance was reported by 32 percent of households.
13 Fireplaces were the most cited wood burning appliance (21%), followed by inserts (7%)
14 and wood stoves (7%). **Other types of wood burning appliances, such as pellet stoves,**
15 **cordwood central furnace, etc. were reported by three percent of respondents.** This
16 survey validated to UDAQ that the use of outdoor wood boilers stayed flat in the 2 year
17 period since the rulemaking. Outdoor wood boilers were never well established in Utah
18 as wood stoves. UDAQ took the opportunity to ban them before they could be established
19 in the airshed. We are confident that our assessment that 50 units exist within the
20 nonattainment airshed is actually an over estimate.

21
22 **Comment Summary A-9:** EPA states that the Motor Vehicle Emission Budgets
23 (MVEBs) were not clearly identified and precisely quantified. EPA attempted to draw a
24 connection between TSD table “vi”, a countywide on-road mobile source emissions
25 inventory table and the SIP MVEB’s table located in Chapter 7 of the SIP. EPA would
26 like to see additional information and references to the TSD in the SIP, as to how the
27 MVEBs were derived for the SIP.

28
29 **UDAQ Response to A-9:** UDAQ agrees with EPA that the TSD did not clearly show all
30 of the steps involved in constructing the MVEBs within the TSD. UDAQ will add a
31 narrative along with four supporting tables to the TSD that identify and precisely quantify
32 how the MVEBs were derived for the SIP. UDAQ will include a reference to the TSD in
33 the SIP regarding how the MVEBs were derived. A correction will be made to table “vi”
34 in the TSD where the PM2.5 values are identical to the PM10.

35
36 **Comment Summary A-10:** EPA would like to see a brief statement in the SIP regarding
37 the development of the 5% Vehicle Miles Traveled applied growth rate along with a
38 reference to the TSD in the SIP.

39
40 **UDAQ Response to A-10:** UDAQ will add a brief statement in the SIP regarding the
41 development of the 5% VMT applied growth rate along with a reference to the TSD.

Comment Summary A-11: EPA would like some clarification in the TSD regarding how the MVEB trading ratios were derived in addition they want a reference to the TSD included in the SIP narrative.

UDAQ Response to A-11: UDAQ will add clarification to the TSD regarding the trading ratio and include a reference in the SIP.

Comment Summary A-12: [submitted by EPA Region 8, Enclosure 4] **Performance of the air quality models with respect to elemental carbon:** Page 41 of the SIP Narrative provides: "[s]imulated fine crustal matter (CM) and elemental carbon (EC) concentrations were a bit higher than observed. The overestimation in these two primary aerosols were the likely result of a high bias in MOVES 2014a (EC) and the re-suspended road dust calculation tool provided by the EPA (CM)." On page 46, UDAQ concludes, "[t]he model, on the other hand, overestimated EC which can be related to an overestimation of EC in Utah's mobile emissions modeling using MOVES 2014a;" While the EPA agrees that re-entrained road dust estimates are possibly biased high when using AP-42 for Utah conditions, there is no demonstrated bias in MOVES for elemental carbon. EPA requests this language be removed.

UDAQ Response to A-12: Following EPA's recommendation, UDAQ will remove the language stating that the model overestimation of EC is related to a high bias in MOVES 2014a. The SIP Narrative will read as follows:

On pp. 41:

Looking at **Fig. 6.2.2**, observed speciated PM_{2.5} mass from the Hawthorne Chemical Speciation Network (CSN) monitor (January 7), there is good agreement in nitrate (NO₃) and ammonium (NH₄) with the CAMx modeling results. The agreement between modeled and observed NO₃ is a benefit from the ammonia injection. Simulated fine crustal matter (CM) and elemental carbon (EC) concentrations were a bit higher than observed. The overestimation ~~[in these two primary aerosols were the likely result of a high bias in MOVES 2014a (EC) and the re-suspended road dust calculation tool provided by the EPA (CM)]~~ of CM was likely the result of a high bias in the re-suspended road dust calculation tool (AP-42).

On pp. 46:

Conversely, the model performance for organic carbon was quite good for January 7, with modeled and observed concentrations being quite comparable. The model, on the other hand, overestimated EC ~~[which can be related to an overestimation of EC in Utah's mobile emissions modeling using MOVES 2014a] and CM~~. Crustal material was ~~[also] likely~~ overestimated ~~[, likely]~~ due to an overestimation of re-suspended road dust in the emissions inventory.

1 **Rio Tinto**

2
3 **Comment Summary A-13:** Rio Tinto pointed out that the TSD supporting the adoption
4 of Part A.31 of the PM2.5 SIP includes sections titled “Control Strategies” and “Point
5 Source Baseline Projections, BACT”, within the “Control Strategies” section. UDAQ
6 has included the following BACM analysis for KUC: (1) Kennecott Utah Copper - BCM
7 and Concentrator; (2) Kennecott Utah Copper - Power Plant; and (3) Kennecott Utah
8 Copper - Smelter and Refinery. Within the “Point Source Baseline Projections, BACT”
9 section, and UDAQ has included the BACT workbooks for the above listed facilities.

10
11 There is a concern that the inclusion of these documents could lead to the presumption
12 that public comment on UDAQ’s BACT determinations for KUC’s operations subject to
13 the PM2.5 SIP as well as the technical documents supporting those determinations are
14 subject to the current public comment period.
15

16 **UDAQ Response to A-13:** The proposed Part A.31 of the PM2.5 SIP titled “Control
17 Strategies” and “Point Source Baseline Projections” does not grant the opportunity for
18 comments to be received for the Technical support documents associated with the BACT
19 analysis for KUC: (1) Kennecott Utah Copper - BCM and Concentrator; (2) Kennecott
20 Utah Copper - Power Plant; and (3) Kennecott Utah Copper - Smelter and Refinery. The
21 comment period initiated November 1, 2018, considers the Air Quality Board
22 recommended changes to the “Emission Limits and Operating Practices” Section IX, Part
23 H. These revised Part H limitations were associated with the October 3, 2018 Utah Air
24 Quality Board Meeting. Comments on the proposed changes are being accepted through
25 November 30, 2018.
26
27

28 **Comment Summary A-14:** Rio Tinto requested that UDAQ revise the August 20, 2015
29 wildfire exceptional event documentation to include the value for Rose Park, that was
30 below the standard which led UDAQ to exclude it from the submission. Rio Tinto
31 believes that the Rose Park value for that value has regulatory significance thereby
32 demonstrating attainment.
33

34 The Utah Petroleum Association had the same request. The Association submitted a
35 detailed analysis demonstrating that the August 20, 2015 Rose Park PM2.5 filter value of
36 33.3 ug/m3 has regulatory significance in reaching attainment.
37

38 **UDAQ Response to A-14:** The Rose Park August 20, 2015 PM2.5 filter value was
39 elevated due to smoke from western wildfires. It was not included in the exceptional
40 events filing at the time because it did not exceed the standard. Now that we are able to
41 look at the 2015-2017 averaging period, we see that the Rose Park value on August 20,
42 2015 is the 8th high, or the 98th percentile value for that year and that excluding that
43 value as an exceptional event would lower the predicted 2019 value from 35.9 ug/m3 to
44 35.2 ug/m3, thus predicting attainment. UDAQ will submit a notice of intent to EPA and

1 seek EPA's concurrence to resubmit the exceptional event with the Rose Park data. See
2 also Response to Comment A-19.

3
4 **Utah Manufacturing Association**

5
6 **Comment Summary A-15: [submitted by the Utah Manufacturers Association**
7 **(UMA)]:** Members of the UPA have previously shouldered significant costs to
8 substantially curtail emissions in the effort to reach attainment. Further controls from
9 point sources will result in diminishing returns in terms of air quality improvements.
10 Consequently, controls considered by DAQ should be strategically directed and deemed
11 necessary to bring the area into attainment. To that end, UMA supports the comments
12 submitted by the Utah Petroleum Association.

13
14 **UDAQ Response to A-15:** Comment noted by UDAQ.

15
16
17 **Utah Petroleum Association**

18
19 **Comment Summary A-16: [submitted by the Utah Petroleum Association**
20 **(UPA)] Precursor Demonstration:** Based on the reasons presented throughout these
21 comments, UPA recommends that UDAQ adopt a major stationary source precursor
22 demonstration for NO_x, SO_x, VOC, and ammonia, and advocate approval of these
23 demonstrations to EPA.

24
25 Additionally, the WOE discussion in the proposed SIP presents no concerns with the
26 model's capabilities regarding SO_x or VOC, and we see no other objection from UDAQ
27 for these portions of the major stationary source precursor demonstration submitted by
28 UPA. Accordingly, and at a minimum, UPA recommends that DAQ advocate for a
29 major source precursor demonstration for SO_x and VOC.

30
31 Furthermore, considering the very small contribution by the stationary sources to the
32 overall ammonia inventory, UPA recommends that DAQ advocate for an ammonia
33 exemption as well.

34
35 **UDAQ Response to A-16:** UDAQ notes that UPA has submitted its' analyses for each
36 of the four PM_{2.5} precursors (SO₂, NO_x, VOC, and Ammonia). Each analysis concludes
37 that the contribution from major stationary point sources is insignificant when compared
38 to a benchmark of 1.5 µg/m³.

39
40 Of these (Ramboll / UPA) analyses:

41
42 The NO_x analysis is perhaps the most difficult to interpret. The modeled change in
43 PM_{2.5} values, displayed in the matrix of monitor locations and analysis days, indicates a
44 scatter of both positive and negative values. This result may reveal what is called a NO_x
45 dis-benefit, where PM_{2.5} actually increases with a decrease in emissions. While
46 theoretically possible, it is difficult to establish whether the results are in fact

1 representative of current conditions in the Salt Lake Valley. Furthermore, such condition
2 may be transient with respect to time as episodic conditions evolve.

3
4 For VOC the net change in PM_{2.5} is very small. This is likely consistent with the
5 relatively small emissions contribution (roughly 7%) from the major stationary source
6 category.

7
8 For SO_x the net change in PM_{2.5} is highest, yet still below the 1.5 µg/m³ significance
9 level. This result seems consistent with the relative emissions contribution (roughly
10 80%). Still, UPA followed up its (more conservative) concentration-based contribution
11 analysis with a (more refined) sensitivity-based contribution analysis to conclude that the
12 contribution due to major stationary sources was insignificant.

13
14 For Ammonia, the analysis also shows a very small net change in PM_{2.5} due to the
15 contribution from the major stationary source category. As pointed out by UPA, the
16 result would be consistent with the relative emissions contribution (roughly 3%)
17 belonging to the major stationary source category. Yet, the ammonia inventory is itself
18 very uncertain, with 40% of the modeled ammonia having been artificially introduced
19 and therefore not attributable to any of the four general source categories.

20
21 UDAQ also conducted its own analyses (*see attachment*) for each of these PM_{2.5}
22 precursors (SO₂, NO_x, VOC, and Ammonia). The two separate reports were very similar
23 in structure, as would be expected.

24
25 Of particular note, UDAQ made use of the same 1.5 µg/m³ to establish
26 “significance.” EPA’s (November 17, 2016) draft guidance includes a recommendation
27 to use 1.3 µg/m³ when evaluating for the 24-hour PM_{2.5} NAAQS, whereas the UPA
28 precursor demonstration used a less conservative significance threshold of 1.5 µg/m³
29 which stems from a more recent update to the “Technical Basis Document” that underlies
30 the draft guidance. A third value (1.2 µg/m³) has even been discussed in this context,
31 though its basis lies in the Prevention of Significant Deterioration (PSD) program.
32 UDAQ understands that 1.5 µg/m³ is the least restrictive of the three, but also
33 acknowledges that the PM_{2.5} Implementation Rule allows for a less conservative
34 sensitivity-based contribution analysis if the concentration-based contribution analysis
35 does not support a finding of insignificance.

36
37 Still, there were some differences, which included: 1) The use of different emission
38 inventories. UDAQ used a final refined inventory for 2019, while Ramboll used an
39 intermediate inventory because a complete inventory was not yet available at the time
40 their analysis was compiled. 2) UDAQ examined the change in PM_{2.5} over the entire
41 non-attainment area, not just at monitor locations. Spatial fields were plotted for this
42 purpose. 3) Other differences include UDAQ’s scaling of modeled data to measured data
43 from 2011 in order to account for any model bias, 4) UDAQ’s investigation of changes
44 in PM_{2.5} for select individual PM_{2.5} components (nitrate, sulfate and ammonium, which
45 account for most of the PM_{2.5} mass), and 5) Additionally, to consider the potential for a
46 non-linear model response to changes in precursor emissions, particularly NO_x, UDAQ

ran the CAMx Particulate Source Apportionment Technology (PSAT) tool. This module tracks the mass contributions of nitrate (NO_3), sulfate (SO_4) and ammonium (NH_4) from the collection of point sources in the SLC nonattainment area.

UDAQ's conclusions may be summarized as follows:

Again, the NO_x analysis invites some interpretation regarding the potential for a NO_x dis-benefit. UDAQ's analysis also shows a dis-benefit at some locations on some of the analysis days.

However, when adjusted for model bias, the analysis also indicates a change in $\text{PM}_{2.5}$ that is greater than $1.5 \mu\text{g}/\text{m}^3$ at the Ogden (O2) station. The bias adjustment in this case was to apply the relative response of the model to measured $\text{PM}_{2.5}$ data from 2011.

It is also worth noting that when looking at the entire spatial field, values for nitrate (NO_3) exceeding $1.5 \mu\text{g}/\text{m}^3$ may be seen in an area north of the Brigham City monitor. This would also indicate net changes of $\text{PM}_{2.5}$ exceeding $1.5 \mu\text{g}/\text{m}^3$ at these locations.

UDAQ also ran PSAT, which attributes exactly how much of the secondary aerosol (nitrate, sulfate, and ammonium) that may be attributed to the collection of major stationary sources in the SLC nonattainment area. This type of analysis differs from a "brute force" elimination of emissions in that it uses the model in an absolute sense, looking exclusively at the emissions expected from these sources to determine attribution. In this way, the user is able to evaluate the impact from point source emissions at all monitored locations. The PSAT result shows $1.74 \mu\text{g}/\text{m}^3$ of nitrate alone at the Hawthorne station, as well as combined values of all secondary aerosols that exceed $2.5 \mu\text{g}/\text{m}^3$ at Hawthorne and Rose Park.

Yet the question remains: "is the dis-benefit effect realistic considering the actual observations made in the SLC nonattainment area?" And, does this mean the airshed is changing from a NO_x -limited to an oxidant-limited regime? It is of course theoretically possible, but one might also question whether the model has been parameterized well enough to accurately portray the relationship between NO_x and certain oxidants (eg. O_3 and N_2O_5). If not, the modeled results could be misleading.

At this time, and for these reasons, UDAQ will elect not to include a major stationary source precursor demonstration for NO_x as part of the Serious Area $\text{PM}_{2.5}$ SIP for the SLC nonattainment area.

For VOC the net change in $\text{PM}_{2.5}$ relatively small. The highest net change in the value predicted by the model was only $0.62 \mu\text{g}/\text{m}^3$ at the Bountiful location. An examination of the spatial field reveals areas where the $\text{PM}_{2.5}$ change approaches $1.2 \mu\text{g}/\text{m}^3$. As noted above, $1.2 \mu\text{g}/\text{m}^3$ has been used (in PSD guidance) as a similar threshold. However, UDAQ agrees that a $1.5 \mu\text{g}/\text{m}^3$ cut-point is appropriate in this case, and concludes that

1 the net change in PM_{2.5} is insignificant. This result also seems consistent with the
2 relative emissions contribution (roughly 6%) from major stationary sources.

3
4 For SO_x the net change in PM_{2.5} is well over 1.5 µg/m³. The highest net change in the
5 value predicted by the model at a monitor location is 1.54 µg/m³ at Magna. However,
6 when looking at the entire spatial field, the analysis indicates a maximum value of 5.9
7 µg/m³ near the Kennecott smelter. Again, this seems consistent with the relative
8 emissions contribution (roughly 79%) from major stationary sources.

9
10 ***At this time, and for these reasons, UDAQ will elect not to include a major stationary***
11 ***source precursor demonstration for SO_x as part of the Serious Area PM_{2.5} SIP for the***
12 ***SLC nonattainment area.***

13
14 For Ammonia the analysis also shows a very small change in PM_{2.5} (1 µg/m³ max) from
15 the major stationary source category contribution. This is true throughout the entire
16 spatial field. Still, UDAQ remains skeptical of the ammonia inventory, 40% of which
17 has been artificially attributed.

18
19 It is perhaps worth noting that UDAQ recently revised its permitting rules (at R307-403)
20 for PM_{2.5} nonattainment areas, and was unable to conclude that ammonia could be
21 eliminated from New Source Review (NSR), in the SLC nonattainment area, as it had
22 been in the Logan area. UDAQ's contention was (and still is) that it presently lacks the
23 appropriate tools to make such a determination, but that the issue may be revisited at a
24 later time when there is better information at hand.

25
26 ***At this time, and for these reasons, UDAQ will elect not to include a major stationary***
27 ***source precursor demonstration for Ammonia as part of the Serious Area PM_{2.5} SIP***
28 ***for the SLC nonattainment area.***

29
30
31 Also addressed in the UDAQ report, but not in the UPA report, is the potential
32 aggregation of impacts ascribed by each of the singular PM_{2.5} precursor analyses.

33
34 Noting that it may not be appropriate to simply add together each independent result,
35 UDAQ ran the model with no emissions from any of the four precursors belonging to the
36 major stationary sources.

37
38 Results from this "composite" analysis showed multiple exceedances of 1.5 µg/m³
39 throughout the episode, at multiple monitors in SLC nonattainment area. EPA's draft
40 guidance is silent on the issue of "composite" analyses, but it strikes UDAQ as a
41 legitimate question given the facts and circumstances of the SLC nonattainment area.

42
43 Speaking more directly to UPA's petition that UDAQ at least incorporate a precursor
44 demonstration for SO_x and VOC, one might similarly address the additive nature of these
45 two precursors. Assuming, for the sake of discussion, that it would be acceptable to
46 simply add together the two independent results, one could look at the impact of SO_x and

VOC together. In this case the results would show net changes in PM_{2.5} that would exceed 1.5 µg/m³. Obviously this is a forgone conclusion in that the SO_x analysis by itself exceeds the significance threshold.

A final thought concerning the VOC result:

As with the other PM_{2.5} precursors, UDAQ is electing not to include a major stationary source precursor demonstration for VOC as part of the Serious Area PM_{2.5} SIP for the SLC nonattainment area at this time. However UDAQ also notes that the BACT review conducted as part of this SIP resulted in very little additional control for VOC emissions, accompanied by very little additional cost to the major stationary sources.

Were the results of this BACT analysis instead to compel a significant cost to the major stationary sources, UDAQ might be persuaded to invest the additional time necessary to exclude VOC, or for that matter, any precursor from its resulting control strategy.

It is worth noting that UDAQ makes this judgment in light of the BACT analysis, and resulting cost estimates therein, that it proposes to include as part of the overall SIP. UDAQ understands that the SIP must still be reviewed and acted upon by the EPA, and as part of that process, the final BACT determinations could potentially be revised.

Should the resulting control strategy of this Serious Area SIP become substantially more costly, UDAQ might potentially intervene with an addendum to its Plan.

Comment Summary A-17: [submitted by the Utah Petroleum Association (UPA)]:

Timing considerations: DAQ has indicated that it will be performing its own analysis concerning the major stationary source precursor emissions, in consultation with the EPA. It also expressed the need to continue with the rulemaking process required to implement BACT in the event that such additional controls are ultimately deemed necessary. UPA believes that these efforts should proceed on parallel tracks. Furthermore, a final determination of whether to adopt the additional precursor controls at point sources (proposed in Part H) should wait until the DAQ's analysis has been completed and can determine whether such additional controls are necessary or not. Adoption of such additional controls would be inconsistent with a final determination that they are not necessary.

Accordingly, UPA requests that DAQ not conclude a final rulemaking on Part H until it reaches a conclusion on the precursor demonstration. To do otherwise would be contrary to the Utah requirement that the Board adopt only those controls determined necessary.

Should the Board nonetheless decide to take final action on Part H prior to that time, UPA believes it should do so provisionally, making Part H effective contingent upon the outcome of a final decision on the precursor demonstration.

UDAQ Response to A-17: As stated in the responses to **Comment A-16**, UDAQ is electing not to include a major stationary source precursor demonstration for any of the PM_{2.5} precursors at this time. Had UDAQ instead elected to do so, the commenter makes a valid point in that EPA would still have had to approve the demonstration in order that BACT controls for such pollutant(s) would thereby not be required, and this takes time. Meanwhile, by state law, a source may have been faced with a deadline for purchase and installation of control equipment which ultimately may not have been required. Had this been the case, a provisional construction of Part H could have been a suitable path. Since, however, a major stationary source precursor demonstration will not be part of the SIP. It will not be necessary to wait for EPA to render its decision on any such precursor demonstration. Part H may be acted upon by the UAQB without delay.

Comment Summary A-18: [submitted by the Utah Petroleum Association (UPA)]: Modeling Analyses **UDAQ Response to Comment A-18 are presented throughout:**

UPA concurs with much of UDAQ's analysis and overall conclusions in support of its proposed attainment demonstration. UPA's comments demonstrate that the major stationary source precursor demonstration for NO_x, SO_x, VOC, and ammonia is consistent with the State's modeled attainment demonstration and with the proposed SIP. In summary, UPA presents the following comments in support of this conclusion:

Bullet 1: If the model is an appropriate tool for the attainment demonstration, it must necessarily be an appropriate tool for a precursor demonstration. Reliance on the model as a reliable predictor for future year attainment necessarily implies the model's capabilities for purposes of making a precursor demonstration.

Response to Bullet 1: The model's ability to conduct a reliable SIP attainment demonstration is assessed by conducting a model performance evaluation (MPE). Utah DAQ conducted its MPE according to EPA guidance ("Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM_{2.5}, and Regional Haze", 2014). The MPE entails quantifying model performance for a specific meteorological episode and emissions inventory (EI). For the purposes of the MPE, 2011 wintertime emissions were used; This choice corresponds with the 2011 wintertime meteorological episode used in Utah DAQ's modeling. The MPE conducted by UDAQ is referred to as an "operational" model evaluation.

A "dynamic" model evaluation with respects to evaluating EI changes was not conducted by UDAQ. A major issue is that it's expensive to have quality meteorological model data available for multiple episodes. WRF performance for other meteorological episodes considered by UDAQ were not as good for the Salt Lake Valley as the 2011 episode ultimately chosen for the SIP modeled attainment demonstration. When evaluating the modeled response to EI changes, it would have been difficult to disentangle the effects due to WRF performance from the effects due to EI changes. A dynamic performance evaluation would be ideal in assessing the model's ability to conduct a precursor demonstration. But for the aforementioned reasons, a dynamic performance evaluation was not considered.

Bullet 2: If UDAQ determines not to use the model to determine whether imposing additional controls on major stationary source precursor emissions are necessary, then it must provide some alternative basis for determining that additional controls are, in fact, necessary before it proceeds to adopt such controls.

Response to Bullet 2: Regardless of whether the Serious Area SIP for the SLC PM_{2.5} nonattainment area includes a major stationary source precursor demonstration, UDAQ must determine BACT for PM_{2.5} as well as PM_{2.5} precursors. This is required by the PM Implementation Rule *unless* the EPA has approved the demonstration. UDAQ cannot know whether the EPA has approved the precursor demonstration until after the SIP, including the BACT element, has been submitted.

Bullet 4: UPA agrees that the majority of the ambient PM_{2.5} problem in the Salt Lake City nonattainment area results from secondary PM_{2.5} arising from precursor emissions. On the other hand, UPA finds that a substantial portion of the nonattainment area ambient PM_{2.5} arises from direct PM_{2.5} emissions.

Response to Bullet 4: A non-negligible portion of wintertime peak PM_{2.5} mass is associated with direct PM_{2.5} emissions. For example, UDAQ estimates that along with car exhaust, residential wood-smoke accounts for a significant fraction of primary organic carbon (POC). POC, itself, could account for nearly 10% of PM_{2.5} filter mass during peak wintertime PM_{2.5} events. However, rules are already in place to ban residential wood-smoke emissions during periods when elevated wintertime PM_{2.5} is likely observed. Statewide rules that mandate fugitive dust suppression, have also been enacted already. It's not clear what other controls of direct PM_{2.5} would make meaningful contributions to lowering wintertime PM_{2.5} pollution.

Bullet 6: Notwithstanding its conclusion that the model performs well, the weight of evidence discussion ("WOE discussion" or "WOE") offered in the attainment demonstration seems to inconsistently and, in several instances, we believe incorrectly, question the model's capabilities. Ramboll, the developers of the CAMx model used for both the attainment demonstration and the major stationary source precursor demonstration, performed an evaluation of the WOE discussion which we include as part of these comments. UPA recommends modifying the WOE discussion in the proposed SIP in accordance with the Ramboll evaluation of it. We highlight two of Ramboll's observations in its evaluation of the WOE:

1. The model replicates observed conditions well and its response to emission reduction may be considered reliable in view of the models overall performance evaluation.

2. Model-measurement comparisons suggest that the model may be less NO_x-saturated than actual conditions at times, suggesting that in reality, additional NO_x controls in the Salt Lake City nonattainment area may be even less effective than the model predicts.

Response to Bullet 6: CAMx is a state-of-the-art model approved by the EPA for the purposes of conducting a SIP modeled attainment demonstration. Much of the uncertainty that underlies UDAQ's modeling efforts has to do with model inputs, not the model itself. For example, UDAQ's usage of a coarsely resolved ammonia (NH₃) emissions inventory. However, these inputs were considered the best available at the time of conducting the modeled attainment demonstration. UDAQ also made modifications to the model to account for local conditions impacting PM_{2.5} formation in the region. Some of these changes (e.g., ammonia deposition, urban surface albedo) have been incorporated by Ramboll in recent versions of CAMx.

Modeled NO_x and O₃ are on par with 2011 Hawthorne measurements, with some exception of January 5 - 6, 2011 with less NO_x and more overnight O₃ being produced in the model. But overall, it's not clear if the model is less NO_x saturated than measurements suggest.

Comment Summary A-19: [submitted by the Utah Petroleum Association (UPA)]: UPA recommends making two enhancements to the monitoring data that provide the basis for the attainment demonstration. These are discussed here in A-19 and below in A-20.

Enhancement 1: Exceptional Event at Rose Park: The UPA believes that UDAQ should move its discussion of the August 20, 2015, exceptional event for the Rose Park monitor from the Supplemental Analysis (portion of 6.2 Weight of Evidence) to the principal future year modeled attainment demonstration.

As presented, the modeled attainment test for the Rose Park monitor falls just short of attainment, predicting a 2019 future year design value of 35.9 µg/m³. Excusing the August 20, 2015 value collected at Rose Park as an exceptional event would effectively allow UDAQ to predict attainment in the modeled attainment demonstration for 2019.

Even though the Rose Park monitor did not exceed the level of the standard on that date, the monitor result from that date could have been addressed in the formal exceptional event demonstration.

UDAQ Response to Comment A-19: UDAQ agrees with the commenter that the August 20, 2015 value collected at Rose Park can be flagged as an exceptional event, even though it did not exceed the level of the 24-hour PM_{2.5} standard. Clearly, its effect on the monitored design value for this SIP gives it regulatory significance.

UDAQ has recently provided EPA with the documentation necessary to exclude this value for regulatory purposes, and is discussing with the Agency the most appropriate way to do so.

1 However, at this time UDAQ is not proposing to restructure and re-propose the SIP in
2 order to make use of such data exclusion in consideration of the modeled attainment
3 demonstration. UDAQ remains satisfied that the demonstration at large still shows a
4 likelihood of attainment in 2019. **See also Response to Comment A-14.**
5
6

7 **Comment Summary A-20:** Enhancement 2: UPA recommends substituting the
8 maximum measured values during the 2nd and 3rd quarters for all missing data in those
9 quarters of 2016.
10

11 **UDAQ Response to A-20:** A similar methodology to that proposed by the commenter is
12 discussed in 40 CFR 50 Appendix N 4.2(c)(i). It is only allowed for quarters with
13 completeness less than 75% but at least 50 percent:
14

15 “Identify for each deficient quarter (i.e., those with less than 75 percent but at
16 least 50 percent data capture) the highest reported daily PM_{2.5} value for that
17 quarter, excluding state-flagged data affected by exceptional events which have
18 been approved for exclusion by the Regional Administrator, looking across those
19 three quarters of all three years under consideration. If, after substituting the
20 highest reported daily maximum PM_{2.5} value for a quarter for all missing daily
21 data in the matching deficient quarter(s) (i.e., to make those quarters 100 percent
22 complete), the procedure yields a recalculated 3-year 24-hour NAAQS test DV
23 (TDV_{max}) less than or equal to the level of the standard, then the 24-hour PM_{2.5}
24 NAAQS DV is deemed to have passed the diagnostic test and is valid, and the 24-
25 hour PM_{2.5} NAAQS is deemed to have been met in that 3-year period.”
26

27 The Rose Park monitor meets the completeness requirement for all four quarters; 97%,
28 84%, 82%, and 91% consecutively. As such, if data substitution is to be implemented to
29 increase the number of valid days it should be done for all four quarters. If this data
30 substitution were to be implemented, the 98th percentile value for 2016 at the Rose Park
31 station would increase and negate any potential benefit from the data substitution.
32

33 Alternatively, UDAQ did investigate the possibility of using measurement from the
34 Hawthorne station for the missing values at Rose Park. When this substitution was
35 completed the 98th percentile value for 2016 at Rose Park was the same as it had been.
36 This is due to a missing day during an inversion period December of 2016.
37

38 **Comment Summary A-21:** [submitted by the Utah Petroleum Association
39 (UPA)]: Weight of Evidence discussion **UDAQ Responses to Comment A-21 are**
40 **presented throughout:**
41

42 The proposed SIP includes a WOE discussion, part of which purports to explain why the
43 agency believes the model does not respond well to NO_x controls. The WOE emphasizes

1 potential concerns regarding the ability of the model to predict ambient changes in PM_{2.5}
2 levels resulting from reductions in NO_x emissions.

3
4 UPA retained Ramboll, the developers of the CAMx model, to evaluate the WOE
5 discussion in the proposed SIP. The Ramboll evaluation report entitled, "Comments on
6 Serious Area PM_{2.5} State Implementation Plan for the Salt Lake City, UT Nonattainment
7 Area: Section IX. Part A.31. Control Measures for Area and Point Sources, Fine
8 Particulate Matter; Chapter 6, Attainment Demonstration; and Section 6.2, Weight of
9 Evidence", included as part of these comments as Attachment A, provides additional
10 discussion for the following points:

11
12 Based on the discussion in the Ramboll evaluation report, UPA recommends revising the
13 WOE discussion in the proposed SIP accordingly.

14
15 **First Bullet:** The WOE offers insufficient evidence that the model's response is
16 inconsistent with observed conditions and trends to support the hypothesis that the model
17 does not respond appropriately to emission reductions due in part to model uncertainty
18 associated with PM-forming chemical interactions.

19
20 **Response to First Bullet:** The Weight of Evidence (WOE) discussion notes that the
21 modeling guidance allows for the consideration of supplemental information and analyses
22 when assessing future attainment in an area such as SLC. Specifically identified as
23 candidates for such supplemental information, are trends in both emissions and ambient
24 (monitoring) data. These observed trends reflect past and current conditions in the
25 airshed. Modeled evaluations, by contrast, are theoretical in their construction and will
26 always include some level of uncertainty.

27
28 The WOE does not state conclusions regarding the model's ability to re-create observed
29 conditions or the model's ability to respond accurately to emissions reductions. By
30 "model uncertainty", it should be understood that we do not know the performance
31 impacts (if any) from the issues raised in the WOE. However, the uncertainties raised in
32 the WOE could explain why modeled future design values (FDV) for Salt Lake County
33 monitors were higher than expected given significant future-year emissions reductions.

34
35 **Second Bullet:** A calculation based on emission inventories and design values for the
36 Salt Lake City nonattainment area suggests that model-estimated 2019 design value
37 projections are consistent with observed trends in PM_{2.5} concentrations and precursor
38 emissions.

- 39
40 a. The Speciated Modeled Attainment Test (SMAT) relies on a PM_{2.5} speciation
41 based on 2011 measurements rather than speciation for 2016 consistent with the
42 base year emission inventory. This is inconsistent with EPA modeling guidance,
43 which recommends using speciated measurements from the base year for the
44 SMAT. The design value projections could be sensitive to this choice.

Response to Second Bullet: Regarding Step 7 of the calculation referenced above, UDAQ disagrees that not using 2016 monitored speciation data is a “serious omission”. To test the sensitivity of the design value projections against the choice of speciation year, UDAQ conducted multiple SMAT sensitivity runs where different speciation years were used. Although the EPA modeling guidance recommends using speciated measurements from the base year when running SMAT, UDAQ applied the speciation data from 2011 since, compared to other years, the speciation profile for 2011 was more representative of typical wintertime inversion episodes.

Third Bullet: The actual chemical environment appears to be influenced by the lack of oxidants relative to the abundant availability of NO_x (an oxidant-limited condition). The model replicates observed conditions well and its response to emission reduction may be considered reliable in view of the models overall performance evaluation.

Response to Third Bullet: The Utah Wintertime Fine Particulate Study Final Report suggests that North Salt Lake County may be more NO_x-rich as compared to the rest of the Wasatch Front. The model performance evaluation (MPE) in the technical support documentation (TSD) shows good agreement between modeled and observed PM_{2.5} composition and mass; particularly as model performance relates to secondary PM_{2.5} species. The model’s general NO_x performance is good, but the model’s performance with regards to VOC’s and oxidants is not quite as good. So, it’s unclear how accurate is the model’s response to emissions reduction.

Fourth Bullet: Statements in the WOE about nitryl chloride chemistry are incorrect. The version of the model used by UDAQ does in fact include the formation of ClNO₂ and nitric acid (HNO₃) via heterogeneous nighttime reactions among hydrochloric acid (HCl) and dinitrogen pentoxide (N₂O₅), and the daytime photolysis of ClNO₂ generating nitrogen dioxide (NO₂) and chlorine radicals.

Response to Fourth Bullet: While the version of the CAMx model used by UDAQ includes the formation of nitryl chloride (ClNO₂) and nitric acid via heterogeneous nighttime reactions among hydrochloric acid (HCl) and dinitrogen pentoxide (N₂O₅), the model does not include the chemical pathway where ClNO₂ is formed through the heterogeneous uptake of N₂O₅ on chloride-containing particles. This pathway is particularly active in the Salt Lake Valley, where ammonium chloride aerosol accounts for 15% of PM_{2.5} mass during high-PM_{2.5} episodes. This heterologous pathway for N₂O₅ uptake on Cl-containing particles is the pathway that UDAQ is referring to in the weight of evidence analysis.

Fifth Bullet: Model-measurement comparisons suggest that the model may be less NO_x saturated than actual conditions at times, suggesting that in reality, NO_x controls in the Salt Lake City nonattainment area may be even less effective than the model predicts.

Response to Fifth Bullet: Comparisons between observed and modeled NO_x concentrations show generally good agreement across the episode save for two PM_{2.5}

1 concentration build-up days prior (January 5 - 6). It's not clear if the effects from NOx
2 controls in the Salt Lake nonattainment area would be exaggerated in the model.
3

4 **Sixth Bullet:** Given the WOE emphasis on ammonia uncertainty, the analysis needs a
5 quantitative analysis of how the modeled nitrate reacts to the ad hoc ammonia "injection",
6 an investigation into the effects of ammonia uncertainty on particulate matter formation,
7 and quantification to provide context for the attainment demonstration results.
8

9 **Response to Sixth Bullet:** UDAQ used an iterative process to calculate how much
10 ammonia (NH₃) emissions would ultimately be injected into the modeling domain.
11 Modeled NH₃ was compared to ambient NH₃ measurements taken at different Wasatch
12 Front counties. Ultimately, modeled NH₃ concentrations are considered in range of
13 observed NH₃. Particulate nitrate (PNO₃) model performance improved due to ammonia
14 injection, but PNO₃ performance wasn't the primary criteria when considering the
15 amount of ammonia injected. The ammonia injection process is detailed in the technical
16 support documentation (TSD).
17

18 **Seventh Bullet:** Crustal matter is not inert. Over-predictions of crustal matter can affect
19 the total nitrate budget and may slightly increase particulate nitrate reduction from NOx
20 controls.
21

22 **Response to Seventh Bullet:** While crustal material can provide a surface onto which
23 nitric acid can condense to form particulate nitrate - a pathway that is included in CAMx
24 -, the contribution of crustal material to the total nitrate budget is expected to be small.
25 Although crustal material is overestimated in the model (modeled contribution to PM_{2.5}
26 of 8.5% compared to measured contribution to PM_{2.5} of 1.8% on peak PM_{2.5} days), its
27 contribution and relative abundance is still small compared to that of ammonia, which is
28 an important nitric acid neutralizing agent. The impact of crustal matter overprediction on
29 the total nitrate budget and particulate nitrate reduction from NOx controls is therefore
30 expected to be minor. Moreover, further research and measurements are needed to better
31 understand the role of crustal matter in PM_{2.5} chemistry in the Salt Lake airshed.
32
33

34 **Comment Summary A-22 [submitted by the Utah Petroleum Association (UPA)]:**
35 **Statement in State Bulletin:** The Utah State Bulletin public notice for the major
36 stationary source precursor demonstration includes several statements, including
37 concerns, expressed by UDAQ with the precursor demonstration. The following provides
38 UPAs responses to each statement:
39

40 · UPA agrees that UDAQ should perform its own major stationary source precursor
41 demonstration analysis in conjunction with EPA.
42

43 · To the statement that "Ambient PM_{2.5} in the [Salt Lake City nonattainment area]
44 airshed is largely composed of secondary PM_{2.5} formed by precursors, not primary
45 [direct] PM_{2.5}." Direct PM_{2.5} contributes substantially to the Salt Lake City

1 nonattainment area as well as precursor emissions and must be accounted for in order to
2 develop an effective long-term attainment strategy.

3
4 · To the statement that "...empirical evidence points to the success in declining
5 concentrations of ambient PM_{2.5} from controlling precursor emissions." While UPA
6 agrees that precursors contribute generally to PM_{2.5} levels in the airshed and that existing
7 controls of those emissions have aided in the current attainment trajectory, the science
8 shows that imposing additional controls on the diminishing inventory of precursor
9 emissions from major stationary sources would make an insignificant contribution to
10 reducing ambient PM_{2.5} levels in the Salt Lake City nonattainment area. Accordingly,
11 these sources should not be subject to additional controls for their precursor emissions.

12
13 · To the statement that "...Utah continues to look at controls that may only produce
14 marginal benefits. Therefore, the threshold established in the draft guidance may not be
15 appropriate in the [Salt Lake City nonattainment area], particularly when looking at the
16 precursors cumulatively." UPA recommends that, EPA existing precursor demonstration
17 regulations and guidance serve as the standards and criteria for the major stationary
18 source precursor demonstration in Utah.

19
20 · To the statement that the "...weight of evidence discussion ... illustrates potential
21 shortcomings in the model" and that "UPA's analysis with the same model may have
22 perpetuated these same shortcomings." UPA comments that the model performs well, as
23 stated throughout the TSD for the model performance evaluation and throughout the
24 model performance evaluation section of the proposed SIP.

25
26 **UDAQ Response to A-22:** UDAQ acknowledges the counterpoints made by UPA, and
27 notes furthermore that they have been addressed throughout this document. However, the
28 context of these concerns speaks to the public notice made in the Utah State Bulletin and
29 not to the proposal itself.

30
31 **Comment Summary A-23:** In addressing BACM as it applies to Residential Wood
32 Combustion, UDAQ only looked beyond the four serious NAAs identified if those areas
33 had not enacted a comparable area source rule. Such a restriction is in conflict with
34 section 51.1010, which does not limit UDAQ's review to serious nonattainment areas
35 (NAAs). UPA raises additional concerns throughout its comments. Each is addressed
36 below:

37
38 **UDAQ Response to A-23:** The BACM analysis focused on serious nonattainment areas
39 with the rationale that those areas would have the most advanced/strict control measures
40 approved by EPA. The BACM analysis was not although limited to serious
41 nonattainment area rules. The BACM analysis states, "Additional air district rules may
42 also be reviewed if the air districts listed" (i.e., serious nonattainment areas for PM_{2.5}
43 and precursors) in the BACM analysis, "do not have a comparable UDAQ rule." Section
44 51.1010(2)(ii) states, "The state shall survey other NAAQS nonattainment areas in the
45 U.S. and identify any measures for direct PM_{2.5} and PM_{2.5} plan precursors...." It does
46 not specifically limit us from focusing our survey on serious nonattainment areas. It

1 would be highly unlikely that moderate nonattainment areas would have BACM rules
2 rather than RACM rules. Ultimately, we discovered that many of our area source rules
3 are more stringent than BACM. For example, Utah is the only state we are aware of that
4 has banned outdoor wood boilers.

5
6 UPA Comment: Mounting evidence that wood residential burning contributes
7 significantly to the Salt Lake NAA. UDAQ may have underestimated the emissions
8 attributable to wood residential burning.

9
10 UDAQ Response: Emissions inventories are continuously improved as new information
11 becomes available. UDAQ is scheduled to conduct additional wood residential burning
12 research during the 2018-2019 winter.

13
14 UPA Comment: UDAQ failed to evaluate portions of the San Joaquin Valley Air
15 Pollution Control District (SJVAPCD) Rule 4901. UPA provided specific comparisons
16 between Rule 4901 and R307-302.

17
18 (1) Burn ban: Rule 4901 burn ban threshold for Level One is at 20 ug/m3 as compared to
19 25 ug/m3 in R307-302.

20
21 UDAQ Response: Rule 4901 Level One threshold is lower than R307-302 but it does not
22 include all wood burning devices. SJVAPCD offers owners of EPA certified stoves who
23 pay a registration fee to burn during their Level One restriction period. R307-302 does
24 not offer any type of device an exemption from the restricted burn days, including EPA
25 certified wood stoves.

26
27 (2) UPA cites section 5.6.1.2 that permits certain type of burning when restricted burning
28 is in effect. UPA then compares it to R307-302-3(4), insinuating that it is less restrictive
29 than Rule 4901.

30
31 UDAQ Response: We do not understand UPA's rationale for this comment as R307-302
32 is clearly more restrictive since only sole source homes who are registered with UDAQ
33 may burn wood during restricted periods.

34
35 (3) UPA comparison of rule text regarding allowable wood burning devices that may be
36 sold.

37
38 UDAQ Response: While Rule 4901 section 5.1.1 is more descriptive than R307-302-6(1),
39 they ultimately mean the same thing and that is that only EPA certified wood burning
40 devices may be sold, installed or transferred.

41
42 (4) UPA Comment: Section 5.2.1 of Rule 4901 restricts the sale of a home containing an
43 uncertified wood burning device.

44
45 UDAQ Comment: UPA is correct, Rule 4901 is more stringent than R307-302-6(2) that
46 offers an exemption for wood burning devices that already exist in the home before the

1 sale. UDAQ has determined that the provision in Rule 4901, Section 5.2.1 is likely more
2 restrictive than BACM and is more akin to MSM because real estate provisions are not
3 commonly included in wood burning rules. There has also been a formal rejection of this
4 concept by the Utah Real Estate Association during past SIP public rule making comment
5 period.

6
7 (5) UPA Comment: New residential development restrictions on the types and amount of
8 wood burning devices.

9
10 UDAQ Comment: UPA is correct, R307-302 does not include similar a restriction
11 because the Air Quality Board does not have the authority to amend the housing code.

12
13 (6) UPA Comment: Rule 4901 Section 5.1.3 requires retail vendors to provide the public
14 with wood burning awareness information.

15
16 UDAQ Comment: UPA is correct, R307-302 does not include an equivalent provision.
17 UDAQ may consider this provision for future rule revision.

18
19 (7) UPA Comment: UPA states that R307-302 does not have an equivalent provision in
20 Rule 5.4.1 section 5.4.1, seasoned wood sales requirement.

21
22 UDAQ Comment: UPA is incorrect, R307-302-5(3) prohibits the burning of all wood
23 that is not seasoned, which is actually broader than just sold wood.

24
25 In summary, UPA states that UDAQ has not adopted all of the provisions of rule 4901
26 pursuant to 40 CFR 51.1010. We disagree that all provisions of any or all rules surveyed
27 as part of the BACM analysis must be adopted by UDAQ. What is BACM in SJVAPCD
28 is not necessarily BACM in the Salt Lake NAA. The purpose of the rules survey is to
29 gain ideas of control strategy that MAY be appropriate for a specific nonattainment area
30 and that may lead to gains toward attainment. The only provision in Rule 4901 that is not
31 found in R307-302 that may actually result in measurable gains toward attainment is the
32 restriction of wood burning devices in new development. We believe that such restriction
33 is actually MSM and is more appropriate to be legislated through building code.

34
35 UPA Comment: UDAQ's conclusion that R307-302 is more stringent than the
36 corresponding San Joaquin control measures is predicated on the flawed premise that
37 R307-302 will achieve 100% compliance with the burn ban. Under this hopeful, but
38 unrealistic, premise, UDAQ concludes that there is simply no reason to evaluate other
39 measures.

40
41 UDAQ Response: UDAQ has published research data that has shown that burn ban
42 compliance is in fact lower than expected. We agree with UPA that R307-302 may be
43 enhanced through a public stakeholder process, including a MSM control measure of
44 restricted real estate sale of uncertified stoves. Nonetheless, as stated above, revisions to
45 R307-302 within the authority of the Air Quality Board would not likely result in
46 substantial gains toward attainment. A housing code change restricting amount of wood

1 burning appliances that may be installed in new development would be required to realize
2 substantial gains toward attainment. Housing code amendment is the purview of the
3 Legislature and not the Air Quality Board. Conversion of existing residential wood
4 burning appliances to gas is another way to gain measureable emission reductions but
5 requires huge sums of funding. UDAQ is currently implementing a conversion program
6 using EPA grant funding and is also working on the next Airshed grant proposal for more
7 conversion funding.

8
9 UPA Comment: UDAQ failed to survey the residential wood combustion controls from
10 numerous other NAAs. UPA specifically points out Fairbanks, AK, Tacoma, WA, and
11 Portola, CA.

12
13 UDAQ Response: Fairbanks staff and contractors have consulted with UDAQ staff
14 numerous times over the course of their SIP development, which is focused upon
15 residential wood combustion. Consequently, we are well aware of the Fairbanks SIP
16 development. Their SIP is due to EPA December 2018. The BACM analysis was
17 conducted before the Fairbanks Rule 18 could be evaluated and approved by EPA. It is
18 inappropriate to consider a nonattainment rule before EPA has acted on it. Further, the
19 Fairbanks voter-approved Home Heating Reclamation Act (Proposition 4) has relieved
20 the Borough of the authority to restrict wood burning which raises the specter of the
21 rulemakings future.

22
23 UPA specifically points to the Tacoma, WA requirement of not more than 20% wood
24 moisture content. EPA does not define the term seasoned wood. The Chimney Safety
25 Institute of America defines seasoned wood as having a moisture content between 20-
26 25%. UDAQ chose to use the upper boundary to provide a margin (see R307-302-1(2)).

27
28 UPA also points out that Tacoma, WA has issued emission standards for solid fuel
29 burning devices. UDAQ is not qualified to develop emission standards for devices nor do
30 we have a way to test devices. We leave that business to the EPA, as do many other
31 states.

32
33 UPA cites the Puget Sound Clean Air Agency regulation 1-13.07 that requires uncertified
34 stoves to be disposed of by September 30, 2015. The Utah Legislature made it clear via
35 House Bill 396 in 2015 that UDAQ does not have the authority to ban wood burning.
36 Consequently, UDAQ is careful to avoid any rule making that appears to violate the spirit
37 of HB 396.

38
39 UPA cites the City of Portola Ordinance No. 344 that includes a real estate wood burning
40 stove removal requirement, a wood moisture content of 20% and a retailer wood burning
41 information decimation requirement to its customers. All of these have already been
42 discussed in text above.

43
44 UPA also cited wood stove registration and inspection as an option, and a number of
45 other requirements that would require fiduciary authority that the Air Quality Board does
46 not have.

1
2 UPA Comment: UDAQ should acknowledge that the contingency measure in R307-302-
3 3(5) that lowers the burn ban threshold to 15 ug/m3 has been triggered when we did not
4 attain the NAAQS.

5
6 UDAQ Response: In practice, UDAQ calls restricted burning days in accordance with the
7 provision of R307-302-3(4), allowing UDAQ to restrict burning when we are able to
8 forecast a coming inversion. Consequently, UDAQ could restrict burning when the
9 ambient PM2.5 level is below 15 ug/m3.

10
11 UPA Comment: VOC and SO2 emission from wood burning were not included in the
12 BACM analysis.

13
14 UDAQ Response: That is not correct, VOC and SO2 emissions from wood burning were
15 covered in the BACM.

16
17 UPA Comment: R307-302-5 does not prohibit the use of coal in the Salt Lake NAA.

18
19 UDAQ Response: Before 2012, R307-302 only applied to wood burning. In August of
20 2012, the Air Quality Board approved the addition of the term “solid fuel,” thereby
21 moving away from strictly prohibiting the burning of wood. Subsequently, the Board
22 changed the name of the rule to Solid Fuel Burning Devices...thereby regulating all solid
23 fuels (i.e., including coal) except for those that are sole source of heating as permitted by
24 statute.

25
26 UDAQ knows that some coal burning does exist in mostly remote areas of the Salt Lake
27 NAA via our management of the sole source registry. The Legislature provided \$500,000
28 for the conversion of sole source homes on the Registry to natural gas/propane. Some of
29 those homes used coal for heating and had to switch to propane because natural gas is not
30 available in their area. Overall, the natural gas distribution in the Salt Lake NAA is well
31 developed such that a large majority of the residences have access to natural gas. The
32 Legislature has repeatedly advised UDAQ that we must not unduly infringe on residential
33 rights. Prohibiting coal burning without compensation for the conversion would be an
34 infringement. Further, most coal burning that we are aware of meet the definition of sole
35 source. Banning all coal burning would be counter to the statutory rights of sole sources.
36 Since the Air Quality Board does not have primacy over statute nor fiduciary authority, it
37 would be illegal and irresponsible to propose a coal burning prohibition.

38
39 **Wasatch Clean Air Coalition**

40
41 **Comment Summary A-24:** [submitted by the Clean Air Coalition]: U.S. Magnesium

42
43 Ammonium chloride contributes up to 15% of the PM2.5 on exceedance days. A 2015
44 study by Randy Martin “Measurement of Ambient Hydrochloric Acid near Utah’s Great
45 Salt Lake” eliminated the GSL as well as the oil refineries as sources for the chloride, and
46 includes a contour plot that clearly points to U.S. Magnesium as [the] source. The Utah

Petroleum Association also commented to the effect that U.S. Magnesium is the only significant source of chloride emissions in the SLC area, and that it contributes “significantly” to nonattainment. Utah should impose controls on U.S. Magnesium as a necessary step towards achieving attainment.

UDAQ Response to A-24: While aerosol chloride and HCl account for a significant fraction of PM_{2.5} during wintertime episodes, their sources are unclear. The contribution of US magnesium to HCl and chlorine emissions is particularly unclear. While recent measurements (Randy Martin's "Measurement of Ambient Hydrochloric Acid near Utah's Great Salt Lake") suggested that US magnesium is a major source of HCl emissions in the Salt Lake Valley, these measurements were conducted in the summer and do not reflect typical wintertime inversion episodes. Transport is inhibited during wintertime cold air pool conditions because surface winds are relatively weak during these periods. Also, The study referenced used only 13 passive samplers at fixed locations in the Salt Lake Valley. HCl concentrations were averaged over two 7-week periods and one 5-day period. Additional measurements are needed to understand the contribution of US Magnesium to HCl emissions and particulate chloride formation. Moreover, the contribution of other sources, such as the Great Salt Lake, road salt and playa dusts from dry salt beds to HCl and particulate chloride is unclear. UDAQ is conducting a field sampling campaign in winter 2018-2019 to better understand the contribution of US Magnesium to chlorine and HCl emissions and its role in ammonium chloride formation. Imposing controls on US magnesium may be premature at this point. **See also Response to Comment A-36.**

Western Resource Advocates

Comment Summary A-25 [submitted by Western Resource Advocates et al.]: From *Section II., Analysis of the Draft Serious SIP: BACM/BACT:*

Comment 1: The Director Must Derive and Implement BACM.

Comment 2: BACT Represents the Maximum Reduction of Emissions Achievable.

Comment 3: BACM is “Generally Independent” of Attainment.

Comment 4: Measures Adopted in Other States Are Assumed to be Technologically Feasible.

Comment 5: BACT Will Be More Expensive than RACT.

UDAQ Response to A-25: UDAQ acknowledges the commenters’ review of the PM_{2.5} Implementation Rule and other pertinent requirements.

Comment Summary A-26 [submitted by Western Resource Advocates et al.]: From *Section III., Specific Comments A: BACT:* The Director failed to derive and implement

1 BACM for the Salt Lake NAA, relying chiefly on regulations and measures adopted as
2 RACM. The Director has not: 1) showed that he has developed and imposed measures
3 for every sector that represent the maximum achievable reductions of emissions; 2)
4 produced a complete review of measures adopted in other states; 3) established why
5 measures adopted in other states are not technologically or economically feasible in Utah;
6 4) applied BACM's "higher economic costs" analysis; and 5) provided objective data to
7 support its contentions.

8
9 Given that the Director's modeling cannot show that the emission reductions required by
10 the SIP are adequate to show attainment, the Director's refusal to adopt control strategies
11 that are demonstrated to be technologically and economically feasible in other states is
12 contrary to the requirements imposed by the Clean Air Act.

13
14 **UDAQ Response to A-26:** UDAQ disagrees with the commenter. In re-reviewing the
15 control measures included as RACM in Utah's Moderate Area PM_{2.5} SIP for the SLC
16 nonattainment area, it was determined that in most cases these measures were in fact
17 already stringent enough so as to also meet BACM. During the development of the
18 moderate area PM_{2.5} SIP, UDAQ was well aware of the potential possibility of eventually
19 being reclassified as a serious nonattainment area. UDAQ was in communication with
20 EPA throughout the development process and had discussed the possibility and potential
21 consequences throughout that development period. During negotiations with the listed
22 sources, UDAQ always made clear to them that they should view potential controls as
23 being "better than RACT" and to "focus on BACT-level controls." UDAQ knew and
24 explained that potentially revisiting this issue with the possibility of replacing "just
25 installed" controls would be an expensive and unpopular undertaking – so better to focus
26 on the higher level of control from the outset. Utah's review of potential controls entails
27 measures that address primary PM_{2.5} and precursors to secondary PM_{2.5}, reveals a
28 canvassing of other states, addresses technological and economic feasibility, concludes
29 that the cost benefit in terms of dollars spent per ton of emissions reduced is consistent
30 with contemporary BACT analyses. This is documented in the materials provided as
31 technical support.

32
33 The commenter's contention that Utah has not included every control measure
34 implemented in any other state is more consistent with the idea of Most Stringent
35 Measures (MSM) than BACM. MSM is not required for the SLC nonattainment area.

36
37 **Comment Summary A-27:** The director has not established whether the contingency
38 measures in the SIP will provide for emissions reductions equivalent to one year's share
39 of reductions needed to demonstrate attainment. In addition, the Director did not state
40 whether the DERA emissions reductions had already been quantified and included in the
41 control strategy for the Salt Lake NAA.

42
43 **UDAQ Response to A-27:** The control strategy analysis summarized in Chapter 5 shows
44 that stationary point sources meet BACT and area sources meet BACM. On-road mobile
45 sources still contribute the majority of emissions, including primary PM_{2.5} and all of the
46 precursors except SO₂. Further emission control in this category extends beyond the

1 authorities of UDAQ. While DERA grants provide a non-regulatory opportunity to
2 reduce emissions for mobile sources, there is currently not enough funding to
3 demonstrate a year's worth of emissions reductions in the Salt Lake NAA with the
4 proposed contingency measures. Control measures developed to meet increasingly
5 stringent ozone and PM_{2.5} standards in Utah's urbanized areas have likewise become
6 increasingly stringent, and still it is a challenge to attain the 2006, PM_{2.5} NAAQS. This
7 leaves little room for additional reductions that can be set aside as contingency measures.

8
9 Requirements of DERA grants include vehicles that are being retired early in order to
10 achieve actual emissions reductions for what would have been the remainder of the
11 vehicle's life. The emissions reductions resulting from DERA vehicles were not
12 accounted for in MOVES calculations for modelling for this SIP. MOVES assumed a
13 typical retirement schedule for all fleets, and did not include early retirement for any of
14 the DERA funded vehicles included in the serious SIP. Therefore, DERA emissions
15 reductions had not already been quantified and included in the control strategy for the
16 Salt Lake NAA. **See also Response to Comment A-7.**

17
18 **Comment Summary A-28 [submitted by Western Resource Advocates et al.]:** *From*
19 *Section III., Specific Comments C: Milestone Requirement:* "Serious area attainment
20 plans must include quantitative milestones that demonstrate RFP towards attainment to
21 be achieved every 3 years until the area is redesignated to attainment." (81 Fed. Reg. at
22 58091). Yet the Director has not complied with this requirement. The first milestones
23 must have been achieved in the Salt Lake NAA by the end of 2017 and the report for the
24 Salt Lake NAA came due in the first quarter of 2018. However, no such report was
25 prepared or submitted to EPA and the Draft Serious SIP makes no effort to comply with
26 this regulatory obligation. As a result, the Director has failed to meet his
27 obligations. Further, the Director is obligated to continue to designate, achieve and report
28 milestones after the attainment date - in this case 2020. Despite this obligation, the
29 Director has not included an additional quantitative milestone to be met beyond the
30 attainment date. Finally, the Directors statement of quantitative milestones is too vague
31 to meet the regulatory requirements.

32
33 **UDAQ Response to A-28:** The commenter is correct that the first quantitative milestone
34 for the SLC nonattainment area was December 31, 2017. The milestone report for 2017
35 was due to EPA not later than 90 days hence. It was submitted to EPA by the Governor
36 on March 23, 2018. EPA subsequently determined that the 2017 quantitative milestone
37 report was adequate, and notified the Governor of such on October 24, 2018.

38
39 The draft Serious Area SIP addresses reasonable further progress (RFP) and quantitative
40 milestones in Chapter 8. Table 8.2 presents emissions of PM_{2.5} and PM_{2.5} precursors for
41 2017 and 2020, identifying each as milestone years.

42
43 UDAQ is proposing revisions to Chapter 8. These revisions are discussed in the response
44 to **Comment A-6.**

1 **Comment Summary A-29:** WRA stated that the **fugitive emissions rule** is not BACM.
2 WRA provided specific reasons:

3 1. WRA challenges the BACM conclusion that there are no current opportunities for
4 additional program revisions that would lead to further emission reductions. WRA
5 further challenges UDAQ assessment that R307-309 is amongst the most stringent
6 rule.

7
8 2) WRA claims that California's South Coast Air Quality Management District fugitive
9 dust rule 403 (403(d)(1XA) and (d)(2)) is more stringent than R307-309 because it
10 prohibits visible dust beyond the property line of the source and requires BACM.

11
12 3) Maricopa County, Arizona prohibits visible dust beyond the property line of the
13 source. Rule 310 at 303.1(a).

14
15 4) Clark County, Nevada prohibits a dust plume that extends 100 yards or more,
16 horizontally or vertically, from the point of origin and requires best available control
17 measures. Rule 94.11.2 and 94.9.3

18
19 5) Washoe County, Nevada prohibits visible fugitive dust emissions lasting more than 5
20 minutes in any hour. Rule 040.030, Section C.

21
22 **UDAQ Response to A-29:** WRA was actually referring to the fugitive dust rule R307-
23 309. The following are responses to the comments above:

24 1. UDAQ conducted its RACM/BACM analysis by reviewing other state rules,
25 referencing the WRAP Fugitive Dust Handbook and using our engineering knowledge.
26 We evaluated every conceivable earth disturbance mechanism that would generate
27 fugitive dust and developed best management practice options for each mechanism in a
28 feasible and cost effective manner. These best management practice options were added
29 to the rule in 2013. Subsequent to this rule revision, UDAQ has received comments from
30 WRA on a number of rulemaking occasions stating that there are more control
31 mechanism are available. We have reviewed those mechanisms and have determined that
32 they are for the most part not feasible, not cost effective or more importantly, would not
33 result in advancing the airshed towards attainment.

34
35 R307-309 applies to all projects ¼ acre and greater where earth is disturbed. Only
36 Maricopa County has a more stringent applicability requirement than R307-309 because
37 it is a moderate PM10 nonattainment area. The winter time PM2.5 contribution from
38 disturbance of frozen earth is low, therefore it is not appropriate to compare the Maricopa
39 County rule or other state rules whose rules are designed to address PM10.

40
41 2) Rule 403 (d)(1)(A) does prohibit visible dust beyond the property line. Again this rule
42 is designed as a PM10 fugitive dust rule and not one to control winter time PM2.5. It is
43 inappropriate to blindly say that this or any other PM10 rule can be directly compared to
44 a winter time PM2.5 fugitive dust emission.

1 3) Maricopa County Rule 303 is designed for a moderate PM10 nonattainment area. It is
2 inappropriate to compare every facet of Rule 303 to R307-309. In this case, WRA has not
3 also stated in their comment that Rule 303 provides the option of either no visible dust
4 beyond the property boundary OR 20% opacity. R307-309 requires an opacity of 10% at
5 the property boundary.

6
7 4) Clark County is a serious PM10 nonattainment area. It is inappropriate to compare a
8 rule designed for a serious PM10 nonattainment to a winter time PM2.5 fugitive dust
9 rule.

10
11 5) Washoe County Rule 040.030, Section C applies to dust generating activities of 1 acre
12 and greater which is less stringent than R307-309's ¼ acre. Clark County, Nevada dust
13 generating prohibitions are designed for their serious PM10 nonattainment status.

14
15 WRA has not substantiated their positions quantitative evidence that their
16 recommendations would move the attainment needle forwards nor provided a cost-benefit
17 analysis. Meanwhile, UDAQ has determined that R307-309 provides a control efficiency
18 of 32% at a cost of \$2,140/acre (Area Source TSD) which has not been challenged by
19 EPA to date. The 32% is based on an annual emission when the actual control efficiency
20 for this SIP is greater due to winter ground freezing conditions.

21
22 In summary, it is important to note that it is the responsibility of EPA to make BACM
23 determinations for each specific nonattainment area which reinforces our position that
24 examples noted in WRA's comments are not necessarily BACM for the Salt Lake winter
25 time PM2.5 nonattainment area.

26
27 **Comment Summary A-30:** The Director failed to consider building codes as BACM.

28
29 **UDAQ Response to A-30:** The Utah Air Quality Board does not have authority to
30 regulate State building codes. Instead, Utah's building codes are reviewed by the
31 Uniform Building Code Commission and recommendations are made to the Utah State
32 Legislature for consideration and final adoption. The building codes that have been
33 adopted for Utah are located in the State Construction Code Administration and Adoption
34 of Approved State Construction Code Rule, UAC R156-15A, and approved codes that
35 may also be adopted by local compliance agencies are located in the State Construction
36 and Fire Codes Act, Utah Code Ann., Title 15A. Emissions reductions associated with
37 existing building codes as well as those stemming from electric and gas utility energy
38 efficiency programs are already incorporated into the SIP emissions inventory.

39
40 **Comment Summary A-31:** The Director did not consider California's more stringent
41 regulation of non-road mobile sources.

42
43 **UDAQ Response to A-31:** UDAQ agrees with the commenters that it did not mention or
44 analyze California's Nonroad Rule in the Salt Lake BACM analysis because Utah cannot
45 adopt the rule under the provisions of the Clean Air Act (CAA) as outlined below.

1
2 Nonroad engines and vehicles are regulated at the federal level through several rules as
3 outlined in the Salt Lake BACM analysis. States other than California are preempted
4 from establishing standards for nonroad engines and equipment under CAA Section
5 209(e). While states may, as allowed under CAA Section 209(e)(2)(B), adopt California
6 in-use regulations for nonroad engines and vehicles that have been authorized by EPA
7 under CAA Section 209(e)(2)(A), UDAQ concluded that Utah could not adopt such
8 standards for two key reasons. First, CAA Section 209(e)(2)(B)(i) requires the adoption
9 of standards that "... are identical, for the period concerned, to the California standards
10 authorized by the Administrator..." Second, CAA Section 209(e)(2)(B)(ii) requires that
11 states "... adopt such standards at least 2 years before commencement of the period for
12 which the standards take effect." Because several of the key California nonroad in-use
13 regulatory deadlines have already passed, Utah cannot adopt identical standards and have
14 them be technically feasible, and it did not historically adopt such standards 2 years
15 before commencement of the period for which the standards take effect.

16
17 **Comment Summary A-32:** The Director did not adequately consider California's more
18 stringent regulation of on-road mobile sources.

19
20 **UDAQ Response to A-32:** UDAQ did not include California's on-road regulations in
21 the Salt Lake BACM analysis because Utah cannot adopt the rule under the provisions of
22 the Clean Air Act (CAA) and because the California regulations are not expected to result
23 in additional emissions reductions beyond those provided by the federal Tier 3 program
24 as outlined below.

25
26 Onroad vehicles and engines are regulated at the federal level through several rules as
27 outlined in the Salt Lake BACM analysis. Examples include the EPA Tier 3 vehicle
28 standards and the EPA Emissions Standards for Heavy-duty Highway Vehicles and
29 Engines. States other than California are preempted from establishing standards for new
30 motor vehicles or new motor vehicle engines under CAA Section 209(a). While states
31 may, as allowed under CAA Section 177, adopt California emissions standards for which
32 a waiver has been granted under CAA Section 209(b)(1), UDAQ concluded that Utah
33 could not adopt such standards for model years prior to the SIP attainment date since
34 CAA Section 177 requires that states "... adopt such standards at least two years before
35 commencement of such model year..."

36
37 Even if the adoption of such standards were allowed under CAA Section 177, it should be
38 noted that EPA's Tier 3 standards were based on the California's LEV III standards and
39 include the same emissions control levels required by LEV III through 2024.
40 Furthermore, due to the fleet averaging provisions of both Tier 3 and LEV III, it is
41 unlikely that the adoption of the California ZEV program alongside either standard (Tier
42 3 or LEV III) would result in lower fleet-wide emissions levels, since each additional
43 vehicle introduced into the fleet under the ZEV program would only serve to increase the
44 number of higher-emitting vehicles allowed in the total vehicle fleet while meeting the
45 fleet-wide averaging requirement.

1 **Comment Summary A-33:** WRA believes that more public awareness should be
2 directed towards the education of wood burning hazards.

3
4 **UDAQ Response to A-33:** UDAQ has partnered with UCAIR to perform public
5 education. UCAIR spent half a million dollars in their last years wood burning and
6 clean air campaign. This is not an insignificant amount of money which must be allocated
7 by the Legislature.
8

9 **Comment Summary A-34:** WRA states that it is unclear whether the current level at
10 which mandatory burn bans are instituted, 25 ug/m³, is as strict as necessary to qualify as
11 BACM. San Joaquin Air Quality Management District has set its burn ban limit at 20
12 ug/m³ in its moderate PM_{2.5} SIP (Rule 4901.5.6.), and is considering a stricter limit for
13 its serious PM_{2.5} SIP.
14

15 **UDAQ Response to A-34:** Please refer to the **Response to Comment A-23**.
16

17 **Comment Summary A-35: [submitted by Western Resource Advocates et al.]:** *From*
18 *Section III., Specific Comments I: No near-road PM_{2.5} monitor:* Utah was required to
19 have an operational PM_{2.5} near-road monitor in the Salt Lake NAA by January 1,
20 2017. EPA has explained that "When complete data from near-road PM_{2.5} ambient
21 monitors become available, the data should be used by states and the EPA for all aspects
22 of the NAAQS implementation process, from attainment planning to the determination of
23 attainment." (81 Fed. Reg. at 58138). Had Utah followed the law, its near road PM_{2.5}
24 monitor would have had the requisite three years of data as of December 2019. Without
25 an operational monitor, Utah cannot show attainment. The Air Quality Board should
26 demand that Director install the required monitor, and the possible determination that the
27 Salt Lake NAA has attained the PM_{2.5} standard must be suspended until Utah can show
28 that the standard is being met at a near road monitor.
29

30 **UDAQ Response to A-35:** 40 CFR Part 58 Appendix D 4.7.1(b)(2) requires that, for a
31 Core Based Statistical Area with a population of 1,000,000 or more persons, at least one
32 PM_{2.5} monitor is to be collocated at a near-road NO₂ station. The commenter is correct
33 that such monitor was to be in place on Jan 1, 2017, and had this been the case would
34 likely have collected a full 3-year data set by the attainment date of December 31, 2019.
35

36 EPA will be obligated to determine whether the SLC nonattainment area has or has not
37 attained the NAAQS at that time. The Near-Road monitor will become operational on
38 Jan 1, 2019, as per a schedule agreed upon by UDAQ and EPA.
39
40

41 **Comment Summary A-36 [submitted by Western Resource Advocates et al.]:** *From*
42 *Section III., Specific Comments J: U.S. Magnesium:* The draft SIP notes that "Both
43 hydrochloric acid (HCl) and aerosol chloride play an important role in PM_{2.5} formation."
44 and that "[m]easured HCl is also underestimated by the model, particularly in the vicinity

1 of US Magnesium, where values as high as 100 ppb were observed during the 2017
2 UWFPS."

3
4 In addition UPA's comment presents a weight-of-evidence analysis that clearly identifies
5 ammonium chloride as a significant contributor to PM_{2.5} concentrations in the SLC
6 Nonattainment Area, and indicates that "US Magnesium Corporation is the single
7 culpable source."

8
9 These findings establish that the Director must consider applying additional controls or
10 undertaking better enforcement of HCl emissions at U.S. Magnesium. "[a] state has
11 discretion to require reductions from any source inside or outside of a PM_{2.5}
12 nonattainment area (but within the state's boundaries) in order to fulfill its obligation to
13 demonstrate attainment in a PM_{2.5} nonattainment area as expeditiously as
14 practicable[.]" 81 Fed. Reg. at 58080.

15
16 Because further controls on US Magnesium will reduce ammonium chloride and PM_{2.5} in
17 Salt Lake City and could be a key to attaining the PM_{2.5} NAAQS, the Air Quality Board
18 should ask the Director to consider and implement effective and appropriate measures to
19 reduce US Magnesium emissions and better enforcement of existing controls.

20
21 **UDAQ Response to A-36:** UDAQ acknowledges that the Implementation Rule provides
22 authority and direction to control emissions from sources located outside the NAA (but
23 within the state) if necessary to provide for attainment by the attainment date. This
24 authority also extends to PM_{2.5} plan precursors (those precursors required to be regulated
25 in the applicable attainment plan and/or the NNSR program).

26
27 Nevertheless, the applicable attainment plan already demonstrates attainment of the
28 standard by the attainment date. Therefore it is not necessary to extend control beyond
29 the boundary of the nonattainment area.

30
31 UDAQ remains interested in pursuing some of the questions raised by the Wintertime
32 Fine Particulate Study. Among these questions is the attribution of ammonium chloride
33 from U.S. Magnesium. However, it is not compelled by rule to include U.S. Magnesium
34 in the SIP at this time. **See also Response to Comment A-24.**

35
36 **Comment Summary A-37:** Only air agencies may submit a precursor demonstration. In
37 addition, a public comment period must be granted for a precursor demonstration.

38
39 **UDAQ Response to A-37:** UDAQ agrees that if Utah elected to submit to the EPA one
40 or more precursor demonstrations for the SL NAA, the EPA would be compelled to
41 review and act upon the submittal. UDAQ also agrees that if a precursor demonstration
42 were submitted by the State to the EPA, the demonstration would be subject to public
43 review and comment.

44
45 **Comment Summary A-38:** UPA's claim that major source precursor emissions do not
46 contribute significantly is wholly dependent on a threshold concentration, despite that it

1 fails to address the particular circumstances of the Salt Lake NAA, that EPA has rejected
2 the notion of any bright line threshold, and that it is based on the 2018 Technical Basis
3 Document that is not relevant to precursor demonstrations and EPA draft guidance that
4 the agency refers to as recommendations and guidelines.
5

6 **UDAQ Response to A-38:** The Draft PM2.5 Precursor Demonstration Guidance was
7 released for public comment on November 17, 2016. There is no final guidance published
8 to date. The recommended significance threshold in the draft guidance is 1.3 ug/m3 and
9 the UPA precursor demonstration used a significance threshold of 1.5 ug/m3. However,
10 the guidance also states “under the PM2.5 SIP Requirements Rule, the significance of a
11 precursor’s contribution is to be determined based on the facts and circumstances of the
12 area”. UDAQ supports using the best guidance available. **See also Responses to**
13 **Comments A-3, comment #4, and A-16.**
14

15 **Comment Summary A-39:** UPA is wrong to suggest that its modeling exercise compels
16 any particular action. UPA’s modeling can do nothing more than purport to estimate the
17 contribution that precursor emissions from major sources have on the Salt Lake NAA, it
18 does not establish that these contributions are insignificant. The UPA modeling serves
19 only to estimate contributions and does not compel either the AQB or the Division to do
20 anything other than consider what the trade group has put forward. UDAQ has the
21 discretion to represent to the AQB that BACT must be imposed for all precursor
22 emissions and the appropriate course of action for the AQB is to ensure that UDAQ
23 imposes BACT on the Salt Lake NAA major sources.
24

25 **UDAQ Response to A-39:** UDAQ acknowledges the effort UPA put into their precursor
26 demonstration based on the available draft guidance. If the State were to submit a
27 precursor demonstration to EPA with AQB approval, it would be based on UDAQ’s own
28 work and modeling.
29

30 **Comment Summary A-40:** The UPA submission conflicts with the proposed Salt Lake
31 NAA Serious SIP. It is contrary to the Division's position articulated in their Draft
32 Serious SIP. Because UPA's prediction of precursor contribution has no persuasive power
33 in light of the Division's findings and analysis, it should be rejected.
34

35 **UDAQ Response to A-40:** The UDAQ is not electing to submit a major stationary
36 source precursor demonstration at this time.
37

38 **Comment Summary A-41:** A precursor demonstration could not be submitted to EPA
39 unless the Serious SIP and BACT review were radically rewritten and the public given
40 the opportunity to comment on this fundamental change in the Utah's strategy for
41 bringing the Salt Lake NAA into compliance with the PM2.5 NAAQS.
42

1 **UDAQ Response to A-41:** The UDAQ is not electing to submit a major stationary
2 source precursor demonstration at this time. Therefore Part A and Part H do not need to
3 be rewritten or opened for public comment again.
4

5 **Comment Summary A-42:** A Division precursor demonstration could not withstand
6 review. The Division has consistently maintained a position that is antithetical to the
7 position put forth by UPA. For the Division to suddenly flip its position relative to these
8 determinations and to contend that its uncertain model could show that precursors from
9 major sources do not significantly contribute to PM2.5 concentrations would necessarily
10 be arbitrary and capricious and could not withstand scrutiny.
11

12 **UDAQ Response to A-42:** The UDAQ is not electing to submit a major stationary
13 source precursor demonstration at this time.
14

15 **Comment Summary A-43:** UPA modeling fails to reject the aggregate impact of
16 precursor emissions from major sources in the Salt Lake NAA.
17

18 **UDAQ Response to A-43:** EPA's draft guidance is silent on the aggregation of impacts
19 from two or more precursor demonstrations. However, the PM2.5 Implementation Rule
20 does emphasize that significance is to be determined based on the "*facts and*
21 *circumstances of the area*". UDAQ performed its own analysis, and therein did evaluate
22 aggregate impacts. For more discussion thereof, see **Response to Comment A-16**.
23

24 **Comments from individual citizens**

25

26 **Comment Summary A-44:** UDAQ received a number of **comments from individual**
27 **citizens**. These comments fell into four categories: 1) outside of DAQ's regulatory
28 authority, 2) within DAQ's regulatory authority and were addressed through BACM
29 analysis with this SIP, 3) general comments on the state of Utah's air quality that did not
30 contain addressable content, and 4) comments that UDAQ addresses through grant
31 programs.
32

33 *Comment summary of comments that fall outside of DAQ's regulatory authority:* add
34 trax/frontrunner instead of expanding roads and highways, tax incentives for
35 telecommuting, no new permits for commercial entities, ensure citizen's snowblowers
36 and lawnmowers are properly maintained, incentivize green energy, less expensive public
37 transportation (possibly by increasing taxes), ban idling, no mining on windy days, all
38 vehicles tier III, inland port zero carbon, no gravel pit expansion, no draining Utah Basin
39 aquifers, increase gas tax, institute carbon tax, encourage telecommuting on red air days,
40 UTA free in winter months and/or on red air days, tougher emissions standards for diesel
41 trucks (particularly coal rolling), heavy duty diesel emissions program, use lower NOx
42 fuels, improve emissions testing for all of Utah, stop burning fields, reduce dust
43 pollution, ban fireworks, no coal burning for heat, incentivize carpooling, idling
44 education, reduce fertilization and food waste, require state employees to telecommute

1 when possible, regulate industrial vehicles, Kennecott could have a voluntary clean
2 cessation of activities during inversions, subsidize low income to improve insulation and
3 heating, air quality education for Traeger grill owners, ban 2-cycle yard equipment in
4 Utah, and require local refineries to meet 10ppm sulfur standard.

5
6 **Comment Response:** While many of these comments may help improve Utah's air
7 quality, they are not within UDAQ's ability to regulate. Many of these comments would
8 require a state or federal legislative action. Some of the comments are controlled by State
9 and local agencies other than UDEQ.

10
11 *Comments that UDAQ addresses through grant programs, but not through this SIP:*

12
13 **Comment:** Incentivize EV

14 **Response:** UDAQ has administered a few programs over the years with funding provided
15 by the legislature that incentivize clean fuels, including EV. In addition, UDAQ is
16 allocating approximately 3.8 million of the Volkswagen settlement for light duty electric
17 vehicle charging infrastructure.

18
19 **Comment:** Promote electric yard equipment

20 **Response:** UDAQ and partners held a snowblower exchange this fall and will be holding
21 a lawnmower exchange next spring. UDAQ will continue these exchange programs as
22 long as there is funding available.

23
24 **Comment:** Assist wood heating to gas change out

25 **Response:** UDEQ is currently administering a \$3 million dollar grant from the EPA to
26 convert wood heating to natural gas in the Salt Lake NAA.

27
28 *Comment summary on comments that have been addressed through the SIP process:*

29 Regulate industry and refineries, do what CA has done, no wood burning, enforcement
30 for burning on no-burn days, increase monitoring locations, and there should not be any
31 exemptions on flare gas recovery.

32
33 **Response:** These comments were addressed through this SIP. The SIP process requires
34 both stationary point sources (large refineries and industry) and area sources (residences,
35 businesses, small industry) to implement the best available control measure (BACM) to
36 control emissions. Part of the BACM analysis is reviewing what other nonattainment
37 areas in the U.S. have implemented. BACM includes new or amended rules to address
38 both point and area sources, including everything from specific controls on refineries to
39 wood burning rules. In regards to monitoring locations, UDEQ meets monitoring
40 requirements set by the EPA.

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ATTACHMENT C

1 Draft UDAQ Major Stationary Source
2 Precursor Demonstration for the Salt
3 Lake City 24-hour PM_{2.5} Serious non-
4 attainment Area

5
6 [Utah Division of Air Quality](#)

7

8

9

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1.0 Introduction

The Utah Division of Air Quality (UDAQ) seeks to find the most beneficial impacts to air quality, while minimizing the economic burden for stakeholders. When considering new emissions control requirements, it is important to not only consider the environmental benefit, but also the associated cost. For major stationary sources, the cost of implementing new emissions controls can be particularly high.

Due to the nonlinear nature of air chemistry along with the Salt Lake Valley's unique geography, a photochemical model is needed to assess wintertime PM_{2.5} pollution impacts from gaseous emissions. UDAQ conducted precursor demonstrations using photochemical modeling to quantify the air quality impacts from NO_x, SO_x, VOC, and NH₃ emissions due to major stationary source operations in the Salt Lake City (SLC) non-attainment area.

2.0 Modeling Framework

In conducting the precursor demonstrations presented in this document, UDAQ used the same CAMx 6.30 modeling framework used in their Serious SLC PM_{2.5} modeled attainment demonstration. Details relating to CAMx setup/parameterization, emissions inventory development, and meteorological modeling can be found in the Technical Support Documentation (TSD) that accompanies the State implementation Plan (SIP).

UDAQ used the 2019 emissions inventory (EI) developed for the SLC non-attainment area PM_{2.5} SIP, with one notable exception: For the precursor demonstrations presented in this document, the large haul trucks at the Kennecott Utah Copper (KUC) Bingham Canyon Mine were processed as non-road mobile source emissions, instead of treating them as part of the major stationary source inventory.

UDAQ used meteorological model (WRF-ARW version 3.7) output from their Serious PM_{2.5} SIP modeled attainment demonstration. The modeled meteorological episode is a 10-day persistent cold-pool event, spanning January 1 - January 11, 2011. The WRF-ARW model generally performed well. The cold-pool evolution and vertical thermal structure were well simulated, enabling UDAQ to model the high PM_{2.5} concentrations observed in the Salt Lake Valley during this period.

3.0 Major Stationary Sources Precursor Demonstrations

For the precursor demonstrations presented here, UDAQ examined the change in modeled PM_{2.5} due to eliminating different permutations of gas precursor emissions from the 2019 Salt Lake City non-attainment major stationary sources inventory. Five different precursor demonstrations were created by completely removing emissions of:

- 1) NO_x
- 2) SO_x
- 3) VOC
- 4) NH_3
- 5) all four gas precursors: NO_x , SO_x , VOC, and NH_3

Only emissions from SLC non-attainment area major stationary sources were removed. Essentially, a precursor demonstration entails calculating the change (or difference) in modeled 24-hour $\text{PM}_{2.5}$ due to the precursor(s) being eliminated in a particular scenario.

If modeled $\text{PM}_{2.5}$ differences between the 2019 SIP scenario and emissions reduction scenario were greater than $1.5 \mu\text{g}/\text{m}^3$, then these differences were considered “significant”. This threshold of $1.5 \mu\text{g}/\text{m}^3$ is provided in a recent update to the “Technical Basis Document” that underlies draft Precursor Demonstration guidance currently under EPA review.

Figure 3.0.1, below, shows modeled 24-hour $\text{PM}_{2.5}$ results for the wintertime episode used in UDAQ’s modeled attainment test for the Serious SLC non-attainment SIP. The meteorological episode spans from January 1 - 10, 2011. The precursor demonstrations use the 2019 EI that was used in Utah’s Serious SLC non-attainment area SIP, with one notable exception: As noted above, the emissions from large haul KUC mining trucks were removed from the major stationary source (i.e., point) category. Instead, KUC mining truck emissions were added to the non-road mobile sector. Several figures in this document highlight results for the 7th day (January 7) of the episode, since the largest $\text{PM}_{2.5}$ concentrations were modeled on this day (see Figure 3.0.1).

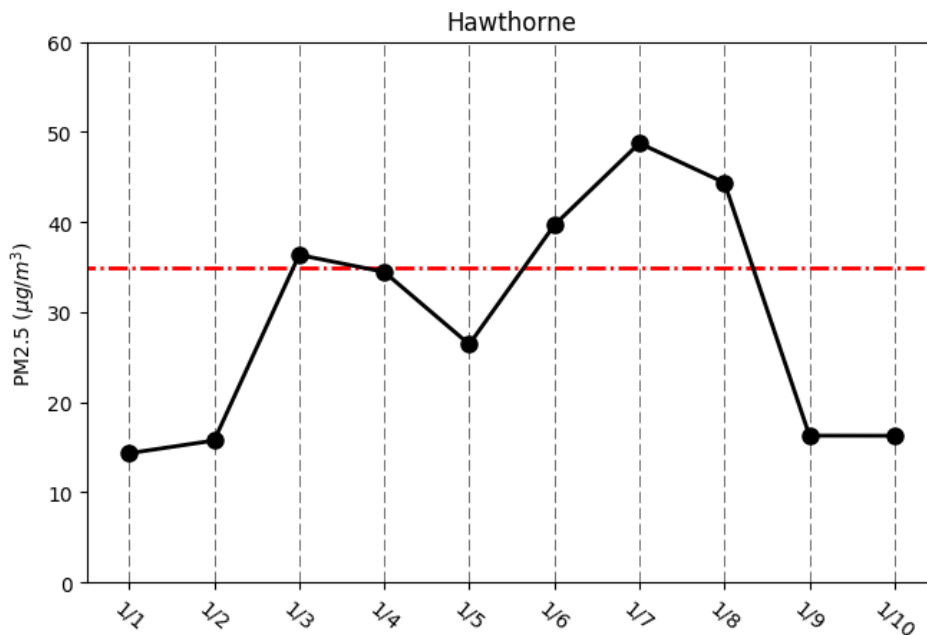
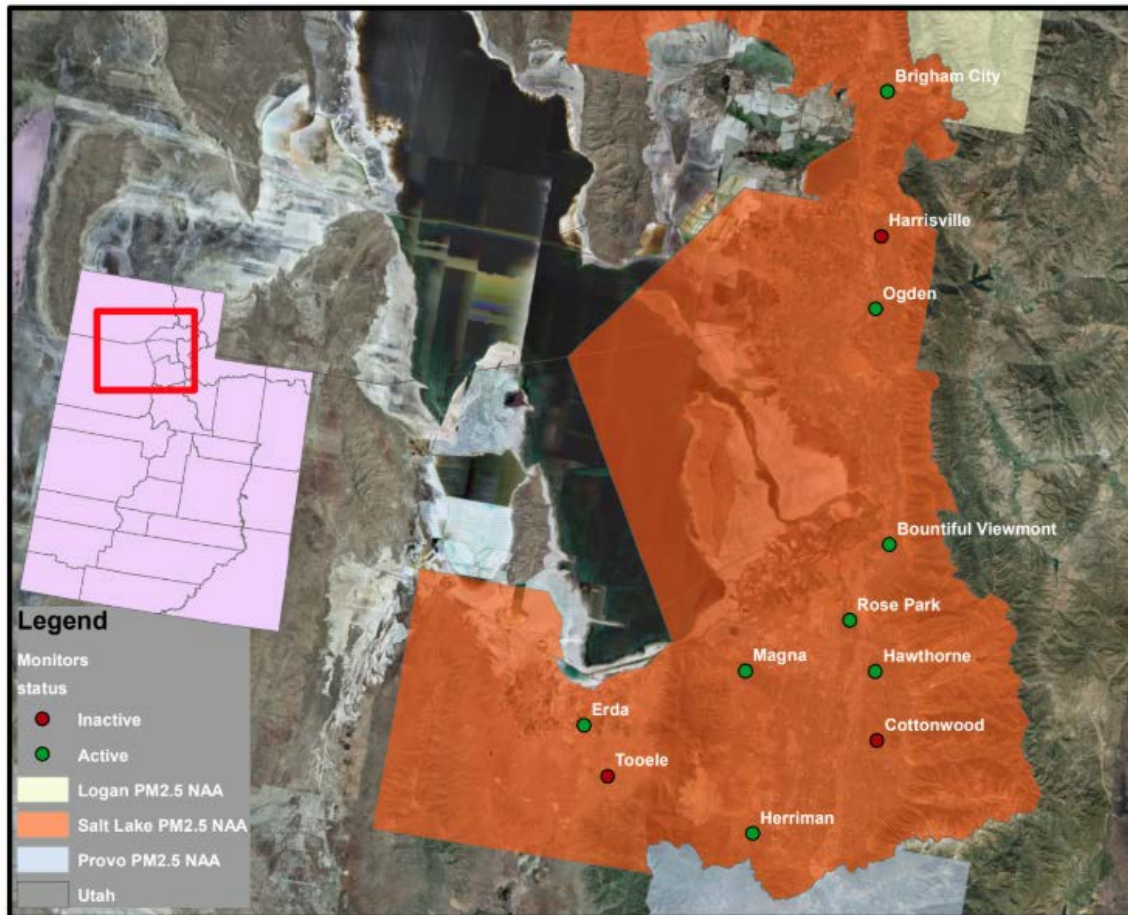


Figure 3.0.1: Plot of modeled 24-hour $\text{PM}_{2.5}$ at Hawthorne (Salt Lake City) using 2019 emissions inventory for January 1-10, 2011 meteorological episode. Red dashed

1 line indicates the National Ambient Air Quality Standard (NAAQS) for daily PM_{2.5}
2 (35 µg/m³).
3
4

5 The precursor demonstrations UDAQ conducted evaluate changes in modeled PM_{2.5} at
6 SLC non-attainment area monitors. Figure 3.0.2, below, shows the locations of PM_{2.5}
7 FRM monitors in the SLC non-attainment area. The highest modeled PM_{2.5} occurred at
8 the Hawthorne monitor, near downtown Salt Lake City. UDAQ will also present results
9 across the entire non-attainment area on January 7, when the largest changes in modeled
10 PM_{2.5} generally occurred.
11



12
13 **Figure 3.0.2: Detail of northern Utah. The Salt Lake City (SLC) non-attainment**
14 **area is depicted by orange overlay. PM_{2.5} FRM monitor locations are shown by dots**
15 **in the map. Green dots represent currently active PM_{2.5} monitors. Red dots indicate**
16 **monitors no longer in operation.**
17

18 3.1 Precursor Demonstration for NO_x

19 Removing major stationary source NO_x emissions produced changes in modeled in PM_{2.5}
20 less than 1.5 µg/m³ at all monitors during the length of the episode. However, model

results revealed a NO_x disbenefit effect at some monitor locations. A NO_x disbenefit occurs in NO_x-saturated environments where the more frequent conversion of NO to NO₂ suppresses the oxidation of NO₂ to particulate nitrate (NO₃). By reducing NO_x in this kind of environment, PM_{2.5} concentrations can actually increase. Although counterintuitive, a NO_x disbenefit can occur in physical reality. These NO_x disbenefit effects are indicated by negative values shown below in Table 3.1.1. Negative changes in PM_{2.5} make it difficult to interpret the air quality impacts from major stationary sources. For this reason, UDAQ also conducted supplemental source apportionment modeling to estimate the contribution of major stationary sources to particulate nitrate (NO₃) formation (see section 4.0).

2019 base case - 2019 NO _x control case	Change in PM _{2.5} (ug/m3)									
	2011001	2011002	2011003	2011004	2011005	2011006	2011007	2011008	2011009	2011010
Herriman	0.00	0.00	0.05	0.24	0.02	0.01	0.01	0.16	0.07	0.04
Tooele	0.00	0.02	0.18	0.27	0.03	0.12	0.28	0.33	0.04	0.02
Cottonwood	0.01	0.01	0.16	0.33	0.04	-0.11	-0.37	0.00	0.17	0.07
Erda	0.00	0.03	0.43	0.30	0.06	0.18	0.53	0.49	0.02	0.04
Hawthorne	0.01	-0.01	0.15	0.39	0.04	-0.16	-0.53	0.07	0.15	0.07
Magna	0.00	0.05	0.44	0.48	0.14	0.12	0.47	0.26	0.07	0.10
Rose Park	0.01	0.03	0.47	0.43	0.03	-0.28	0.17	0.25	0.18	0.08
Bountiful Viewmont	0.02	0.04	0.34	0.70	-0.16	-1.58	0.12	0.60	0.13	0.18
Ogden	0.03	0.04	0.22	0.52	0.21	0.23	0.82	0.61	0.11	0.16
Harrisville	0.04	0.09	0.13	0.45	0.21	0.64	0.79	0.66	0.06	0.11
Brigham City	0.27	0.23	0.21	0.45	0.33	0.98	1.20	0.96	0.05	0.23

Table 3.1.1: Change in modeled 24-hour PM_{2.5} due to eliminating all NO_x emissions from major stationary sources in the 2019 Serious PM_{2.5} SLC non-attainment area EI. Each row represents results at a specific SLC non-attainment area monitor. Each column represents one day in a 10-day modeled wintertime episode (starting with January 1).

It should be noted that monitors correlated with negative changes in PM_{2.5} were located in north Salt Lake County and south Davis County. The recent 2017 Utah Wintertime Fine Particulate Study (UWFPS) report¹ suggests that the environment in northern Salt Lake County is uniquely NO_x-rich relative to other regions of the Wasatch Front and Cache Valley. However, it is not completely clear if the model has been parameterized well enough to accurately portray the relationship between NO_x and key oxidants (e.g., O₃ and N₂O₅) in the region. Figure 3.1.1, below, shows that the largest negative change in PM_{2.5} occurred in the north Salt Lake County region. When looking at the entire spatial field (1.3 km CAMx modeling domain), changes in nitrate (NO₃) exceeding 1.5 µg/m³ may be seen in a broad area north of the Brigham City monitor in Box Elder County (Figure 3.1.1 panel b). Therefore, significant (positive) changes in PM_{2.5} also occurred in the non-attainment area.

¹ <https://deq.utah.gov/air-quality/utah-winter-fine-particulate-study-uwfps>

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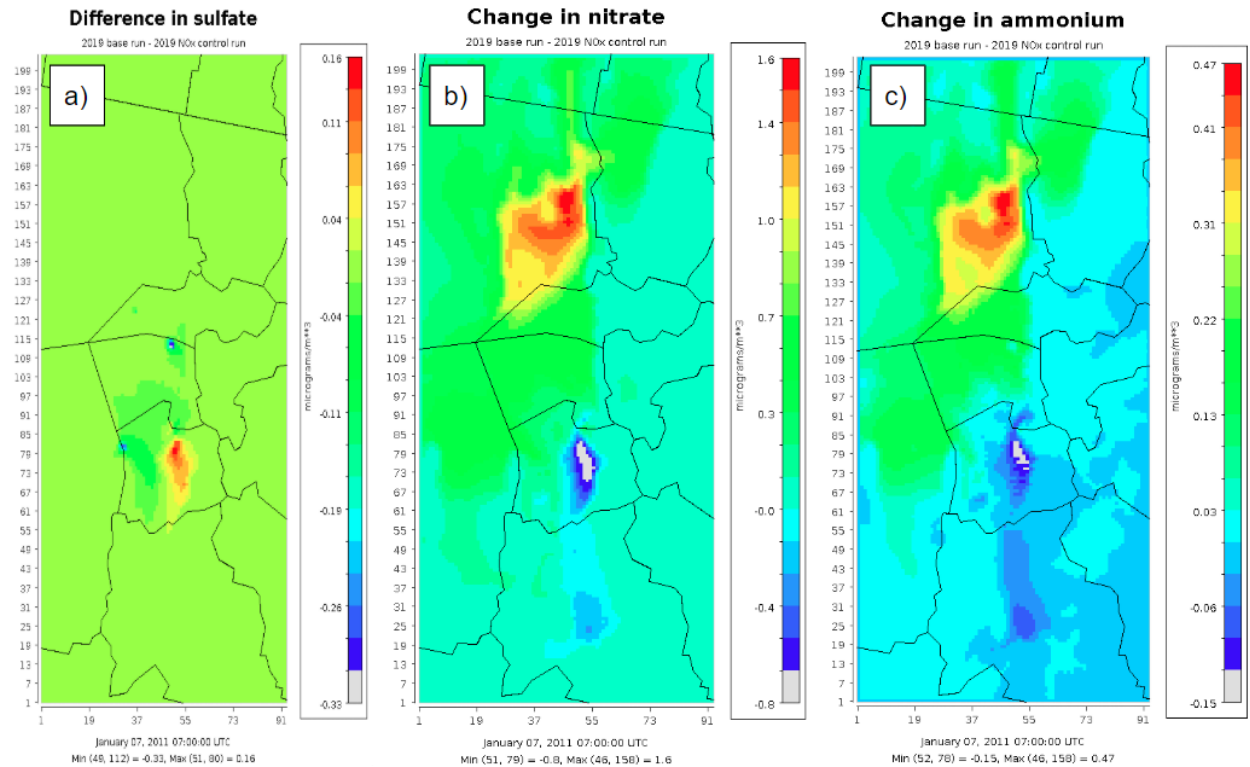


Figure 3.1.1: Changes in modeled 24-hour PM_{2.5} species (a-sulfate, b-nitrate, c-ammonium) due to eliminating NO_x emissions from major stationary sources.

Using 2011 ambient 24-hour PM_{2.5} FRM data that coincides with the modeled episode, UDAQ attempted to correct model biases by scaling (absolute) changes in PM_{2.5} by the ratio of monitored PM_{2.5} over modeled (full 2019 EI) PM_{2.5}. Unfortunately, PM_{2.5} monitor data was not available for all days and monitors; this is reflected by the blank values in the cells of Table 3.1.2, below. After correcting for model bias, results indicated a significant change in PM_{2.5} at the Ogden monitor on January 7.

2019 base case - 2019 NOx control case	Change in PM _{2.5} measured (ug/m ³)									
	2011001	2011002	2011003	2011004	2011005	2011006	2011007	2011008	2011009	2011010
Herriman										
Tooele			0.23			0.15			0.05	
Cottonwood	0.01	0.02	0.18	0.53	0.08	-0.17	-0.47	0.00	0.31	0.08
Erda										
Hawthorne	0.01	-0.01	0.13	0.58	0.07	-0.23	-0.72	0.11	0.24	0.06
Magna			0.60			0.21			0.13	
Rose Park	0.01	0.06	0.44							0.09
Bountiful Viewmont			0.27			-1.86			0.21	
Ogden			0.32	0.68	0.37	0.31	1.54	1.01	0.24	0.12
Harrisville				0.86		1.24			0.23	
Brigham City			0.21			1.50			0.19	

Table 3.1.2: Bias-corrected change in modeled 24-hour PM_{2.5} due to eliminating NOx emissions from major stationary sources. Monitor Data was not available for every site and day, as noted by blank cells. Changes in PM_{2.5} greater than 1.5 µg/m³ are highlighted in red.

3.2 Precursor Demonstration for SO_x

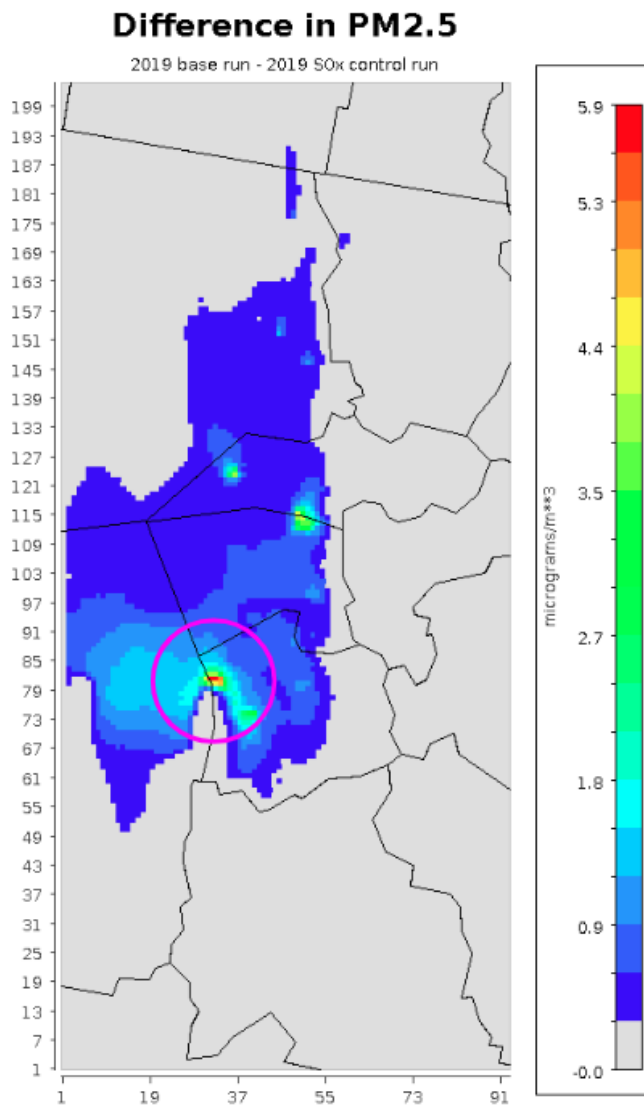
Generally larger values of PM_{2.5} changes due to SO_x are expected due to the the relatively large contribution of SO_x (roughly 79%) from major stationary source emissions. Looking at Table 3.2.1, below, most monitors did not show a significant impact from major source SO_x reductions. However, the change in modeled PM_{2.5} at the magna monitor was significant (1.91 µg/m³) on January 7.

2019 base case - 2019 SOx control case	Change in PM _{2.5} (ug/m ³)									
	2011001	2011002	2011003	2011004	2011005	2011006	2011007	2011008	2011009	2011010
Herriman	0.00	0.00	0.19	0.33	0.02	0.01	0.35	0.19	0.50	0.09
Tooele	0.00	0.01	0.24	0.42	0.03	0.36	0.67	0.62	0.10	0.04
Cottonwood	0.01	0.03	0.60	0.75	0.06	0.09	0.56	0.16	0.27	0.14
Erda	0.00	0.00	0.16	0.33	0.08	0.22	1.08	1.02	0.03	0.07
Hawthorne	0.01	0.06	0.64	0.98	0.07	0.17	0.93	0.25	0.22	0.15
Magna	0.00	0.00	0.10	1.13	0.15	0.35	1.91	1.40	0.30	0.56
Rose Park	0.01	0.00	0.65	0.93	0.06	0.21	0.79	0.39	0.17	0.16
Bountiful Viewmont	0.01	0.01	1.48	0.90	0.59	0.79	0.53	0.57	0.22	0.19
Ogden	0.01	0.01	0.10	0.55	0.28	0.56	0.67	0.57	0.10	0.20
Harrisville	0.02	0.02	0.07	0.32	0.19	0.27	0.51	0.47	0.10	0.16
Brigham City	0.03	0.03	0.08	0.18	0.24	0.32	0.50	0.54	0.04	0.16

Table 3.2.1: Change in modeled 24-hour PM_{2.5} due to eliminating SOx emissions from major stationary sources in the 2019 Serious PM_{2.5} SLC non-attainment area EI. Each row represents results at a specific SLC non-attainment area monitor. Each column represents one day in the modeled 10-day wintertime episode, starting on January 1. Significant changes in modeled PM_{2.5} are highlighted in red.

When we consider SLC non-attainment area as whole, analysis showed a maximum change in PM_{2.5} of 5.9 µg/m³ in western Salt Lake County (Figure 3.2.1, below).

1 Localized changes in modeled PM_{2.5} greater than 1.5 µg/m³ were also observed in Weber
2 County and Box Elder County.
3
4



5
6 **Figure 3.2.1: Change in modeled 24-hour PM_{2.5} due to eliminating all SO_x emissions**
7 **from major stationary sources in the SLC non-attainment area EI. The largest**
8 **change in modeled PM_{2.5} (5.9 µg/m³) was observed in western Salt Lake County**
9 **(purple circle).**

10
11
12 After correcting for model bias, there were no changes in PM_{2.5} greater than 1.5 µg/m³ at
13 monitor locations (Table 3.2.2, below). However, there were no available PM_{2.5} records
14 at Magna on January 7, when simulated PM_{2.5} concentrations were highest.
15
16

2019 base case - 2019 SO _x control case	Change in PM _{2.5} measured (ug/m ³)									
	2011001	2011002	2011003	2011004	2011005	2011006	2011007	2011008	2011009	2011010
Herriman										
Tooele			0.31			0.46			0.11	
Cottonwood	0.01	0.05	0.68	1.18	0.13	0.14	0.73	0.28	0.48	0.17
Erda										
Hawthorne	0.01	0.07	0.57	1.45	0.13	0.24	1.24	0.38	0.34	0.13
Magna			0.14			0.61			0.53	
Rose Park	0.01	0.01	0.61							0.20
Bountiful Viewmont			1.16			0.93			0.35	
Ogden			0.15	0.72	0.50	0.75	1.25	0.94	0.21	0.15
Harrisville				0.61		0.52			0.38	
Brigham City			0.08			0.50			0.15	

Table 3.2.2: Bias-corrected change in modeled 24-hour PM_{2.5} due to eliminating SO_x emissions from major stationary sources. Monitor Data was not available for every site and day, as noted by blank cells.

3.3 Precursor Demonstration for VOC

Changes in modeled PM_{2.5} due to eliminating major source VOC emissions were less than significant at all monitors during the episode (Table 3.3.1, below). The largest change was only 0.61 µg/m³, which was produced at the Bountiful Viewmont monitor on January 6.

2019 base case - 2019 VOC control case	Change in PM _{2.5} (ug/m ³)									
	2011001	2011002	2011003	2011004	2011005	2011006	2011007	2011008	2011009	2011010
Herriman	0.00	0.00	0.04	0.02	0.00	0.01	0.21	0.07	0.01	0.00
Tooele	0.00	0.00	0.02	0.00	0.00	0.02	0.02	0.01	0.00	0.00
Cottonwood	0.00	0.01	0.09	0.12	0.01	0.12	0.47	0.21	0.01	0.00
Erda	0.00	0.00	0.03	0.00	0.00	0.02	0.02	0.02	0.00	0.00
Hawthorne	0.00	0.03	0.18	0.14	0.01	0.19	0.52	0.24	0.01	0.00
Magna	0.00	0.02	0.06	0.02	0.04	0.07	0.14	0.18	0.00	0.02
Rose Park	0.00	0.04	0.16	0.14	0.02	0.25	0.25	0.17	0.02	0.00
Bountiful Viewmont	0.02	0.12	0.23	0.17	0.21	0.61	0.27	0.21	0.07	0.03
Ogden	0.02	0.04	0.06	0.11	0.18	0.29	0.14	0.09	0.04	0.04
Harrisville	0.01	0.03	0.04	0.07	0.06	0.19	0.18	0.06	0.04	0.03
Brigham City	0.02	0.03	0.02	0.03	0.07	0.15	0.12	0.04	0.01	0.02

Table 3.3.1: Change in modeled 24-hour PM_{2.5} due to eliminating VOC emissions from major stationary sources in the 2019 Serious PM_{2.5} SLC non-attainment area EI. Each row represents results at a specific SLC non-attainment area monitor. Each column represents one day in the modeled 10-day wintertime episode, starting on January 1.

Not only were changes in 24-hour modeled PM_{2.5} less than 1.5 µg/m³ at all monitors, changes were less than significant throughout the entire SLC non-attainment area (Figure 3.3.1, below). However, it is worth noting that changes in modeled PM_{2.5} along the eastern Salt Lake County mountain range were near 1.2 µg/m³; a threshold of significance provided in older EPA Prevention of Significant Deterioration (PSD) guidance.

1

Changes in PM_{2.5}

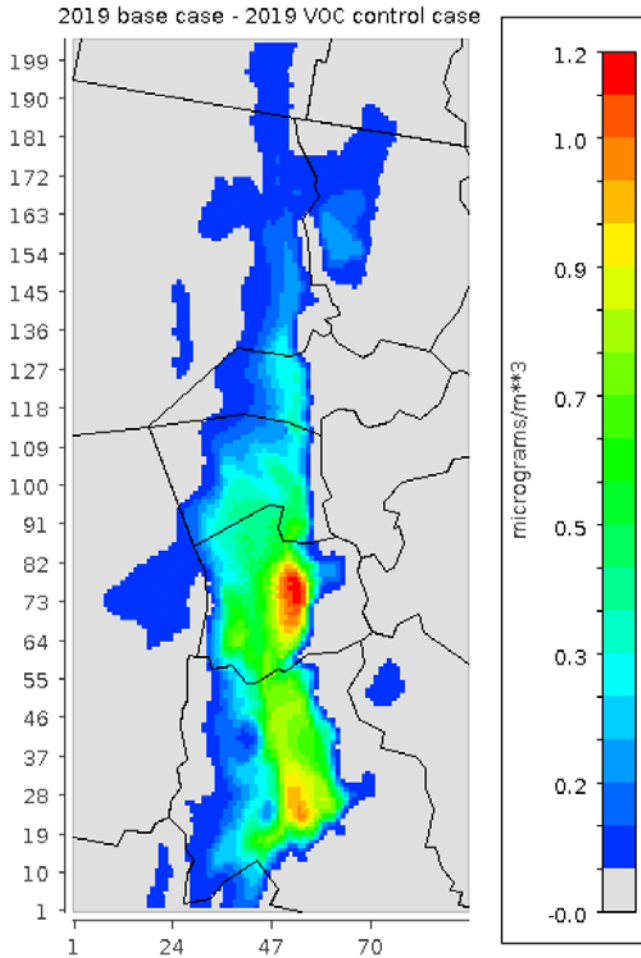


Figure 3.3.1: Change in modeled 24-hour PM_{2.5} due to eliminating VOC emissions from SLC non-attainment area major sources.

3.4 Precursor Demonstration for NH₃

Major stationary source ammonia (NH₃) comprises only 3% of the 2019 SLC non-attainment area emissions inventory. Not surprisingly, removing major source NH₃ resulted in less than significant changes in modeled PM_{2.5} at all monitors (Table 3.4.1, below).

The role of ammonia injection in the modeling should be noted. A significant amount (~40%) of ammonia emissions were added to the 2019 SIP modeling in order to improve ammonium nitrate performance. Injected ammonia was processed as a part of the small stationary sources inventory (i.e., non-point). The need to add so much non-inventoried ammonia means that the 2019 ammonia EI is possibly not that representative of reality. Therefore, there are large uncertainties concerning Utah ammonia emissions. Parts of northern Salt Lake County may even be ammonia-limited at times due to the large

abundance of NO_x emissions in the area (2017 UWFPS). A large UDAQ-funded scientific study is planned for 2019 - 2020. The goal of the scientific study is to discover ammonia sources along the Wasatch Front and ultimately improve Utah's ammonia emissions inventory.

2019 base case - 2019 NH3 control	Change in PM2.5 (ug/m3)									
	2011001	2011002	2011003	2011004	2011005	2011006	2011007	2011008	2011009	2011010
Herriman	0.00	0.00	0.01	0.03	0.00	0.00	0.32	0.10	0.02	0.00
Tooele	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.02	0.00	0.00
Cottonwood	0.00	0.00	0.01	0.07	0.00	0.01	0.58	0.29	0.01	0.00
Erda	0.00	0.00	0.01	0.00	0.00	0.02	0.02	0.04	0.00	0.00
Hawthorne	0.00	0.00	0.02	0.08	0.00	0.01	0.62	0.38	0.01	0.00
Magna	0.00	0.00	0.02	0.03	0.00	0.02	0.48	1.00	0.00	0.03
Rose Park	0.00	0.00	0.04	0.13	0.00	0.01	0.37	0.50	0.01	0.00
Bountiful Viewmont	0.00	0.00	0.02	0.16	0.00	0.01	0.12	0.51	0.02	0.00
Ogden	0.00	0.00	0.00	0.02	0.01	0.02	0.02	0.20	0.00	0.00
Harrisville	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.14	0.00	0.00
Brigham City	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.04	0.00	0.00

Table 3.4.1: Change in modeled 24-hour PM_{2.5} due to eliminating NH3 emissions from major stationary sources in the 2019 Serious PM_{2.5} SLC non-attainment area EI. Each row represents results at a specific SLC non-attainment area monitor. Each column represents one day in the modeled 10-day wintertime episode, starting on January 1.

Examining the entire non-attainment in Figure 3.4.1, below, a significant localized change in modeled PM_{2.5} due to major source ammonia was produced in western Salt Lake County. Interestingly, this is near the location where a significant change in modeled PM_{2.5} due to SO_x reductions was calculated (Figure 3.2.1).

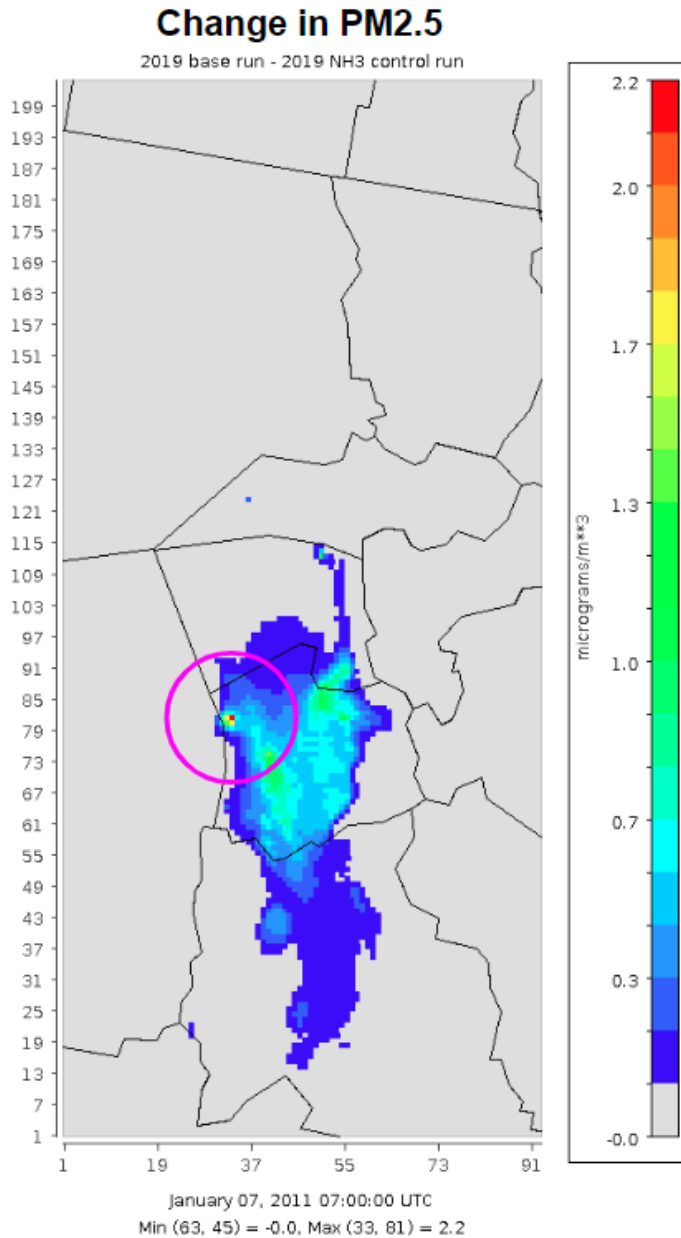


Figure 3.4.1: Change in modeled 24-hour PM_{2.5} due to eliminating all NH₃ emissions from major stationary sources in the SLC non-attainment area EI. Changes in PM_{2.5} greater than 1.5 µg/m³ were observed in western SLC County (noted by purple circle).

3.5 Precursor Demonstration for NO_x, SO_x, VOC, and NH₃

UDAQ conducted a supplemental precursor demonstration where SLC non-attainment area major stationary source NO_x, SO_x, VOC, and NH₃ emissions were jointly removed. As in prior analyses, the change in modeled 24-hour PM_{2.5} was calculated and tested for

significance against a threshold of 1.5 $\mu\text{g}/\text{m}^3$. The analysis produced significant differences in $\text{PM}_{2.5}$ at several monitors for multiple days (see Table 3.5.1, below).

2019 base case - 2019 all gas control case	Change in $\text{PM}_{2.5}$ ($\mu\text{g}/\text{m}^3$)									
	2011001	2011002	2011003	2011004	2011005	2011006	2011007	2011008	2011009	2011010
Herriman	0.00	0.00	0.28	0.62	0.04	0.04	0.80	0.49	0.58	0.13
Tooele	0.00	0.03	0.44	0.70	0.06	0.50	0.98	0.99	0.14	0.06
Cottonwood	0.01	0.05	0.86	1.26	0.11	0.11	1.11	0.64	0.45	0.21
Erda	0.00	0.04	0.61	0.63	0.15	0.44	1.65	1.56	0.05	0.11
Hawthorne	0.02	0.08	0.98	1.59	0.12	0.22	1.22	0.90	0.38	0.22
Magna	0.01	0.07	0.62	1.66	0.33	0.55	2.75	2.39	0.37	0.68
Rose Park	0.02	0.08	1.29	1.59	0.12	0.22	1.49	1.27	0.38	0.24
Bountiful Viewmont	0.05	0.17	2.05	1.86	0.66	-0.11	1.07	1.84	0.42	0.39
Ogden	0.06	0.08	0.38	1.20	0.68	1.12	1.65	1.47	0.25	0.40
Harrisville	0.06	0.14	0.24	0.85	0.47	1.11	1.49	1.32	0.20	0.29
Brigham City	0.33	0.29	0.31	0.66	0.65	1.46	1.81	1.57	0.10	0.41

Table 3.5.1: Change in modeled 24-hour $\text{PM}_{2.5}$ due to eliminating NO_x , SO_x , VOC, and NH_3 emissions from major stationary sources in the 2019 Serious $\text{PM}_{2.5}$ SLC non-attainment area EI. Each row represents results at a specific SLC non-attainment area monitor. Each column represents one day in the modeled 10-day wintertime episode, starting on January 1. Significant changes in modeled $\text{PM}_{2.5}$ are highlighted in red.

Below, Figure 3.5.1 shows 24-hour modeled $\text{PM}_{2.5}$ changes in the SLC non-attainment area for January 7. Beyond monitor locations, the largest change ($6.7 \mu\text{g}/\text{m}^3$) in modeled 24-hour $\text{PM}_{2.5}$ was seen in western Salt Lake County; which correlates with the large SO_x impact discussed in section 3.2 (Figure 3.2.1). Large localized changes in modeled $\text{PM}_{2.5}$ appeared in Davis County, with one spot near the Davis County border; This is consistent with the prior NO_x precursor demonstration discussed in section 3.1 (Figure 3.1.1). Eastern Box Elder County shows a broad impact from SLC non-attainment major stationary sources.

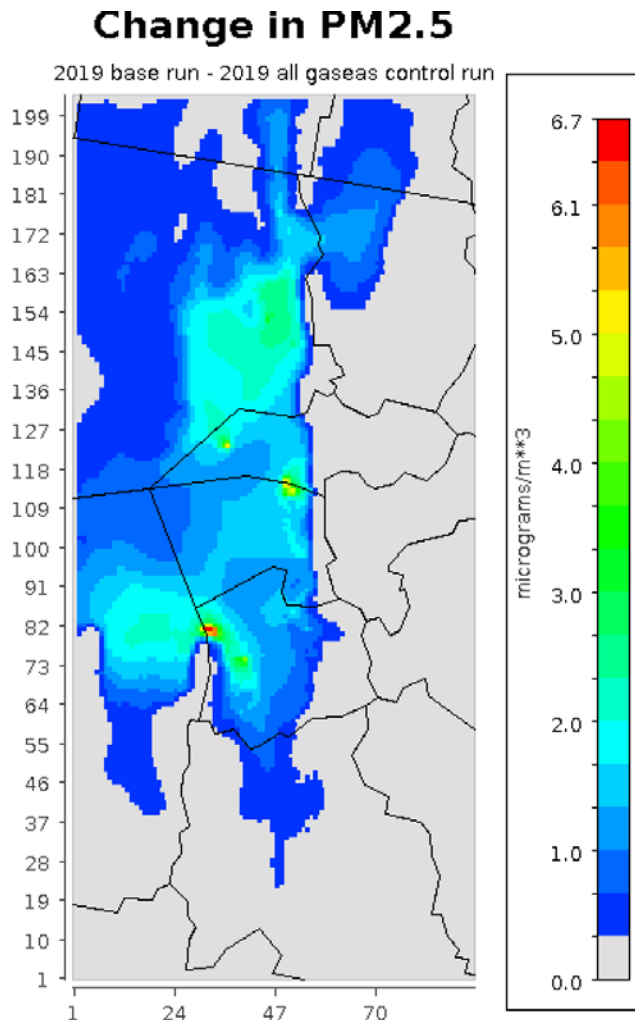


Figure 3.5.1: Change in modeled 24-hour PM_{2.5} on January 7 due to eliminating NO_x, SO_x, VOC, and NH₃ emissions from major stationary sources in the SLC non-attainment area EI. Significant changes in modeled PM_{2.5} appeared in several locations along the Wasatch Front. The largest change (6.7 µg/m³) was seen in western Salt Lake County.

4.0 Supplemental Source Apportionment (PSAT) Analysis

Another method to determine the PM_{2.5} contribution from SLC major stationary sources is source apportionment. For this analysis, UDAQ used the CAMx Particulate Matter Source Apportionment Technology (PSAT) to determine how much secondary PM_{2.5} came from major stationary sources in the SLC non-attainment area. PSAT does not determine the direct contribution from gas precursors, but PSAT can estimate how much secondary aerosol (nitrate, sulfate, ammonium) is from major stationary sources. For this

analysis, it is considered significant if the modeled PM_{2.5} concentrations attributed to major sources is greater than 1.5 µg/m³.

UDAQ tracked emissions from major stationary sources in the Salt Lake City non-attainment source region. UDAQ defined receptor cells in their PSAT analysis as 1.3 km grid-cells that were collocated with UDAQ PM_{2.5} FRM monitors in the SLC non-attainment area.

The PSAT analysis produced a 24-hour nitrate (NO₃) concentration of 1.74 µg/m³ that was attributed to SLC non-attainment area major stationary sources on January 7 at the Hawthorne monitor (Table 4.0.1, below). This was not observed in the NO_x precursor demonstration (section 3.1) where NO_x disbenefit effects in northern Salt Lake County played a large role in nitrate formation.

A sulfate (SO₄) concentration of 1.64 µg/m³ was attributed to SLC non-attainment area major stationary sources at the Magna monitor on the 7th day of the episode (Table 4.0.1). This supports the SO_x precursor demonstration results discussed in section 3.2 (Table 3.2.1), where eliminating major stationary source SO_x revealed a significant change in modeled PM_{2.5} at this location.

When we consider nitrate, sulfate and ammonium (NH₄) together, it appears SLC non-attainment area major stationary sources contributed to significant amounts of secondary aerosol at several UDAQ monitors. Other days in the episode did not show high attributions.

Date	Monitor	NH4 (point)	NO3 (point)	SO4 (point)	NH4+NO3+SO4 (point)
Jan. 7	HARRISV	0.03	0.99	0.40	1.42
	BOUNTIFUL	0.23	1.28	0.57	2.08
	MAGNA	0.39	1.23	1.64	3.25
	OGDEN	0.04	0.99	0.56	1.58
	TOOELE	0.01	0.31	0.52	0.84
	ERDA	0.03	0.54	0.80	1.36
	BRIGHAM	0.01	1.18	0.41	1.60
	HERRIMAN	0.31	0.79	0.35	1.45
	ROSE PARK	0.26	1.40	0.91	2.57
	HAWTHORNE	0.40	1.74	0.99	3.13

Table 4.0.1: 24-hour (January 7) secondary aerosol contribution from major stationary sources in the SLC non-attainment area at specific receptor sites collocated with PM_{2.5} FRM monitors. Contributions over 1.5 µg/m³ are highlighted in red.

When the SLC non-attainment area is examined as a whole, a significant amount of SO₄ is attributed to major stationary sources in western Salt Lake County, where a maximum change of 4.9 µg/m³ is shown (Figure 4.0.1 panel b). Localized SO₄ impacts are also seen in Weber County and north of the Brigham City monitor in Box Elder County. NO₃

impacts (Figure 4.0.1 panel a) appear in Box Elder County ($2.3 \mu\text{g}/\text{m}^3$) and along the Salt Lake/Davis County border. The PSAT results generally support the results from prior precursor demonstration modeling.

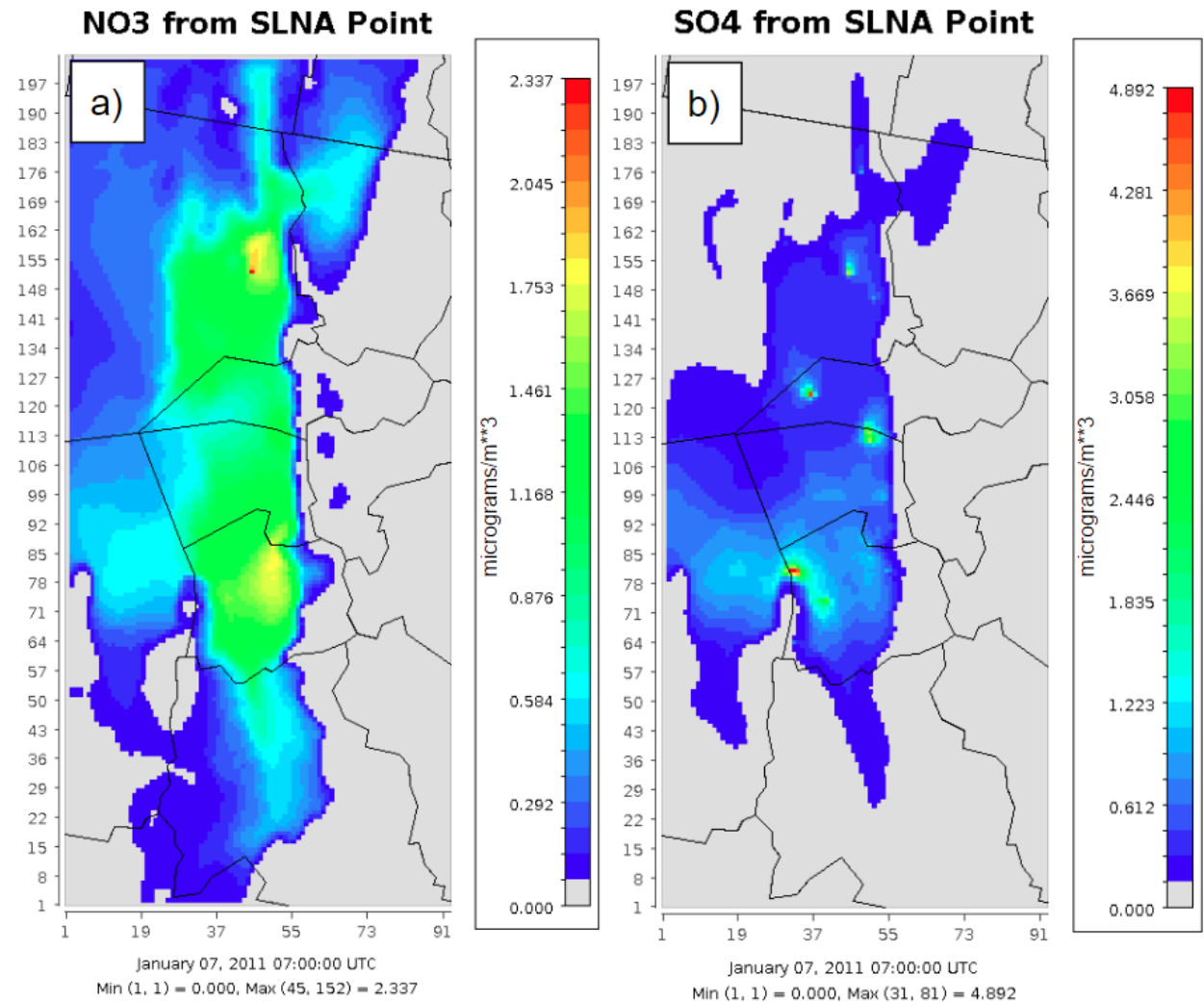


Figure 4.0.1: Contributions to modeled 24-hour $\text{PM}_{2.5}$ species from major stationary sources in the SLC non-attainment area. Left panel (a) shows the contribution of SLC major sources to modeled particulate nitrate (NO_3) concentrations, while the right panel (b) shows the contribution of SLC major sources to modeled particulate sulfate (SO_4) concentrations.

5.0 Conclusion

The precursor demonstrations discussed in this document present a “concentration-based” approach, where all (100%) of the major stationary source emissions for a given precursor are eliminated. This approach differs from a “sensitivity-based” approach, where changes in modeled $\text{PM}_{2.5}$ could be evaluated using different levels of emission

reductions (e.g., 30%, 50%, 70%). The precursor demonstrations presented here are meant to be useful in identifying if further modeled tests would be needed to discern significant precursor contributions from major stationary sources.

Throughout this document, $1.5 \mu\text{g}/\text{m}^3$ was considered a bright-line when determining the significance of changes in modeled $\text{PM}_{2.5}$. However, different conclusions could obviously be reached depending on this choice of threshold. Although supplemental analyses (spatial fields, bias-correction, PSAT) have been included here, the technical methodology used by UDAQ should not be considered definitive or exhaustive.

ITEM 5



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-088-18

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Thomas Gunter, Rules Coordinator

DATE: December 17, 2018

SUBJECT: FINAL ADOPTION: Change in Proposed Rule R307-110-10. Section IX, Control Measures for Area and Point Sources, Part A, Fine Particulate Matter.

On September 5, 2018, the Board proposed R307-110-10 for a 30 day public comment period. The public comment period was held from October 1 through October 31, 2018, and no comments were received.

The amendments to Section IX, Control Measures for Area and Point Sources, Part A, for Fine Particulate Matter will have to be incorporated into the Utah Air Quality Rules. R307-110-10 is the rule that incorporates the new amendments to Part A into the rules. If the Board adopts the amendments proposed to Part A, these amendments will become part of Utah's State Implementation Plan when the rule is finalized.

Recommendation: Staff recommends the Board adopt change in proposed rule R307-110-10 as amended.

1 **Appendix 1: Regulatory Impact Summary Table***

Fiscal Costs	FY 2019	FY 2020	FY 2021
State Government	\$0	\$0	\$0
Local Government	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0
Other Person	\$0	\$0	\$0
Total Fiscal Costs:	\$	\$0	\$0
Fiscal Benefits			
State Government	\$0	\$0	\$0
Local Government	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0
Other Persons	\$0	\$0	\$0
Total Fiscal Benefits:	\$0	\$0	\$0
Net Fiscal Benefits:	\$0	\$0	\$0

2 *This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they
 3 will not be included in this table. Inestimable impacts for State Government, Local Government, Small Businesses
 4 and Other Persons are described in the narrative. Inestimable impacts for Non-Small Businesses are described in
 5 Appendix 2.
 6

7 **Appendix 2: Regulatory Impact to Non-Small Businesses**

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 9 This rule change is not expected to have any fiscal impacts on large
 10 businesses revenues or expenditures, because all controls were
 11 required for the previous version of Section IX, Part A and therefore
 12 will not cost or benefit any business further.

13 The Executive Director of the Department of Environmental Quality,
 14 Alan Matheson, has reviewed and approved this fiscal analysis.

15
 16 ***Non-small business" means a business employing 50 or more persons; "small business" means a business employing
 17 fewer than 50 persons.
 18

19 **R307. Environmental Quality, Air Quality.**

20 **R307-110. General Requirements: State Implementation Plan.**

21 **R307-110-10. Section IX, Control Measures for Area and Point Sources,
 22 Part A, Fine Particulate Matter.**

23 The Utah State Implementation Plan, Section IX, Control Measures
 24 for Area and Point Sources, Part A, Fine Particulate Matter, as most
 25 recently amended by the Utah Air Quality Board on ~~December 2~~ January
 26 2, 201~~8~~9, pursuant to Section 19-2-104, is hereby incorporated by
 27 reference and made a part of these rules.
 28

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

30 **Date of Enactment or Last Substantive Amendment: ~~[June 7]~~, 201~~8~~9**

31 **Notice of Continuation: January 27, 2017**

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

ITEM 6



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-094-18

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Bill Reiss, Environmental Engineer

DATE: December 18, 2018

SUBJECT: FINAL ADOPTION: SIP Subsection IX. Part H: Emission Limits and Operating Practices. Specifically Requirements in Subparts H. 1, 2, 11, and 12, as Amended.

On June 6, 2018, the Board proposed for public comment amendments to SIP Subsection IX. Part H Control Measures for Area and Point Sources, Emission Limits and Operating Practices Subparts 1, 2, 11 and 12. The terms in these subparts enforce the plan requirements for stationary sources located in the Salt Lake City PM_{2.5} nonattainment area (SLC NAA).

The originally proposed amendments to subparts 1 and 2 specifically affect PM₁₀ requirements, but were included to correct a calculation error, add clarification, and provide consistency throughout Part H.

The amendments addressing PM_{2.5} in subparts 11 and 12 were proposed to support a Serious Area SIP for the SLC NAA, providing therein for the implementation of best available control measures and technologies (BACM/BACT) at the large stationary “point” sources in the nonattainment area. These provisions include enforceable emission limitations as well as schedules and timetables for compliance.

Public comments were accepted from July 1st through August 15th. Numerous comments were received, and DAQ prepared a document summarizing and responding to those comments in advance of the October Board meeting.

The BACM / BACT requirements (in Part H) for stationary point sources had initially been proposed as an element that was “generally independent” of the attainment demonstration underlying the Serious Area SIP. For this reason, it was released before DAQ could complete the remainder of the SIP. Comments received on the earlier BACT requirements in Part H took issue with this stated disconnection from the broader SIP and its underlying attainment demonstration.

Of the many comments received, one in particular from the Utah Petroleum Association (UPA) contended that it was premature to consider BACM/BACT for all four plan precursors for the major stationary point sources until the air quality modeling could ascertain whether in fact certain PM_{2.5} precursor emissions could or could not be exempted from the BACM/BACT provisions.

UPA's comment was supported by a precursor demonstration that concluded, for each of the PM_{2.5} Plan Precursors (NO_x, SO_x, VOC, and NH₃), that the emissions from existing major stationary sources located in the nonattainment area do not contribute significantly to ambient PM_{2.5} levels that exceed the standard in the area.

UDAQ also received supplemental information for the BACM/BACT reviews for four of the stationary sources: Hexcel, Rio Tinto Kennecott, Compass Minerals, and ATK Launch Systems, Inc. Promontory. On October 3, 2018, staff explained that this supplemental information would result in substantive changes to Part H.

Thus, Part H was re-proposed for public comment on October 3rd. This re-proposal also included several amendments made by the Board itself. These intended:

- That all stack testing be required at least once per year
- Elimination of differences in emission limitations by season, such that the more stringent limit be applied throughout the year. This would apply in six specific instances.
- Only the combustion of natural gas at Kennecott's Unit 4, even during summer months

A 30-day period of public review was held on this re-proposal throughout the month of November. Again, numerous comments were received, including some from DAQ staff. These comments have been summarized, with responses provided thereto, and included here as Attachment B.

Both SIP Parts, A and H, have been brought before the Board today for final adoption.

Regarding the issue of major stationary source precursor demonstrations, DAQ had indicated it would independently evaluate the contribution made by existing major stationary sources to the PM_{2.5} levels addressed by this Serious Area SIP. DAQ has done so, and the (draft) analysis is included as Attachment C to Agenda Item IV. This analysis has informed DAQ's responses to those comments, which are summarized and addressed in Attachment B to that same Agenda Item.

Most significantly, staff is not recommending that Utah elect to include any major stationary source PM_{2.5} precursor demonstration in its Serious Area SIP at this time.

Furthermore, it is not recommending that the emission limits and operating conditions articulated for major stationary sources in Part H be made conditional on the approval by EPA of any such major stationary source precursor demonstration.

Recommendation: Staff recommends that the Board adopt SIP Subsection IX. Part H: Emission Limits and Operating Practices, as further amended in subparts 1, 2, 11, and 12.

Attachments A: Amended SIP Subsection IX. Part H: Emission Limits and Operating Practices. Specifically Proposed for Amendment are Requirements in Subparts H. 1, 2, 11, and 12.

Attachments B: Response to Comments Received During the November SIP Subsection IX. Part H Comment Period

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ATTACHMENT A

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1 **Utah State Implementation Plan**

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5 **Emission Limits**
6 **and Operating Practices**

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9 **Section IX, Part H**

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52 Adopted by the Air Quality Board
53 , 2019

H.1 General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM₁₀ Requirements

- a. Except as otherwise outlined in individual conditions of this Subsection IX.H.1 listed below, the terms and conditions of this Subsection IX.H.1 shall apply to all sources subsequently addressed in Subsection IX.H.2 and IX.H.3. Should any inconsistencies exist between these two subsections, the source specific conditions listed in IX.H.2 and IX.H.3 shall take precedence.
- b. Definitions.
 - i. The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.
 - ii. Natural gas curtailment means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment.
- c. Recordkeeping and Reporting
 - i. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request, and shall include a period of two years ending with the date of the request.
 - ii. Each source shall comply with all applicable sections of R307-150 Emission Inventories.
 - iii. Each source shall submit a report of any deviation from the applicable requirements of this Subsection IX.H, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be submitted to the Director no later than 24-months following the deviation or earlier if specified by an underlying applicable requirement. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107.
- d. Emission Limitations.
 - i. All emission limitations listed in Subsections IX.H.2 and IX.H.3 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.2 and IX.H.3.
 - ii. All emission limitations of PM₁₀ listed in Subsections IX.H.2 and IX.H.3 include both filterable and condensable PM, unless otherwise specified in the source specific conditions listed in IX.H.2 and IX.H.3.
- e. Stack Testing.

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- i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.2 and I.X.H.3 shall be performed in accordance with the following:
 - A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved testing methods acceptable to the Director. Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.
 - B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2, EPA Test Method No. 19 “SO₂ Removal & PM, SO₂ NO_x Rates from Electric Utility Steam Generators”, or other EPA-approved testing methods acceptable to the Director.
 - C. PM: 40 CFR 60, Appendix A Methods 5, 5b, 5f, 17 or other EPA-approved testing methods acceptable to the Director.
 - D. PM₁₀: 40 CFR 51, Appendix M, Methods 201a and 202, or other EPA approved testing methods acceptable to the Director. If a method other than 201a is used, the portion of the front half of the catch considered PM₁₀ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.
 - E. SO₂: 40 CFR 60 Appendix A, Method 6C or other EPA-approved testing methods acceptable to the Director.
 - F. NO_x: 40 CFR 60 Appendix A, Method 7E or other EPA-approved testing methods acceptable to the Director.
 - G. Calculations: To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.
 - H. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director.
 - I. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved.
 - f. Continuous Emission and Opacity Monitoring.

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- i. For all continuous monitoring devices, the following shall apply:
 - A. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of unaffected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13. Flow measurement shall be in accordance with the requirements of 40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75, Appendix A.
 - B. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 13; and 40 CFR 60, Appendix B – Performance Specifications.
 - ii. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.
- g. Petroleum Refineries.
- i. Limits at Fluid Catalytic Cracking Units (FCCU)
 - A. FCCU SO₂ Emissions
 - I. Each owner or operator of an FCCU shall comply with an SO₂ 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.
 - II. Compliance with this limit shall be determined ~~[by following 40 C.F.R. §60.105a(g)]~~ using a CEM in accordance with IX.H.1.f.
 - B. FCCU PM Emissions
 - I. Each owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds burn-off.
 - II. Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) or 40 C.F.R. §60.104a(d) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests ~~[annually]~~ once every three (3) years at each FCCU.
 - III. No later than January 1, 2019, each owner or operator of an FCCU subject to NSPS Ja shall install, operate and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters from the FCCU ~~[for determination of source-wide particulate emissions]~~ and control devices as per the requirements of 40 CFR 60.105a(b)(1). No later than January 1, 2019, each owner or operator of an FCCU not subject to NSPS Ja shall install, operate and maintain a continuous opacity monitoring system to measure and record opacity from the FCCU as per the requirements of 40 CFR 63.1572(b) and comply with the opacity limitation as per the requirements of Table 7 to Subpart UUU of Part 63.

1 ii. Limits on Refinery Fuel Gas.

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3 A. All petroleum refineries in or affecting any PM_{2.5} nonattainment area or any PM₁₀
4 nonattainment or maintenance area shall reduce the H₂S content of the refinery
5 plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be
6 based on a rolling average of 365 days. The owner/operator shall comply with the
7 fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping
8 and reporting requirements of 40 CR 60.108a. As used herein, refinery “plant gas”
9 shall have the meaning of “fuel gas” as defined in 40 CFR 60.101a, and may be
10 used interchangeably.

11
12 B. For natural gas, compliance is assumed while the fuel comes from a public utility.

13
14 iii. Sulfur Removal Units

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16 A. All petroleum refineries in or affecting any PM_{2.5} nonattainment area or any
17 PM₁₀ nonattainment or maintenance area shall require:

18
19 I. Sulfur removal units/plants (SRUs) that are at least 95% effective in
20 removing sulfur from the streams fed to the unit; or

21
22 II. SRUs that meet the SO₂ emission limitations listed in 40 CFR 60.102a(f)(1) or
23 60.102a(f)(2) as appropriate.

24
25 B. The amine acid gas and sour water stripper acid gas shall be processed in the
26 SRU(s).

27
28 C. Compliance shall be demonstrated by daily monitoring of flows to the SRU(s).
29 Continuous monitoring of SO₂ concentration in the exhaust stream shall be
30 conducted via CEM as outlined in IX.H.1.f above. Compliance shall be
31 determined on a rolling
32 30-day average.

33
34 iv. No Burning of Liquid Fuel Oil in Stationary Sources

35
36 A. No petroleum refineries in or affecting any PM_{2.5} nonattainment area or any PM₁₀
37 nonattainment or maintenance area shall be allowed to burn liquid fuel oil in
38 stationary sources except during natural gas curtailments or as specified in the
39 individual subsections of Section IX, Part H.

40
41 B. The use of diesel fuel meeting the specifications of 40 CFR 80.510 in
42 standby or emergency equipment is exempt from the limitation of
43 IX.H.1.g.iv.A above.

44
45 v. Requirements on Hydrocarbon Flares.

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47 A. All hydrocarbon flares at petroleum refineries located in or affecting any PM_{2.5}
48 nonattainment area or any PM₁₀ nonattainment or maintenance area within the
49 State shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR
50 60.100a–109a), if not already subject under the flare applicability provisions of
51 Ja.

1
2 B. No later than January 1, 2019, all major source petroleum refineries in or affecting
3 any PM_{2.5} nonattainment area or an PM₁₀ nonattainment or maintenance area shall
4 either 1) install and operate a flare gas recovery system designed to limit
5 hydrocarbon flaring produced from each affected flare during normal operations to
6 levels below the values listed in 40 CFR 60.103a(c), or 2) limit flaring during normal
7 operations to 500,000 scfd for each affected flare. Flare gas recovery is not required
8 for dedicated SRU flare and header systems, or HF flare and header systems.

H.2 Source Specific Emission Limitations in Salt Lake County PM₁₀ Nonattainment/Maintenance Area

a. Big West Oil Company

i. Source-wide PM₁₀ Cap

No later than January 1, 2019, combined emissions of PM₁₀ shall not exceed 1.037 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.a.i.B below, the default emission factors to be used are as follows:

Natural gas:

Filterable PM₁₀: 1.9 lb/MMscf

Condensable PM₁₀: 5.7 lb/MMscf

Plant gas:

Filterable PM₁₀: 1.9 lb/MMscf

Condensable PM₁₀: 5.7 lb/MMscf

Fuel Oil: The PM₁₀ emission factor shall be determined from the latest edition of AP-42 or other EPA-approved methods.

Cooling Towers: The PM₁₀ emission factor shall be determined from the latest edition of AP-42 or other EPA-approved methods.

FCC Stacks: The PM₁₀ emission factor shall be established by stack test.

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. The default emission factors listed in IX.H.2.a.i.A above apply until such time as stack testing is conducted as provided in IX.H.1.e or as outlined below:

PM₁₀ stack testing on the FCC shall be performed initially no later than January 1, 2019 and at least [annually]once every three (3) years thereafter. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM₁₀ Cap shall be determined for each day as follows:

Total 24-hour PM₁₀ emissions for the emission points shall be calculated by

1 adding the daily results of the PM₁₀ emissions equations listed below for
2 natural gas, plant gas, and fuel oil combustion. These emissions shall be added
3 to the emissions from the cooling towers, and the FCCs to arrive at a combined
4 daily PM₁₀ emission total.

5
6 For purposes of this subsection a “day” is defined as a period of 24-
7 hours commencing at midnight and ending at the following midnight.

8
9 Daily gas consumption shall be measured by meters that can delineate the
10 flow of gas to the boilers, furnaces and the SRU incinerator.

11
12 The equation used to determine emissions from these units shall be as
13 follows: Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24
14 hrs)/(2,000 lb/ton)

15
16 Daily fuel oil consumption shall be monitored by means of leveling gauges
17 on all tanks that supply combustion sources.

18
19 The daily PM₁₀ emissions from the FCC shall be calculated using the following
20 equation:

21
22
$$E = FR * EF$$

23
24 Where:

25 E = Emitted PM₁₀

26 FR = Feed Rate to Unit (kbbls/day)

27 EF = emission factor (lbs/kbbl), established by the most recent stack test

28
29 Results shall be tabulated for each day, and records shall be kept which include
30 the meter readings (in the appropriate units) and the calculated emissions.

31
32 ii. Source-Wide NO_x Cap

33
34 No later than January 1, 2019, combined emissions of NO_x shall not exceed 0.80 tons per
35 day (tpd) and 195 tons per rolling 12-month period.

36
37 A. Setting of emission factors:

38
39 The emission factors derived from the most current performance test shall be
40 applied to the relevant quantities of fuel combusted. Unless adjusted by
41 performance testing as discussed in IX.H.2.a.ii.B below, the default emission
42 factors to be used are as follows:

43
44 Natural gas: shall be determined from the latest edition of AP-42 or other EPA-
45 approved methods.

46 Plant gas: assumed equal to natural gas

Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-approved methods.

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

- B. The default emission factors listed in IX.H.2.a.ii.A above apply until such time as stack testing is conducted as provided in IX.H.1.e or as outlined below:

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 40 MMBtu/hr has been performed. NO_x emissions for the FCC are monitored with a continuous emission monitoring system. Refinery Boilers and heaters over 40 MMBtu/hr but less than 100 MMBtu/hr are in compliance with monitoring and work practice standards of Subpart DDDD of Part 63.

- C. Compliance with the source-wide NO_x Cap shall be determined for each day as follows:

Total 24-hour NO_x emissions shall be calculated by adding the emissions for each emitting unit. The emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor, and summing the results.

Daily plant gas consumption at the furnaces, boilers and SRU incinerator shall be measured by flow meters. The equations used to determine emissions shall be as follows:

$$\text{NO}_x = \text{Emission Factor (lb/MMscf)} * \text{Gas Consumption (MMscf/24 hrs)} / (2,000 \text{ lb/ton})$$
 Where the emission factor is derived from the fuel used, as listed in IX.H.2.a.ii.A above

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The daily NO_x emissions from the FCC shall be calculated using a CEM as outlined in IX.H.1.f

Total daily NO_x emissions shall be calculated by adding the results of the above NO_x equations for natural gas and plant gas combustion to the estimate for the FCC.

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

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

1
2 iii. Source-Wide SO₂ Cap
3

4 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 0.60 tons
5 per day (tpd) and 140 tons per rolling 12-month period.
6

7 A. Setting of emission factors:
8

9 The emission factors derived from the most current performance test shall be
10 applied to the relevant quantities of fuel combusted. The default emission factors to
11 be used are as follows:
12

13 Natural Gas - 0.60 lb SO₂/MMscf gas
14

15 Plant Gas: The emission factor to be used in conjunction with plant gas
16 combustion shall be determined through the use of a CEM as outlined in
17 IX.H.1.f. .
18

19 SRUs: The emission rate shall be determined by multiplying the sulfur
20 dioxide concentration in the flue gas by the flow rate of the flue gas. The
21 sulfur dioxide concentration in the flue gas shall be determined by CEM as
22 outlined in IX.H.1.f.
23

24 Fuel oil: The emission factor to be used for combustion shall be calculated based on
25 the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-
26 approved equivalent acceptable to the Director, and the density of the fuel oil, as
27 follows:
28

29
$$EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt. \% S/100} * (64 \text{ lb SO}_2\text{/32}$$

30
$$\text{lb S)}$$

31

32 Where mixtures of fuel are used in a Unit, the above factors shall be
33 weighted according to the use of each fuel.
34

35 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
36 follows: Total daily SO₂ emissions shall be calculated by adding the daily SO₂
37 emissions for natural gas and plant fuel gas combustion, to those from the FCC and
38 SRU stacks.
39

40 The daily SO_x emission from the FCC shall be calculated using a CEM as outlined in
41 IX.H.11.f.
42

43 Daily natural gas and plant gas consumption shall be determined through the
44 use of flow meters.
45

46 Daily fuel oil consumption shall be monitored by means of leveling gauges on all

1 tanks that supply combustion sources.

2
3 For purposes of this subsection a “day” is defined as a period of 24-hours
4 commencing at midnight and ending at the following midnight.

5
6 Results shall be tabulated for each day, and records shall be kept which include
7 CEM readings for H₂S (averaged for each day), all meter reading (in the
8 appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel
9 oil is burned), and the calculated emissions.

10
11 iv. Emergency and Standby Equipment

12
13 A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is
14 allowed in standby or emergency equipment at all times.

15
16 v. Alternate Startup and Shutdown Requirements

17
18 A. During any day which includes startup or shutdown of the FCCU, combined
19 emissions of SO₂ shall not exceed 1.2 tons per day (tpd). For purposes of this
20 subsection, a "day" is defined as a period of 24-hours commencing at midnight and
21 ending at the following midnight.

22
23 B. The total number of days which include startup or shutdown of the FCCU shall
24 not exceed ten (10) per 12-month rolling period.

25
26 vi. ~~Requirements on Hydrocarbon Flares~~

27
28 ~~A. No later than January 1, 2021, routine flaring will be limited to 300,000 scfd for~~
29 ~~each affected flare.]~~ No later than January 1, 2019, the owner/operator shall install
30 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.

- 1 b. Bountiful City Light and Power: Power Plant
- 2 i. Emissions to the atmosphere shall not exceed the following rates and
- 3 concentrations:
- 4 A. GT #1 (5.3 MW Turbine)
- 5 Exhaust Stack: 0.6 g NO_x / kW-hr
- 6
- 7 B. GT #2 and GT #3 (each TITAN Turbine) Exhaust Stack: 7.5 lb NO_x / hr
- 8
- 9 ii. Compliance to the above emission limitations shall be determined by stack test.
- 10 Stack testing shall be performed as outlined in IX.H.1.e.
- 11
- 12 A. Initial stack tests have been performed. Each turbine shall be tested at least once
- 13 per year.
- 14
- 15 iii. Combustion Turbine Startup / Shutdown Emission Minimization Plan
- 16
- 17 A. Startup begins when natural gas is supplied to the combustion turbine(s) with the
- 18 intent of combusting the fuel to generate electricity. Startup conditions end within
- 19 sixty (60) minutes of natural gas being supplied to the turbine(s).
- 20
- 21 B. Shutdown begins with the initiation of the stop sequence of a turbine until the
- 22 cessation of natural gas flow to the turbine.
- 23
- 24 C. Periods of startup or shutdown shall not exceed two (2) hours per combustion
- 25 turbine per day.
- 26
- 27
- 28

- 1 c. Central Valley Water Reclamation Facility: Wastewater Treatment Plant
- 2 i. NO_x emissions from the operation of all engines at the plant shall not exceed 0.648
- 3 tons per day.
- 4
- 5 ii. Compliance with the emission limitation shall be determined by summing the
- 6 emissions from all the engines. Emission from each engine shall be calculated from
- 7 the following equation:
- 8
- 9 Emissions (tons/day) = (Power production in kW-hrs/day) x (Emission
- 10 factor in grams/kW- hr) x (1 lb/453.59 g) x (1 ton/2000 lbs)
- 11
- 12 A. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall
- 13 be tested at least ~~annually~~ every three years from the previous test.
- 14
- 15 B. The NO_x emission factor for each engine shall be derived from the most recent
- 16 stack test.
- 17
- 18 C. NO_x emissions shall be calculated on a daily basis.
- 19
- 20 D. A day is equivalent to the time period from midnight to the following
- 21 midnight.
- 22
- 23 E. The number of kilowatt hours generated by each engine shall be determined
- 24 by examination of electrical meters, which shall record electricity
- 25 production on a continuous basis.

d. Chevron Products Company

i. Source-wide PM₁₀ Cap

No later than January 1, 2019, combined emissions of PM₁₀ shall not exceed 0.715 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.d.i.B below, the default emission factors to be used are as follows:

Natural gas:

Filterable PM₁₀: 1.9 lb/MMscf

Condensable PM₁₀: 5.7 lb/MMscf

Plant gas:

Filterable PM₁₀: 1.9 lb/MMscf

Condensable PM₁₀: 5.7 lb/MMscf

HF alkylation polymer: shall be determined from the latest edition of AP-42 (HF alkylation polymer treated as fuel oil #6) or other EPA-approved methods.

Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-approved methods.

Cooling Towers: shall be determined from the latest edition of AP-42 or other EPA-approved methods.

FCC Stack:

The PM₁₀ emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. The default emission factors listed in IX.H.2.d.i.A above apply until such time as stack testing is conducted as provided in IX.H.1.e or as outlined below:

Initial PM₁₀ stack testing on the FCC stack has been performed and shall be conducted at least [annually] once every three (3) years from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM₁₀ Cap shall be determined for each day as follows:

Total 24-hour PM₁₀ emissions for the emission points shall be calculated by adding the daily results of the PM₁₀ emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, and the FCC to arrive at a combined daily PM₁₀ emission total. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The equation used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton) Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NO_x Cap

No later than January 1, 2019, combined emissions of NO_x shall not exceed 2.1 tons per day (tpd) and 766.5 tons per rolling 12-month period.

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.d.ii.B below, the default emission factors to be used are as follows:

Natural gas: shall be determined from the latest edition of AP-42 Plant gas: assumed equal to natural gas or other EPA-approved methods.

Alkylation polymer: shall be determined from the latest edition of AP-42 (as fuel oil #6) or other EPA-approved methods.

Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-approved methods.

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. The default emission factors listed in IX.H.2.d.ii.A above apply until such time as stack testing is conducted as provided in IX.H.1.e or as outlined below:

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above

1 100 MMBtu/hr has been performed and shall be conducted at least [annually] once every
2 three (3) years from the date of the last stack test. At that time a new flow-weighted
3 average emission factor in terms of: lbs/MMBtu shall be derived. Stack testing shall be
4 performed as outlined in IX.H.1.e.
5

6 C. Compliance with the source-wide NO_x Cap shall be determined for each day as
7 follows:
8

9 Total 24-hour NO_x emissions shall be calculated by adding the emissions for each
10 emitting unit. The emissions for each emitting unit shall be calculated by multiplying
11 the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted
12 at each affected unit by the associated emission factor, and summing the results.
13

14 A NO_x CEM shall be used to calculate daily NO_x emissions from the FCC. Emissions
15 shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by
16 the flow rate of the flue gas. The NO_x concentration in the flue gas shall be determined
17 by a CEM as outlined in IX.H.1.f.
18

19 For purposes of this subsection a “day” is defined as a period of 24-hours commencing
20 at midnight and ending at the following midnight.
21

22 Daily natural gas and plant gas consumption shall be determined through the use of
23 flow meters.
24

25 Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks
26 that supply combustion sources.
27

28 Results shall be tabulated for each day, and records shall be kept which include the
29 meter readings (in the appropriate units) and the calculated emissions.
30

31 iii. Source-wide SO₂ Cap

32 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 1.05 tons per day
33 (tpd) and 383.3 tons per rolling 12-month period.
34

35 A Setting of emission factors:
36

37 The emission factors derived from the most current performance test shall be applied to
38 the relevant quantities of fuel combusted. The default emission factors to be used are as
39 follows:
40

41 FCC: The emission rate shall be determined by the FCC SO₂ CEM as outlined in
42 IX.H.1.f.
43

44 SRUs: The emission rate shall be determined by multiplying the sulfur dioxide
45 concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide
46 concentration in the flue gas shall be determined by CEM as outlined in IX.H.1.f.

1
2 Natural gas: EF = 0.60 lb/MMscf
3

4 Fuel oil & HF Alkylation polymer: The emission factor to be used for combustion shall
5 be calculated based on the weight percent of sulfur, as determined by ASTM Method D-
6 4294-89 or EPA-approved equivalent acceptable to the Director, and the density of the
7 fuel oil, as follows:
8

9
$$EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt.\% S/100} * (64 \text{ lb SO}_2\text{/32 lb S)}$$

10

11 Plant gas: the emission factor shall be calculated from the H₂S measurement obtained
12 from the H₂S CEM.
13

14 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
15 according to the use of each fuel.
16

17 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as follows:
18

19 Total daily SO₂ emissions shall be calculated by adding the daily SO₂ emissions for
20 natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.
21

22 Daily natural gas and plant gas consumption shall be determined through the use of
23 flow meters.
24

25 Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks
26 that supply combustion sources.
27

28 Results shall be tabulated for each day, and records shall be kept which include CEM
29 readings for H₂S (averaged for each one-hour period), all meter reading (in the
30 appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil
31 is burned), and the calculated emissions.
32

33 iv. Emergency and Standby Equipment and Alternative Fuels
34

35 A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed
36 in standby or emergency equipment at all times.
37

38 B. HF alkylation polymer may be burned in the Alky Furnace (F-36017).
39

40 C. Plant coke may be burned in the FCC Catalyst Regenerator.
41

42 v. Compressor Engine Requirements
43

44 A. Emissions of NO_x from each rich-burn compressor engine shall not exceed the
45 following:
46

Engine Number	NO _x in ppmvd @ 0% O ₂
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 ~~annually~~ once every three (3) years from the date of the last stack test thereafter. Stack testing shall be performed as outlined in IX.H.1.e.

vi. Flare Calculation

- A. Chevron's Flare #3 receives gases from its Isomerization unit, Reformer unit as well as its HF Alkylation Unit. The HF Alkylation Unit's flow contribution to Flare #3 will not be included in determining compliance with the flow restrictions set in IX.H.1.g.v.B

- i. 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, 3	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)

1 e. Hexcel Corporation: Salt Lake Operations

- 2
3 i. The following limits shall not be exceeded for fiber line
4 operations:

5
6 A. 5.50 MMscf of natural gas consumed per day.

7
8 B. 0.061 MM pounds of carbon fiber produced per day.

9
10 C. Compliance with each limit shall be determined by the following methods:

11
12 I. Natural gas consumption shall be determined by examination of natural
13 gas billing records for the plant and onsite pipe-line metering.

14
15 II. Fiber production shall be determined by examination of plant production
16 records. III. Records of consumption and production shall be kept on a daily
17 basis for all periods when the plant is in operation.

- 18
19 ii. After a shutdown and prior to startup of fiber lines 13, 14, 15, or 16, the line's
20 baghouse(s) shall be started and remain in operation during production.

21
22 A. During fiber line production, the static pressure differential across the filter media
23 shall be within the manufacturer's recommended range and shall be recorded daily.

24
25 B. The manometer or the differential pressure gauge shall be calibrated according to
26 the manufacturer's instructions at least once every 12 months.

f. Holly Refining and Marketing Company

i. Source-wide PM₁₀ Cap

No later than January 1, 2019, PM₁₀ emissions from all sources shall not exceed 0.416 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.g.i.B below, the default emission factors to be used are as follows:

Natural gas or Plant gas:

non-NSPS combustion equipment: 7.65 lb PM₁₀/MMscf

NSPS combustion equipment: 0.52 lb PM₁₀/MMscf

Fuel oil:

The filterable PM₁₀ emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

$$\text{PM}_{10} \text{ (lb/1000 gal)} = (10 * \text{wt. \% S}) + 3.22$$

The condensable PM₁₀ emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.

Cooling Towers: The PM₁₀ emission factor shall be determined from the latest edition of AP-42.

FCC Wet Scrubbers:

The PM₁₀ emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III. As an alternative to a continuous parameter monitor system or continuous opacity monitoring system for PM emissions from any FCCU controlled by a wet gas scrubber, as required in Subsection IX.H.1.g.i.B.III, the owner/operator may satisfy the opacity monitoring requirements from its FCC Units with wet gas scrubbers through an alternate monitoring program as approved by the EPA and acceptable to the Director.

B. The default emission factors listed in IX.H.2.f.i.A above apply until such time as stack testing is conducted as outlined below:

Initial stack testing on all NSPS combustion equipment shall be conducted no later than January 1, 2019 and at least annually once every three (3) years from the date of the last stack test. At that time a new flow-weighted average emission factor in terms of: lb PM₁₀/MMBtu shall be derived. Stack testing shall be

1 performed as outlined in IX.H.1.e.

2
3 C. Compliance with the source-wide PM₁₀ Cap shall be determined for each
4 day as follows:

5
6 Total 24-hour PM₁₀ emissions for the emission points shall be calculated by adding
7 the daily results of the PM₁₀ emissions equations listed below for natural gas, plant
8 gas, and fuel oil combustion. These emissions shall be added to the emissions
9 from the cooling towers and wet scrubbers to arrive at a combined daily PM₁₀
10 emission total.

11
12 For purposes of this subsection a “day” is defined as a period of 24-hours
13 commencing at midnight and ending at the following midnight.

14
15 Daily natural gas and plant gas consumption shall be determined through the
16 use of flow meters on all gas-fueled combustion equipment.

17
18 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
19 tanks that supply fuel oil to combustion sources.

20
21 The equations used to determine emissions for the boilers and furnaces shall
22 be as follows:

23
24 Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural/Plant Gas
25 Consumption
26 (MMscf/day)/(2,000 lb/ton)

27
28 Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption
29 (kgal/day)/(2,000 lb/ton)

30
31 Results shall be tabulated for each day, and records shall be kept which
32 include all meter readings (in the appropriate units), and the calculated
33 emissions.

34
35 ii. Source-wide NO_x Cap

36 No later than January 1, 2019, NO_x emissions into the atmosphere from all emission
37 points shall not exceed 347.1 tons per rolling 12-month period and 2.09 tons per day
38 (tpd).

39
40 A. Setting of emission factors:

41
42 The emission factors derived from the most current performance test shall be
43 applied to the relevant quantities of fuel combusted. Unless adjusted by
44 performance testing as discussed in IX.H.2.g.ii.B below, the default emission
45 factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:

Low NO_x burners (LNB): 41 lbs/MMscf

Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu

Next Generation Ultra Low NO_x burners (NGULNB): 0.10 lbs/MMbtu

Selective catalytic reduction (SCR): 0.02 lbs/MMbtu

All other combustion burners: 100 lb/MMscf

Where:

"Natural gas/refinery fuel gas" shall represent any combustion of natural gas, refinery fuel gas, or combination of the two in the associated burner.

All fuel oil combustion: 120 lbs/Kgal

B. The default emission factors listed in IX.H.2.f.ii.A above apply until such time as stack testing is conducted as outlined in IX.H.1.e or by NSPS.

C. Compliance with the Source-wide NO_x Cap shall be determined for each day as follows:

Total daily NO_x emissions for emission points shall be calculated by adding the results of the NO_x equations for plant gas, fuel oil, and natural gas combustion listed below. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Plant Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMBTU)} * \text{Burner Heat Rating (BTU/hr)} * 24 \text{ hours per day} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/kgal)} * \text{Fuel Oil Consumption (kgal/day)} / (2,000 \text{ lb/ton})$$

Results shall be tabulated for each day; and records shall be kept which include

the meter readings (in the appropriate units), emission factors, and the calculated emissions.

iii. Source-wide SO₂ Cap

No later than January 1, 2019, the emission of SO₂ from all emission points (excluding routine SRU turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12-month period and 0.31 tons per day (tpd).

A. Setting of emission factors:

The emission factors listed below shall be applied to the relevant quantities of fuel combusted:

Natural gas - 0.60 lb SO₂/MMscf

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM which will measure the H₂S content of the fuel gas. The CEM shall operate as outlined in IX.H.1.f.

Fuel oil - The emission factor to be used in conjunction with fuel oil combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent, and the density of the fuel oil, as follows:

$$(\text{lb of SO}_2/\text{kgal}) = (\text{density lb/gal}) * (1000 \text{ gal/kgal}) * (\text{wt. \%S})/100 * (64 \text{ g SO}_2/32 \text{ g S})$$

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted.

B. Compliance with the Source-wide SO₂ Cap shall be determined for each day as follows:

Total daily SO₂ emissions shall be calculated by adding daily results of the SO₂ emissions equations listed below for natural gas, plant gas, and fuel oil combustion. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

The equations used to determine emissions are:

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Plant Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/kgal)} * \text{Fuel Oil Consumption (kgal/day)} / (2,000 \text{ lb/ton})$$

(kgal/24 hrs)/(2,000 lb/ton)

For purposes of these equations, fuel consumption shall be measured as outlined below:

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H₂S (averaged for each one-hour period), all meter reading (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

v. 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 23H1, 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)

1 g. Kennecott Utah Copper (KUC): Mine

2 i. Bingham Canyon Mine (BCM)

- 3
4 A. Maximum total mileage per calendar day for diesel-powered ore and waste haul trucks
5 shall not exceed 30,000 miles.

6
7 KUC shall keep records of daily total mileage for all periods when the mine is in
8 operation. KUC shall track haul truck miles with a Global Positioning System or
9 equivalent. The system shall use real time tracking to determine daily mileage.

- 10
11 B. To minimize fugitive dust on roads at the mine, the owner/operator shall
12 perform the following measures:

13
14 I. Apply water to all active haul roads as weather and operational conditions warrant
15 except during precipitation or freezing weather conditions, and shall apply a
16 chemical dust suppressant to active haul roads located outside of the pit influence
17 boundary no less than twice per year.

18
19 II. Chemical dust suppressant shall be applied as weather and operational conditions
20 warrant except during precipitation or freezing weather conditions on unpaved
21 access roads that receive haul truck traffic and light vehicle traffic.

22
23 III. Records of water and/or chemical dust control treatment shall be kept for all
24 periods when the BCM is in operation.

25
26 IV. KUC is subject to the requirements in the most recent federally approved Fugitive
27 Emissions and Fugitive Dust rules.

- 28
29 C. To minimize emissions at the mine, the owner/operator shall:

30
31 I. Control emissions from the in-pit crusher with a
32 baghouse.

33
34 ~~[D. Implementation Schedule~~

35
36 ~~KUC shall purchase new haul trucks with the highest engine Tier level available which~~
37 ~~meet mining needs. KUC shall maintain records of haul trucks purchased and retired]~~

38
39 ii. Copperton Concentrator (CC)

- 40
41 A. Control emissions from the Product Molybdenite Dryers with a scrubber during
42 operation of the dryers.

43
44 During operation of the dryers, the static pressure differential between the inlet and
45 outlet of the scrubber shall be within the manufacturer's recommended range and shall
46 be recorded weekly.

47
48 The manometer or the differential pressure gauge shall be calibrated according to the
49 manufacturer's instructions at least once per year.

h. Kennecott Utah Copper (KUC): Power Plant and Tailings Impoundment

i. Utah Power Plant

A. Boilers #1, #2, and #3 shall not operate.

B. Unit #5 shall not exceed the following emission rates to the atmosphere:

Pollutant	lb/hr	lb/event	ppmdv (15% O ₂ dry)
I. PM ₁₀ with duct firing: Filterable + condensable	18.8		
II. NO _x : Startup/shutdown		395	2.0
III. Startup / Shutdown Limitations:			
1. The total number of startups and shutdowns together shall not exceed 690 per calendar year.			
2. The NO _x emissions shall not exceed 395 lbs from each startup/shutdown event, which shall be determined using manufacturer data.			
3. Definitions:			
(i) Startup cycle duration ends when the unit achieves half of the design electrical generation capacity.			
(ii) Shutdown duration cycle begins with the initiation of turbine shutdown sequence and ends when fuel flow to the gas turbine is discontinued.			

C. Upon commencement of operation of Unit #5*, stack testing to demonstrate compliance with the emission limitations in IX.H.2.h.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 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.

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. PM ₁₀	every year

II. NO_x every year

D. The following requirements are applicable to Unit-#4 during the period November 1 to February 28/29 inclusive:

I. [Ø]During the period from November 1, to the last day in February inclusive,
only natural gas shall be used as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. The power plant 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. When burning natural gas the emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Pollutant	grains/dscf	ppmdv (3% O ₂)
68°F, 29.92 in. Hg		

1. PM₁₀ Units #1, #2, #3 and #4

filterable	0.004
------------	-------

filterable + condensable	0.03
-----------------------------	------

2. NO_x*

*NO_x emissions from Unit #4 are limited to the more stringent limit in Part H.12.k.i.

III. When using coal as a fuel during a curtailment of the natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Pollutant	grains/dscf	ppmdv (3% O ₂)
68°F, 29.92 in Hg		

4- Unit #4
(i) PM₁₀

filterable	0.029
------------	-------

filterable + condensable	0.29
-----------------------------	------

(ii) NO_x*

*NO_x emissions from Unit #4 are limited to the more stringent limit in Part H.12.k.i.

IV. If the units operated during the months specified above, stack testing to show

compliance with the emission limitations in H.2.h.i.D.II and III shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency	Initial Test
1. PM ₁₀	every year	#

Initial testing shall be performed when burning natural gas and also when burning coal as fuel. 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.

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

E. The following requirements are applicable to Unit #4 during the period March 1 to October 1 inclusive:

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

Pollutant	grains/dscf	ppmdv (3% O ₂)
68°F, 29.92 in Hg		
2. Unit #4		
(i) PM ₁₀ filterable	0.029	
(ii) NO _x *		[384]*

*NO_x emissions from Unit #4 are limited to the more stringent limit in Part H.12.k.i.

II. If the units operated during the months specified above, stack testing to show compliance with the emission limitations in H.2.h.i.E.I shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency
1. PM ₁₀	every year
2. NO _x	every year

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

F. The sulfur content of any fuel burned shall not exceed 0.66 lb of sulfur per million BTU per test.

- I. Coal increments will be collected using ASTM 2234, Type I conditions A, B, or C and systematic spacing.
- II. Percent sulfur content and gross calorific value of the coal on a dry basis will be determined for each gross sample using ASTM D methods 2013, 3177, 3173, and 2015.
- III. KUC shall measure at least 95% of the required increments in any one month that coal is burned in Unit #4.

ii. Tailings Impoundment

- A. No more than 50 contiguous acres or more than 5% of the total tailings area shall be permitted to have the potential for wind erosion.
 - I. Wind erosion potential is the area that is not wet, frozen, vegetated, crusted, or treated and has the potential for wind erosion.
 - II. KUC shall conduct wind erosion potential grid inspections monthly between February 15 and November 15. The results of the inspections shall be used to determine wind erosion potential.
 - III. If KUC or the Director of Utah Division of Air Quality (Director) determines that the percentage of wind erosion potential is exceeded, KUC shall meet with the Director, to discuss additional or modified fugitive dust controls/operational practices, and an implementation schedule for such, within five working days following verbal notification by either party.
- B. If between February 15 and November 15 KUC's daily weather forecast using surrounding area meteorological data is for a wind event (a wind event is defined as wind gusts exceeding 25 mph for more than one hour) the procedures listed below shall be followed within 48 hours of issuance of the forecast. KUC shall:
 - I. Alert the Utah Division of Air Quality promptly.
 - II. Continue surveillance and coordination of appropriate measures.
- C. KUC is subject to the requirements of the most recent federally approved Fugitive Emissions and Fugitive Dust rules.

i. Kennecott Utah Copper (KUC): Smelter & 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. PM₁₀
 - a. 89.5 lbs/hr (filterable)
 - b. 439 lbs/hr (filterable + condensable)
2. SO₂
 - a. 552 lbs/hr (3 hr. rolling average)
 - b. 422 lbs/hr (daily average)
3. NO_x
 - a. 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_x
 - a. 14.0 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 ₁₀	every year
	SO ₂	CEM
	NO _x	CEM
II. Holman Boiler	NO _x	every <u>three</u> years & CEMS or alternate method according to NSPS standards

C. 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.

1
2 ii. Refinery:
3

- 4 A. Emissions to the atmosphere from the indicated emission point shall not
5 exceed the following rate:
6
7

Emission Point	Pollutant	Maximum Emission Rate
The sum of two (Tankhouse) Boilers	NO _x	9.5 lbs/hr
Combined Heat Plant	NO _x	5.96 lbs/hr

- 8
9
10 B. Stack testing to show compliance with the above emission limitations
11 shall be performed as follows:
12

Emission Point	Pollutant	Testing Frequency
Tankhouse Boilers	NO _x	every <u>three years*</u>
Combined Heat Plant	NO _x	every year

13
14
15
16 *Stack testing shall be performed on boilers that have operated at least 300 hours
17 during a three-year period.
18

- 19 C. KUC must operate and maintain the stationary combustion turbine, air pollution
20 control equipment, and monitoring equipment in a manner consistent with good air
21 pollution control practices for minimizing emissions at all times including during
22 startup, shutdown, and malfunction.
23
24
25
26

1 j. PacifiCorp Energy: Gadsby Power Plant

2
3 i. Steam Generating Unit #1:

4 A. Emissions of NO_x shall be no greater than 179 lbs/hr on a three (3) hour block
5 average basis.

6
7 B. Emissions of NO_x shall not exceed 336 ppmvd (@ 3% O₂, dry)

8
9 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
10 CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x
11 limitation. The CEM shall operate as outlined in IX.H.1.f.

12
13 ii. Steam Generating Unit #2:

14 A. Emissions of NO_x shall be no greater than 204 lbs/hr on a three (3) hour block
15 average basis.

16
17 B. Emissions of NO_x shall not exceed 336 ppmvd (@ 3% O₂, dry)

18
19 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
20 continuous emission monitoring system (CEMS) consisting of NO_x and O₂
21 monitors to determine compliance with the NO_x limitation.

22
23 iii. Steam Generating Unit #3:

24 A. Emissions of NO_x shall be no greater than

25 I. 142 lbs/hr on a three (3) hour block average basis, applicable between November
26 1 and February 28/29

27 II. 203 lbs/hr on a three (3) hour block average basis, applicable between March 1
28 and October 31.

29
30 III. Emissions of NO_x shall not exceed 168 ppmvd (@ 3% O₂, dry), applicable
31 between November 1 and February 28/29.

32
33 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
34 CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x
35 limitation. The CEM shall operate as outlined in IX.H.1.f.

36
37 iv. Steam Generating Units #1-3:

38
39 A. The owner/operator shall use only natural gas as a primary fuel and No. 2 fuel
40 oil or better as back-up fuel in the boilers. The No. 2 fuel oil may be used only
41 during periods of natural gas curtailment and for maintenance firings.
42 Maintenance firings shall not exceed one-percent of the annual plant Btu
43 requirement. In addition, maintenance firings shall be scheduled between April
44 1 and November 30 of any calendar year. Records of fuel oil use shall be kept
45 and they shall show the date the fuel oil was fired, the duration in hours the fuel
46 oil was fired, the amount of fuel oil consumed during each curtailment, and the

1 reason for each firing.

2
3 v. Natural Gas-fired Simple Cycle, Catalytic-controlled Turbine Units:

4 A. Total emissions of NO_x from all three turbines shall be no greater than 600 lbs/day.

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

7
8 B. Emissions of NO_x from each turbine stack shall not exceed 5 ppmvd (@ 15% O₂ ,
9 dry). Emissions shall be calculated on a 30-day rolling average. This limitation
10 applies to steady state operation, not including startup and shutdown.

11
12 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
13 CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x
14 limitation. The CEM shall operate as outlined in IX.H.1.f.

15
16 vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

17
18 A. Startup begins when the fuel valves open and natural gas is supplied to the
19 combustion turbines

20
21 B. Startup ends when either of the following conditions is met:

22
23 I. The NO_x water injection pump is operational, the dilution air temperature is
24 greater than 600°F, the stack inlet temperature reaches 570°F, the ammonia
25 block valve has opened and ammonia is being injected into the SCR and the
26 unit has reached an output of ten (10) gross MW; or

27
28 II. The unit has been in startup for two (2) hours.

29
30 C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross
31 MW with the intent of removing the unit from service.

32
33 D. Shutdown ends at the cessation of fuel input to the turbine combustor.

34
35 E. Periods of startup or shutdown shall not exceed two (2) hours per combustion
36 turbine per day.

37
38 F. Turbine output (turbine load) shall be monitored and recorded on an hourly basis
39 with an electrical meter.

1 k. Tesoro Refining & Marketing Company

2
3 i. Source-wide PM₁₀ Cap

4 No later than January 1, 2019, combined emissions of PM₁₀ shall not exceed 2.25 tons
5 per day (tpd).

6
7 A. Setting of emission factors:

8
9 The emission factors derived from the most current performance test shall be
10 applied to the relevant quantities of fuel combusted. Unless adjusted by
11 performance testing as discussed in IX.H.2.k.i.B below, the default emission factors
12 to be used are as follows:

13
14 Natural gas:

15 Filterable PM₁₀: 0.0019 lb/MMBtu

16 Condensable PM₁₀: 0.0056 lb/MMBtu

17
18 Plant gas:

19 Filterable PM₁₀: 0.0019 lb/MMBtu

20 Condensable PM₁₀: 0.0056 lb/MMBtu

21
22 Fuel Oil: The PM₁₀ emission factor shall be determined from the latest edition of
23 AP-42 or other EPA-approved methods.

24
25 Cooling Towers: The PM₁₀ emission factor shall be determined from the latest
26 edition of AP-42 or other EPA-approved methods.

27
28 FCC Wet Scrubber:

29 The PM₁₀ emission factors shall be based on the most recent stack test and
30 verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

31
32 Where mixtures of fuel are used in a Unit, the above factors shall be
33 weighted according to the use of each fuel.

34
35 B. The default emission factors listed in IX.H.2.k.i.A above apply until such time as
36 stack testing is conducted as provided in IX.H.1.e or as outlined below:

37
38 Initial PM₁₀ stack testing on the FCC wet gas scrubber stack shall be conducted no
39 later than January 1, 2019 and at least [annually]once every three (3) years
40 thereafter. Stack testing shall be performed as outlined in IX.H.1.e.

41
42 Results from any stack testing performed at any other PM₁₀ sources in accordance
43 with IX.H.1.e shall be used where available.

44
45 C. Compliance with the Source-wide PM₁₀ Cap shall be determined for each
46 day as follows:

1
2 Total 24-hour PM₁₀ emissions for the emission points shall be calculated by adding
3 the daily results of the PM₁₀ emissions equations listed below for natural gas, plant
4 gas, and fuel oil combustion. These emissions shall be added to the emissions
5 from the cooling towers and wet scrubber to arrive at a combined daily PM₁₀
6 emission total. For purposes of this subsection a “day” is defined as a period of 24-
7 hours commencing at midnight and ending at the following midnight.

8
9 Daily natural gas and plant gas consumption shall be determined through the
10 use of flow meters.

11
12 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
13 tanks that supply combustion sources.

14
15 The emissions for each emitting unit shall be calculated by multiplying the
16 hours of operation of a unit, feed rate to a unit, or quantity of each fuel
17 combusted at each affected unit by the associated emission factor and
18 summing the results.

19
20 ii. Source-wide NO_x Cap

21 No later than January 1, 2019, combined emissions of NO_x shall not exceed 2.3 tons per
22 day (tpd) and 475 tons per rolling 12-month period.

23
24 A. Setting of emission factors:

25
26 The emission factors derived from the most current performance test shall be
27 applied to the relevant quantities of fuel combusted. Unless adjusted by
28 performance testing as discussed in IX.H.2.k.ii.B below, the default emission
29 factors to be used are as follows:

30
31 Natural gas/refinery fuel gas combustion using: Low NO_x burners (LNB): 0.051
32 lbs/MMbtu

33 Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu

34 Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-
35 approved methods.

36
37 B. The default emission factors listed in IX.H.2.k.ii.A above apply until such time as
38 stack testing is conducted as provided in IX.H.1.e or as outlined below:

39
40 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment
41 above 100 MMBtu/hr has already been performed and shall be conducted at least
42 [annually]once every three (3) years following the date of the last test. At that time a
43 new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived.
44 Stack testing shall be performed as outlined in IX.H.1.e. Stack testing is not required
45 for natural gas/refinery fuel gas combustion equipment with a NO_x CEMS.
46

C. Compliance with the source-wide NO_x Cap shall be determined for each day as follows:

Total 24-hour NO_x emissions shall be calculated by adding the emissions for each emitting unit. The emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor, and summing the results.

A NO_x CEM shall be used to calculate daily NO_x emissions from the FCCU wet gas scrubber stack. Emissions shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by the flow rate of the flue gas. The NO_x concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

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

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO₂ Cap

No later than January 1, 2019, combined emissions of SO₂ shall not exceed 3.8 tons per day (tpd) and 300 tons per rolling 12-month period.

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. The default emission factors to be used are as follows:

Natural gas: EF = 0.0006 lb/MMBtu

Propane: EF = 0.0006 lb/MMBtu

Diesel fuel: shall be determined from the latest edition of AP-42

Plant fuel gas: the emission factor shall be calculated from the H₂S measurement or from the SO₂ measurement obtained by direct testing/monitoring.

Where mixtures of fuel are used in a unit, the above factors shall be weighted according to the use of each fuel.

1
2 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
3 follows: Total daily SO₂ emissions shall be calculated by adding the daily SO₂
4 emissions for natural gas, plant fuel gas, and propane combustion to those from the
5 wet gas scrubber stack, and SRU.

6
7 Daily SO₂ emissions from the FCCU wet gas scrubber stack shall be determined
8 by multiplying the SO₂ concentration in the flue gas by the flow rate of the flue
9 gas. The SO₂ concentration in the flue gas shall be determined by a CEM as
10 outlined in IX.H.1.f.

11
12 SRUs: The emission rate shall be determined by multiplying the sulfur dioxide
13 concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide
14 concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f

15
16 Daily SO₂ emissions from other affected units shall be determined by multiplying
17 the quantity of each fuel used daily at each affected unit by the appropriate emission
18 factor.

19
20 Daily natural gas and plant gas consumption shall be determined through the
21 use of flow meters.

22
23 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
24 tanks that supply combustion sources.

25
26 Results shall be tabulated for each day, and records shall be kept which include
27 CEM readings for H₂S (averaged for each one-hour period), all meter reading (in
28 the appropriate units), fuel oil parameters (density and wt% sulfur for each day any
29 fuel oil is burned), and the calculated emissions.

30
31 C. Instead of complying with Condition IX.H.1.g.ii.A, sources may reduce the H₂S
32 content of the refinery plant gas to 60 ppm or less or reduce SO₂ concentration
33 from fuel gas combustion devices to 8 ppmvd at 0% O₂ or less as described in 40
34 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The
35 owner/operator shall comply with the fuel gas or SO₂ emissions monitoring
36 requirements of 40 CFR 60.107a and the related recordkeeping and reporting
37 requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have
38 the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used
39 interchangeably.

40
41 iv. SO₂ emissions from the SRU/TGTU/TGI shall be limited to:

42
43 B. 1.68 tons per day (tpd) for up to 21 days per rolling 12-month period, and

44
45 C. 0.69 tpd for the remainder of the rolling 12-month period.

D. 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.1.f

v. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

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 / CO Boiler	Wet Gas Scrubber, LoTOx
Furnace F-1	Ultra Low NOx Burners
Tanks	Tank Degassing Controls
North and South Flares	Flare Gas Recovery
Furnace H-101	Ultra Low NOx Burners
Truck loading rack	Vapor recovery unit
Sulfur recovery unit	Tail Gas Treatment Unit
API separator	Floating roof (single seal)

1 l. University of Utah: University of Utah Facilities

- 2
3 i. Emissions to the atmosphere from the listed emission points in Building 303 shall
4 not exceed the following concentrations:

5
6
7

Emission Point	Pollutant	ppmdv (3% O ₂ dry)
A. Boiler #4*	NO _x	187
B. Boilers #6 & #7.	NO _x	9
C. Boilers #9*.	NO _x	9
D. Turbine	NO _x	9
E. Turbine and WHRU Duct burner	NO _x	15

8
9 *By December 31, 2019, Boiler #4 will be decommissioned and Boiler #9 will be
10 installed and operational.

- 11
12
13 ii. Testing to show compliance with the emissions limitations of Condition i above
14 shall be performed as specified below:

15
16
17
18

Emission Point	Pollutant	Initial Test	Test Frequency
A. Boiler #4	NO _x	*	[every year] #
B. Boilers #6 & #7	NO _x	2018	[every year] #
C. Boilers #9	NO _x	2020	[every year] #
D. Turbine	NO _x	*	[every year] #
E. Turbine and WHRU Duct burner	NO _x	*	[every year] #

19
20 * Initial tests have been performed and the next method test using EPA approved
21 test methods shall be performed ~~[annually]~~within three (3) years of the last
22 stack test.

23
24
25 # A compliance test shall be performed at least once ~~[annually]~~every three years
26 from the date of the last compliance test that demonstrated compliance with the
27 emission limit(s). Compliance testing shall be performed using EPA approved
28 test methods acceptable to the Director. The Director shall be notified, in

1 accordance with all applicable rules, of any compliance test that is to be
2 performed. Beginning January 2018, annual screening with a portable monitor
3 must be conducted in those years that a compliance test is not performed.
4 Screening with a portable monitor shall be performed in accordance with the
5 portable monitor manufacturer's specifications. If screening with a portable
6 monitor indicates a potential exceedance of the concentration limit, a
7 compliance test must be performed within 90 days of that screening. Records
8 shall be kept on site which indicate the date, time, and results of each screening
9 and demonstrate that the portable monitor was operated in accordance with
10 manufacturer's specifications.
11
12

1 m. Utah Municipal Power Association: West Valley Power Plant.
2

3 i. Total emissions of NO_x from all five (5) turbines combined shall be no greater than
4 1050 lb of NO_x on a daily basis. For purposes of this subpart, a "day" is defined as a
5 period of 24- hours commencing at midnight and ending at the following midnight.
6

7 ii. Emissions of NO_x shall not exceed 5ppmdv (@ 15% O₂, dry) on a 30-day rolling
8 average.
9

10 iii. Total emissions of NO_x from all five (5) turbines shall include the sum of all periods in
11 the day including periods of startup, shutdown, and maintenance.
12

13 iv. The NO_x emission rate (lb/hr) shall be determined by CEM. The CEM shall
14 operate as outlined in IX.H.1.f

H.4 Interim Emission Limits and Operating Practices

- a. The terms and conditions of this Subsection IX.H.4 shall apply to the sources listed in this section on a temporary basis, as a bridge between the 1991 PM₁₀ State Implementation Plan and this PM₁₀ Maintenance Plan. For all other point sources listed in IX.H.2 and IX.H.3 the limits apply upon approval by the Utah Air Quality Board of the PM₁₀ Maintenance Plan. These bridge requirements are needed to impose limits on the sources that have time delays for implementation of controls. During this timeframe, the sources listed in this section may not meet the established limits listed in IX.H.1 and IX.H.2. As the control technology for the sources listed in this section is installed and operational, the terms and conditions listed in IX.H.1 and IX.H.2 become applicable and those limits replace the limits in this subsection. In no case, shall the terms and conditions listed in this Subsection IX.H.4 extend beyond January 1, 2019.

b. Petroleum Refineries:

- i. All petroleum refineries in or affecting the PM₁₀ nonattainment/maintenance area shall, for the purpose of this PM₁₀ Maintenance Plan:

A. Achieve an emission rate equivalent to no more than 9.8 kg of SO₂ per 1,000 kg of coke burn- off from any Catalytic Cracking unit by use of low-SO_x catalyst or equivalent emission reduction techniques or procedures, including those outlined in 40 CFR 60, Subpart J. Unless otherwise specified in IX.H.2, compliance shall be determined for each day based on a rolling seven-day average.

B. Compliance Demonstrations.

- I. Compliance with the maximum daily (24-hr) plant-wide emission limitations for PM₁₀, SO₂, and NO_x shall be determined by adding the calculated emission estimates for all fuel burning process equipment to those from any stack-tested or CEM-measured source components. NO_x and PM₁₀ emission factors shall be determined from AP-42 or from test data.

For SO_x, the emission factors are:

Natural gas: EF = 0.60 lb/MMscf

Propane: EF = 0.60 lb/MMscf

Plant gas: the emission factor shall be calculated from the H₂S measurement required in IX.H.1.g.ii.A.

Fuel oils (when permitted): The emission factor shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent, and the density of the fuel oil, as follows:

$$EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt.\% S/100} * (64 \text{ lb SO}_2\text{/32 lb S)}$$

Where mixtures of fuel are used in an affected unit, the above factors shall be weighted according to the use of each fuel.

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- II. Daily emission estimates for stack-tested source components shall be made by multiplying the latest stack-tested hourly emission rate times the logged hours of operation (or other relevant parameter) for that source component for each day. This shall not preclude a source from determining emissions through the use of a CEM that meets the requirements of R307-170.

1 c. Big West Oil Company

2 i. PM₁₀ Emissions

3 A. Combined emissions of filterable PM₁₀ from all external combustion process
4 equipment shall not exceed the following:

5
6 I. 0.377 tons per day, between October 1 and March 31;

7
8 II. 0.407 tons per day, between April 1 and September 30.

9
10 B. Emissions shall be determined for each day by multiplying the appropriate emission
11 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
12 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
13 results for the group of affected units.

14
15 The daily primary PM₁₀ contribution from the Catalyst Regeneration System
16 shall be calculated using the following equation:

17
18
$$\text{Emitted PM}_{10} = (\text{Feed rate to FCC in kbbbl/time}) * (22 \text{ lbs/kbbbl})$$

19
20 wherein the emission factor (22 lbs/kbbbl) may be re-established by stack testing.

21 Total 24-hour PM₁₀ emissions shall be calculated by adding the daily emissions from
22 the external combustion process equipment to the estimate for the Catalyst
23 Regeneration System.

24
25 ii. SO₂ Emissions

26
27 A. Combined emissions of sulfur dioxide from all external combustion process
28 equipment shall not exceed the following:

29
30 I. 2.764 tons/day, between October 1 and March 31;

31
32 II. 3.639 tons/day, between April 1 and September 30.

33
34 B. Emissions shall be determined for each day by multiplying the appropriate emission
35 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
36 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
37 results for the group of affected units.

38
39 The daily SO₂ emission from the Catalyst Regeneration System shall be
40 calculated using the following equation:

41
42
$$\text{SO}_2 = [43.3 \text{ lb SO}_2/\text{hr} / 7,688 \text{ bbl feed/day}] \times [(\text{operational feed rate in bbl/day}) \times$$

43
$$(\text{wt\% sulfur in feed} / 0.1878 \text{ wt\%}) \times (\text{operating hr/day})]$$

The FCC feed weight percent sulfur concentration shall be determined by the refinery laboratory every 30 days with one or more analyses. Alternatively, SO₂ emissions from the Catalyst Regeneration System may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

Emissions from the SRU Tail Gas Incinerator (TGI) shall be determined for each day by multiplying the sulfur dioxide concentration in the flue gas by the mass flow of the flue gas.

Total 24-hour SO₂ emissions shall be calculated by adding the daily emissions from the external combustion process equipment to the values for the Catalyst Regeneration System and the SRU.

iii. NO_x Emissions

A. Combined emissions of NO_x from all external combustion process equipment shall not exceed the following:

I. 1.027 tons per day, between October 1 and March 31;

II. 1.145 tons per day, between April 1 and September 30.

B. Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

The daily NO_x emission from the Catalyst Regeneration System shall be calculated using the following equation:

$$\text{NO}_x = (\text{Flue Gas, moles/hr}) \times (180 \text{ ppm} / 1,000,000) \times (30.006 \text{ lb/mole}) \times (\text{operating hr/day})$$

wherein the scalar value (180 ppm) may be re-established by stack testing. Alternatively, NO_x emissions from the Catalyst Regeneration System may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

Total 24-hour NO_x emissions shall be calculated by adding the daily emissions from gas-fired compressor drivers and the external combustion process equipment to the value for the Catalyst Regeneration System.

d. Chevron Products Company

i. PM₁₀ Emissions

- A. Combined emissions of filterable PM₁₀ from all external combustion process equipment shall be no greater than 0.234 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

ii. SO₂ Emissions

- A. Combined emissions of sulfur dioxide from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator, shall not exceed 0.5 tons/day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Alternatively, SO₂ emissions from the FCC CO Boiler and Catalyst Regenerator may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iii. NO_x Emissions

- A. Combined emissions of NO_x from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator and the SRU Tail Gas Incinerator, shall be no greater than 2.52 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Alternatively, NO_x emissions from the FCC CO Boiler and Catalyst Regenerator may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

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- iv. Chevron shall be permitted to combust HF alkylation polymer oil in its Alkylation unit.

1 e. Holly Refining and Marketing Company

2
3 i. PM₁₀ Emissions

- 4
5 A. Combined emissions of filterable PM₁₀ from all combustion sources, shall be no
6 greater than 0.44 tons per day.

7
8 Emissions shall be determined for each day by multiplying the appropriate emission
9 factor from section IX.H.4.b.i.B, or from testing as described below, by the relevant
10 parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each
11 affected unit, and summing the results for the group of affected units.

12
13 ii. SO₂ Emissions

- 14
15 A. Combined emissions of SO₂ from all sources shall be no greater than 4.714 tons per
16 day.

17
18 Emissions shall be determined for each day by multiplying the appropriate emission
19 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
20 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
21 results for the group of affected units.

22
23 Emissions from the FCC wet scrubbers shall be determined using a Continuous
24 Emissions Monitor (CEM) in accordance with IX.H.1.f.

25
26 iii. NO_x Emissions:

- 27
28 A. Combined emissions of NO_x from all sources shall be no greater than 2.20 tons per
29 day.

30
31 Emissions shall be determined for each day by multiplying the appropriate emission
32 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
33 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
34 results for the group of affected units.

1 f. Tesoro Refining & Marketing Company

2
3 i. PM₁₀ Emissions

4
5 A. Combined emissions of filterable PM₁₀ from gas-fired compressor drivers and all
6 external combustion process equipment, including the FCC/CO Boiler (ESP), shall be no
7 greater than 0.261 tons per day.

8
9 Emissions for gas-fired compressor drivers and the group of external combustion
10 process equipment shall be determined for each day by multiplying the appropriate
11 emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of
12 operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing
13 the results for the group of affected units.

14
15 ii. SO₂ Emissions

16
17 A. Combined emissions of SO₂ from gas-fired compressor drivers and all external
18 combustion process equipment, including the FCC/CO Boiler (ESP), shall not exceed
19 the following:

20
21 I. November 1 through end of February: 3.699 tons/day.

22
23 II. . March 1 through October 31: 4.374 tons/day.

24
25 Emissions shall be determined for each day by multiplying the appropriate emission
26 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
27 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
28 results for the group of affected units.

29
30 Emissions from the ESP stack (FCC/CO Boiler) shall be determined by multiplying
31 the SO₂ concentration in the flue gas by the mass flow of the flue gas.

32
33 The SO₂ concentration in the flue gas shall be determined by a continuous
34 emission monitor (CEM).

35
36 iii. NO_x Emissions

37
38 A. Combined emissions of NO_x from gas-fired compressor drivers and all external
39 combustion process equipment shall be no greater than 1.988 tons per day.

40
41 Emissions shall be determined for each day by multiplying the appropriate emission
42 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed
43 rate, or quantity of fuel combusted) at each affected unit, and summing the results for

1 the group of affected units.

H.11. General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM_{2.5}

- a. Except as otherwise outlined in individual conditions of this Subsection IX.H.11 listed below, the terms and conditions of this Subsection IX.H.11 shall apply to all sources subsequently addressed in Subsection IX.H.12 and 13. Should any inconsistencies exist between these subsections, the source specific conditions listed in IX.H.12 and 13 shall take precedence.
- b. Definitions:
 - i. The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.
 - ii. Natural gas curtailment means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment.
- c. Recordkeeping and Reporting:
 - i. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request.
 - ii. Each source shall comply with all applicable sections of R307-150 Emission Inventories. iii. Each source shall submit a report of any deviation from the applicable requirements of this Subsection IX.H, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be submitted to the Director no later than 24-months following the deviation or earlier if specified by an underlying applicable requirement. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107.
- d. Emission Limitations:
 - i. All emission limitations listed in Subsections IX.H.12 and IX.H.13 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.12 and 13.
 - ii. All emission limitations of particulate matter (PM_{2.5}) listed in Subsections IX.H.12 and IX.H.13 include both filterable PM_{2.5} and condensable PM, unless otherwise specified in the source specific conditions listed in IX.H.12 and IX.H.13.
- e. Stack Testing:

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- i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.12 and 13 shall be performed in accordance with the following:
 - A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved testing methods acceptable to the Director. Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.
 - B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or EPA Test Method No. 19 "SO₂ Removal & PM, SO₂, NO_x Rates from Electric Utility Steam Generators" or other EPA-approved testing methods acceptable to the Director.
 - C. PM: 40 CFR 60, Appendix A, Methods 5, 5b, 5f, 17 or other EPA approved testing methods acceptable to the Director.
 - D. PM_{2.5}: 40 CFR 51, Appendix M, 201a and 202, or other EPA approved testing methods acceptable to the Director. The back half condensables shall be used for compliance demonstration as well as for inventory purposes. If a method other than 201a is used, the portion of the front half of the catch considered PM_{2.5} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.
 - E. SO₂: 40 CFR 60 Appendix A, Method 6C, or other EPA-approved testing methods acceptable to the Director.
 - F. NO_x: 40 CFR 60 Appendix A, Method 7E, or other EPA-approved testing methods acceptable to the Director.
 - G. VOC: 40 CFR 60 Appendix A, Method 25A or other EPA-approved testing methods acceptable to the Director.
 - H. Calculations: To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.
 - I. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director.
 - J. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher

1 production rate when necessary. Testing at no less than 90% of the higher rate shall
2 be conducted. A new maximum production rate (110% of the new rate) will then be
3 allowed if the test is successful. This process may be repeated until the maximum
4 allowable production rate is achieved.
5

6 f. Continuous Emission and Opacity Monitoring
7

8 i. For all continuous monitoring devices, the following shall apply:
9

10 A. Except for system breakdown, repairs, calibration checks, and zero and span
11 adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an
12 affected source shall continuously operate all required continuous monitoring
13 systems and shall meet minimum frequency of operation requirements as outlined
14 in R307-170 and 40 CFR 60.13. Flow measurement shall be in accordance with the
15 requirements of 40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75,
16 Appendix A.
17

18 B. The monitoring system shall comply with all applicable sections of R307-170; 40
19 CFR 13; and 40 CFR 60, Appendix B – Performance Specifications.
20

21 ii. Opacity observations of emissions from stationary sources shall be conducted in
22 accordance with 40 CFR 60, Appendix A, Method 9.
23

24 g. Petroleum Refineries.
25

26 i. Limits at Fluid Catalytic Cracking Units
27

28 A. FCCU SO₂ Emissions
29

30 I. Each owner or operator of an FCCU shall comply with an SO₂ emission limit
31 of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50
32 ppmvd @ 0% excess air on a 7-day rolling average basis.
33

34 II. Compliance with this limit shall be determined ~~[by following 40 C.F.R.~~
35 ~~§60.105a(g)]~~using a CEM in accordance with IX.H.11.f.
36

37 B. FCCU PM Emissions
38

39 I. Each owner or operator of an FCCU shall comply with an emission limit of 1.0
40 pounds PM per 1000 pounds coke burn-off.
41

42 II. Compliance with this limit shall be determined by following the stack test
43 protocol specified in 40 C.F.R. §60.106(b) to measure PM emissions on the
44 FCCU. Each owner operator shall conduct stack tests ~~[annually]~~once every
45 three (3) years at each FCCU.

1
2 III. No later than January 1, 2019, each owner or operator of an FCCU subject to
3 NSPS Ja shall install, operate and maintain a continuous parameter monitor
4 system (CPMS) to measure and record operating parameters from the FCCU and
5 control devices as per the requirements of 40 CFR 60.105a(b)(1). No later than
6 January 1, 2019, each owner or operator of an FCCU not subject to NSPS Ja
7 shall install, operate and maintain a continuous opacity monitoring system to
8 measure and record opacity from the FCCU as per the requirements of 40 CFR
9 63.1572(b) and comply with the opacity limitation as per the requirements of
10 Table 7 to Subpart UUU of Part 63[for determination of source-wide PM_{2.5}
11 emissions as per the requirements of 40 CFR 60.105a(b)(1)].
12

13 ii. Limits on Refinery Fuel Gas
14

15 A. All petroleum refineries in or affecting any PM_{2.5} nonattainment area or any PM₁₀
16 nonattainment or maintenance area shall reduce the H₂S content of the refinery plant
17 gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based
18 on a rolling average of 365 days. The owner/operator shall comply with the fuel gas
19 monitoring requirements of 40 CFR 60.107a and the related recordkeeping and
20 reporting requirements of 40 CFR 60.108a. As used herein, refinery “plant gas”
21 shall have the meaning of “fuel gas” as defined in 40 CFR 60.101a, and may be
22 used interchangeably.
23

24 B. For natural gas, compliance is assumed while the fuel comes from a public utility.
25

26 iii. Limits on Heat Exchangers
27

28 A. Each owner or operator shall comply with the requirements of 40 CFR 63.654
29 for heat exchange systems in VOC service. The owner or operator may elect to
30 use another EPA-approved method other than the Modified El Paso Method if
31 approved by the Director.
32

33 I. The following applies in lieu of 40 CFR 63.654(b): A heat exchange system is
34 exempt from the requirements in paragraphs 63.654(c) through (g) of this
35 section if it meets any one of the criteria in the following paragraphs (1)
36 through (2) of this section.
37

38 1. All heat exchangers that are in VOC service within the heat exchange
39 system that either:
40

41 a. Operate with the minimum pressure on the cooling water side at
42 least 35 kilopascals greater than the maximum pressure on the
43 process side; or
44

45 b. Employ an intervening cooling fluid, containing less than 10 percent by
46 weight of VOCs, between the process and the cooling water. This

1 intervening fluid must serve to isolate the cooling water from the process
2 fluid and must not be sent through a cooling tower or discharged. For
3 purposes of this section, discharge does not include emptying for
4 maintenance purposes.

- 5
6 2. The heat exchange system cools process fluids that contain less than 10
7 percent by weight VOCs (i.e., the heat exchange system does not contain
8 any heat exchangers that are in VOC service).
9

10 iv. Leak Detection and Repair Requirements
11

- 12 A. Each owner or operator shall comply with the requirements of 40 CFR 60.590a to
13 60.593a as soon as practicable.
14
15 B. For units complying with the Sustainable Skip Period, previous process unit
16 monitoring results may be used to determine the initial skip period interval
17 provided that each valve has been monitored using the 500 ppm leak definition.
18

19 v. Requirements on Hydrocarbon Flares
20

- 21 A. All hydrocarbon flares at petroleum refineries located in or affecting a PM_{2.5}
22 nonattainment area or any PM₁₀ nonattainment or maintenance area shall be
23 subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a–109a), if
24 not already subject under the flare applicability provisions of Ja.
25
26 B. No later than January 1, 2019, all major source petroleum refineries in or affecting
27 any PM_{2.5} nonattainment area or any PM₁₀ nonattainment or maintenance area
28 shall either 1) install and operate a flare gas recovery system designed to limit
29 hydrocarbon flaring produced from each affected flare during normal operations to
30 levels below the values listed in 40 CFR 60.103a(c), or 2) limit flaring during
31 normal operations to 500,000 scfd for each affected flare. Flare gas recovery is not
32 required for dedicated SRU flare and header systems, or HF flare and header
33 systems.
34

35 vi. Requirements on Tank Degassing
36

- 37 A. Beginning January 1, 2017, the owner or operator of any stationary tank of 40,000-
38 gallon or greater capacity and containing or last containing any organic liquid, with
39 a true vapor pressure equal or greater than 10.5 kPa (1.52 psia) at storage
40 temperature (see R307-324-4(1)) shall not allow it to be opened to the atmosphere
41 unless the emissions are controlled by exhausting VOCs contained in the tank
42 vapor-space to a vapor control device until the organic vapor concentration is 10
43 percent or less of the lower explosion limit (LEL).
44
45 B. These degassing provisions shall not apply while connecting or disconnecting
46 degassing equipment.

1
2 C. The Director shall be notified of the intent to degas any tank subject to the rule.
3 Except in an emergency situation, initial notification shall be submitted at least
4 three (3) days prior to degassing operations. The initial notification shall include:
5

6 I. Start date and time;
7

8 II. Tank owner, address, tank location, and applicable tank permit numbers;
9

10 III. Degassing operator's name, contact person, telephone number;
11

12 IV. Tank capacity, volume of space to be degassed, and materials stored;
13

14 V. Description of vapor control device.
15

16 vii. No Burning of Liquid Fuel Oil in Stationary Sources
17

18 A. No petroleum refineries in or affecting any PM_{2.5} nonattainment area or PM₁₀
19 nonattainment or maintenance area shall be allowed to burn liquid fuel oil in
20 stationary sources except during natural gas curtailments or as specified in the
21 individual subsections of Section IX, Part H.
22

23 B. The use of diesel fuel meeting the specifications of 40 CFR 80.510 in standby or
24 emergency equipment is exempt from the limitation of IX.H.11.g.vii.A above.
25

26 h. Catalytic Oxidation for VOC Control
27

28 i. Internal Combustion Engines
29

30 A. Emissions from each VOC catalytic-controlled IC engine shall be routed through the
31 oxidation catalyst system prior to being emitted to the atmosphere. The oxidation
32 catalyst system shall be installed and operated as outlined in 40 CFR 63.6625(e).
33

34 ii. Natural Gas Combustion Turbines
35

36 A. Emissions from each VOC catalytic-controlled combustion turbine shall be routed
37 through the oxidation catalyst system prior to being emitted to the atmosphere. The
38 oxidation catalyst system shall be installed and operated according to the
39 manufacturer's emission-related written instructions and in a manner consistent with
40 good air pollution control practice for minimizing emissions.

H.12. Source-Specific Emission Limitations in Salt Lake City – UT PM_{2.5} 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 PM_{2.5} 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 PM_{2.5} 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 PM_{2.5} 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 PM_{2.5} 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 PM_{2.5} 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 PM_{2.5} 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 PM_{2.5} level at the nearest real-time monitoring station on days when motor testing occur.
- 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:

a. Pollutant	ppmdv (3% O ₂ dry)
NO _x	9

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

c. Subsequent to initial compliance testing, stack testing is required ~~annually~~ every three years.

B. Building M-14

I. The two 25 MMBTU/hr boiler 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:

a. Pollutant	ppmdv (3% O ₂ dry)
NO _x	9

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

c. Subsequent to initial compliance testing, stack testing is required ~~annually~~ every three years.

1 b. Big West Oil Refinery

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3 i. Source-wide PM_{2.5}:

4 Following installation of the Flue Gas Blow Back Filter (FGF), but no later than
5 January 1, 2019, combined emissions of PM_{2.5} (filterable+condensable) shall not
6 exceed 0.29 tons per day and 72.5 tons per rolling 12-month period. No later than
7 January 1, 2019, Big West Oil shall conduct stack testing to establish the ratio of
8 filterable and condensable PM_{2.5} from the Catalyst Regeneration System.

9
10 A. Setting of emission factors:

11 The emission factors derived from the most current performance test shall be
12 applied to the relevant quantities of fuel combusted. Unless adjusted by
13 performance testing as discussed in IX.H.12.b.i.B below, the default emission
14 factors to be used are as follows:

15 Natural gas:

16 Filterable PM_{2.5}: 1.9 lb/MMscf

17 Condensable PM_{2.5}: 5.7 lb/MMscf

18 Plant gas:

19 Filterable PM_{2.5}: 1.9 lb/MMscf

20 Condensable PM_{2.5}: 5.7 lb/MMscf

21 Fuel Oil: The PM_{2.5} emission factors shall be determined from the latest edition
22 of AP-42 or other EPA-approved methods.

23 FCC Stacks: The PM_{2.5} emission factors shall be established by stack test.

24 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
25 according to the use of each fuel.

26 B. The default emission factors ~~[for the FCC]~~ listed in IX.H.12.b.i.A above
27 apply until such time as stack testing is conducted as provided in IX.H.11.e
28 or as outlined below:

29 PM_{2.5} stack testing on the FCC shall be performed initially no later than
30 January 1, 2019 and at least ~~[annually]~~ once every three (3) years thereafter.
31 Stack testing shall be performed as outlined in IX.H.11.e.

32 C. Compliance with the source-wide PM_{2.5} Cap shall be determined for each day
33 as follows: Total 24-hour PM_{2.5} emissions for the emission points shall be
34 calculated by adding the daily results of the PM_{2.5} emissions equations listed
35 below for natural gas, plant gas, and fuel oil combustion. These emissions shall
36 be added to the emissions from the FCC to arrive at a combined daily PM_{2.5}

1 emission total.

2
3 For purposes of this subsection a “day” is defined as a period of 24-hours
4 commencing at midnight and ending at the following midnight.

5
6 Daily gas consumption shall be measured by meters that can delineate the
7 flow of gas to the boilers, furnaces and the SRU incinerator.

8
9 The equation used to determine emissions from these units shall be as
10 follows: Emissions = Emission Factor (lb/MMscf) * Gas Consumption
11 (MMscf/24 hrs)/(2,000
12 lb/ton)

13
14 Daily fuel oil consumption shall be monitored by means of leveling gauges
15 on all tanks that supply combustion sources.

16
17 The daily PM_{2.5} emissions from the FCC shall be calculated using the following
18 equation: $E = FR * EF$

19
20 Where:

21 E = Emitted PM_{2.5}

22 FR = Feed Rate to Unit (kbbbl/day)

23 EF = emission factor (lbs/kbbl), established by the most recent stack test

24
25 Results shall be tabulated for each day, and records shall be kept which include
26 the meter readings (in the appropriate units) and the calculated emissions.

27
28 ii. Source-wide NO_x Cap

29 No later than January 1, 2019, combined emissions of NO_x shall not exceed 0.80 tons
30 per day (tpd) and 195 tons per rolling 12-month period.

31
32 A. Setting of emission factors:

33
34 The emission factors derived from the most current performance test shall be applied
35 to the relevant quantities of fuel combusted. Unless adjusted by performance testing
36 as discussed in IX.H.12.b.ii.B below, the default emission factors to be used are as
37 follows:

38
39 Natural gas: shall be determined from the latest edition of AP-42 or other EPA-
40 approved methods.

41 Plant gas: assumed equal to natural gas

42 Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-
43 approved methods.

44
45 Where mixtures of fuel are used in a Unit, the above factors shall be weighted

1 according to the use of each fuel.

- 2
- 3 B. The default emission factors ~~[for the FCC]~~ listed in IX.H.12.b.ii.A above apply until
- 4 such time as stack testing is conducted as provided in IX.H.11.e or as outlined
- 5 below:

6

7 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment

8 above 40 MMBtu/hr has been performed NO_x emissions for the FCC are monitored

9 with a continuous emission monitoring system. Refinery Boilers and heaters over 40

10 MMBtu/hr, but less than 100 MMBtu/hr, are in compliance with monitoring and work

11 practice standards of Subpart DDDD of Part 63.

- 12
- 13 C. Compliance with the source-wide NO_x Cap shall be determined for each day as
- 14 follows: Total 24-hour NO_x emissions shall be calculated by adding the emissions
- 15 for each emitting unit. The emissions for each emitting unit shall be calculated by
- 16 multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each
- 17 fuel combusted at each affected unit by the associated emission factor, and
- 18 summing the results.

19

20 Daily plant gas consumption at the furnaces, boilers and SRU incinerator shall be

21 measured by flow meters. The equations used to determine emissions shall be as

22 follows:

23

24
$$\text{NO}_x = \text{Emission Factor (lb/MMscf)} * \text{Gas Consumption (MMscf/24 hrs)} / (2,000$$

25 lb/ton)

26

27 Where the emission factor is derived from the fuel used, as listed in IX.H.12.b.ii.A

28 above Daily fuel oil consumption shall be monitored by means of leveling gauges

29 on all tanks that supply combustion sources.

30

31 The daily NO_x emissions from the FCC shall be calculated using a CEM as outlined

32 in IX.H.11.f

33

34 Total daily NO_x emissions shall be calculated by adding the results of the above NO_x

35 equations for natural gas and plant gas combustion to the estimate for the FCC.

36

37 For purposes of this subsection a “day” is defined as a period of 24-hours

38 commencing at midnight and ending at the following midnight.

39

40 Results shall be tabulated for each day, and records shall be kept which include the

41 meter readings (in the appropriate units) and the calculated emissions.

- 42
- 43 iii. Source-wide SO₂ Cap

44 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 0.60 tons per

45 day and 140 tons per rolling 12-month period.

1
2 A. Setting of emission factors:

3 The emission factors derived from the most current performance test shall be
4 applied to the relevant quantities of fuel combusted. The default emission factors
5 to be used are as follows:

6
7 Natural Gas - 0.60 lb SO₂/MMscf gas

8
9 Plant Gas: The emission factor to be used in conjunction with plant gas combustion
10 shall be determined through the use of a CEM as outlined in IX.H.11.f.

11
12 SRUs: The emission rate shall be determined by multiplying the sulfur
13 dioxide concentration in the flue gas by the flow rate of the flue gas. The
14 sulfur dioxide concentration in the flue gas shall be determined by CEM as
15 outlined in IX.H.11.f.

16
17 Fuel oil: The emission factor to be used for combustion shall be calculated based
18 on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or
19 EPA approved equivalent acceptable to the Director, and the density of the fuel
20 oil, as follows:

21
22
$$EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt. \% S/100} * (64 \text{ lb SO}_2\text{/32}$$

23 lbs)

24
25 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
26 according to the use of each fuel.

27
28 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
29 follows:

30 Total daily SO₂ emissions shall be calculated by adding the daily SO₂ emissions
31 for natural gas and plant fuel gas combustion, to those from the FCC and SRU
32 stacks.

33
34 The daily SO_x emissions from the FCC shall be calculated using a CEM as outlined
35 in IX.H.11.f

36
37 Daily natural gas and plant gas consumption shall be determined through the use
38 of flow meters.

39
40 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
41 tanks that supply combustion sources.

42
43 For purposes of this subsection a “day” is defined as a period of 24-hours
44 commencing at midnight and ending at the following midnight.
45

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H₂S (averaged for each day), all meter readings (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment

- A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

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. ~~Requirements on Hydrocarbon Flares~~

- ~~A. No later than January 1, 2021, routine flaring will be limited to 300,000 scfd for each affected flare.~~

~~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 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.

1 c. Chemical Lime Company (LHoist North America)

2
3 Lime Production Kiln

- 4
- 5 i. No later than January 1, 2019, or upon source start-up, whichever comes later, SNCR
- 6 technology shall be installed on the Lime Production Kiln.
- 7
- 8 a. Effective January 1, 2019, or upon source start-up, whichever comes later, NO_x
- 9 emissions shall not exceed 56 lb/hr. (3-hr rolling average)
- 10
- 11 b. Compliance with the above emissions limit shall be determined by stack
- 12 testing as outlined in Section IX Part H.11.e of this SIP.
- 13
- 14 ii. No later than January 1, 2019, or upon source start-up, whichever comes later, a
- 15 baghouse control technology shall be installed and operating on the Lime Production
- 16 Kiln.
- 17
- 18 a. Effective January 1, 2019, or upon source start-up, whichever comes later, PM
- 19 emissions shall not exceed 0.12 pounds per ton (lb/ton) of stone feed. (3-hr rolling
- 20 average)
- 21
- 22 b. Effective January 1, 2019, or upon source start-up, whichever comes later, PM_{2.5}
- 23 (filterable + condensable) emissions shall not exceed 1.5 lbs/ton of stone feed. (3-hr
- 24 rolling average)
- 25
- 26 c. Compliance with the above emission limits shall be determined by stack testing as
- 27 outlined in Section IX Part H.11.e of this SIP and in accordance with 40 CFR 63
- 28 Subpart AAAAAA.
- 29
- 30 iii. An initial compliance test is required no later than January 1, 2019 (if start-up occurs
- 31 on or before January 1, 2019) or within 180 days of source start-up (if start-up occurs
- 32 after January 1, 2019) ***All subsequent compliance testing shall be performed at least***
- 33 ***once annually based upon the date of the last compliance test.***
- 34
- 35 iv. Upon plant start-up kiln emissions shall be exhausted through the baghouse during all
- 36 startup, shutdown, and operations of the kiln.
- 37
- 38 v. Start-up/shut-down provisions for SNCR technology be as follows:
- 39
- 40
- 41 a. No ammonia or urea injection during startup until the combustion gases exiting
- 42 the kiln reach the temperature when NO_x reduction is effective, and
- 43
- 44 b. No ammonia or urea injection during shutdown.
- 45
- 46 c. Records of ammonia or urea injection shall be documented in an operations log.

- 1 The operations log shall include all periods of start-up/shut-down and subsequent
- 2 beginning and ending times of ammonia or urea injection which documents v.a
- 3 and v.b above.

1 d. Chevron Products Company - Salt Lake Refinery

2
3 i. Source-wide PM_{2.5} Cap

4
5 No later than January 1, 2019, combined emissions of PM_{2.5} (filterable+condensable)
6 shall not exceed 0.305 tons per day (tpd) and 110 tons per rolling 12-month period.
7

8 A. Setting of emission factors:

9 The emission factors derived from the most current performance test shall be
10 applied to the relevant quantities of fuel combusted. Unless adjusted by
11 performance testing as discussed in IX.H.12.f.i.B below, the default emission
12 factors to be used are as follows:
13

14 Natural gas:

15 Filterable PM_{2.5}: 1.9 lb/MMscf

16 Condensable PM_{2.5}: 5.7 lb/MMscf
17

18 Plant gas:

19 Filterable PM_{2.5}: 1.9 lb/MMscf

20 Condensable PM_{2.5}: 5.7 lb/MMscf
21

22 HF alkylation polymer: shall be determined from the latest edition of AP-42 (HF
23 alkylation polymer treated as fuel oil #6) or other EPA-approved methods.
24

25 Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-
26 approved methods.
27

28 FCC Stack:

29 The PM_{2.5} emission factors shall be based on the most recent stack test and verified
30 by parametric monitoring as outlined in IX.H.11.g.i.B.III
31

32 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
33 according to the use of each fuel.
34

35 B. The default emission factors listed in IX.H.12.f.i.A above apply until such time as
36 stack testing is conducted as provided in IX.H.11.e or as outlined below:
37

38 Initial PM_{2.5} stack testing on the FCC stack has been performed and shall be
39 conducted at least [annually]once every three (3) years from the date of the last
40 stack test. Stack testing shall be performed as outlined in IX.H.11.e.
41

42 C. Compliance with the source-wide PM_{2.5} Cap shall be determined for each day as
43 follows:
44

45 Total 24-hour PM_{2.5} emissions for the emission points shall be calculated by adding

the daily results of the PM_{2.5} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the FCC to arrive at a combined daily PM_{2.5} emission total.

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

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The equation used to determine emissions for the boilers and furnaces shall be as follows: Emissions = Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NO_x Cap

No later than January 1, 2019, combined emissions of NO_x shall not exceed 2.1 tons per day (tpd) and 766.5 tons per rolling 12-month period.

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.12.f.ii.B below, the default emission factors to be used are as follows:

Natural gas: shall be determined from the latest edition of AP-42 or other EPA-approved methods.

Plant gas: assumed equal to natural gas

Alkylation polymer: shall be determined from the latest edition of AP-42 (as fuel oil #6) or other EPA-approved methods.

Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-approved methods.

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

1
2 B. The default emission factors listed in IX.H.12.f.ii.A above apply until such time as
3 stack testing is conducted as provided in IX.H.11.e or as outlined below:
4

5 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment
6 above 100 MMBtu/hr has been performed and shall be conducted at least
7 [annually]once every three (3) years from the date of the last stack test. At that
8 time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be
9 derived for each combustion type listed in IX.H.12.f.ii.A above. Stack testing shall
10 be performed as outlined in IX.H.11.e.
11

12 C. Compliance with the source-wide NO_x Cap shall be determined for each day as
13 follows:
14

15 Total 24-hour NO_x emissions shall be calculated by adding the emissions for each
16 emitting unit. The emissions for each emitting unit shall be calculated by
17 multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each
18 fuel combusted at each affected unit by the associated emission factor, and
19 summing the results.
20

21 A NO_x CEM shall be used to calculate daily NO_x emissions from the FCC.
22 Emissions shall be determined by multiplying the nitrogen dioxide concentration in
23 the flue gas by the flow rate of the flue gas. The NO_x concentration in the flue gas
24 shall be determined by a CEM as outlined in IX.H.11.f.
25

26 For purposes of this subsection a “day” is defined as a period of 24-hours
27 commencing at midnight and ending at the following midnight.
28

29 Daily natural gas and plant gas consumption shall be determined through the use of
30 flow meters.
31

32 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
33 tanks that supply combustion sources.
34

35 Results shall be tabulated for each day, and records shall be kept which include the
36 meter readings (in the appropriate units) and the calculated emissions
37

38 iii. Source-wide SO₂
39

40 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 1.05 tons
41 per day (tpd) and 383.3 tons per rolling 12-month period.
42

43 A. Setting of emission factors:
44

45 The emission factors derived from the most current performance test shall be

1 applied to the relevant quantities of fuel combusted. The default emission factors to
2 be used are as follows:

3
4 FCC: The emission rate shall be determined by the FCC SO₂ CEM as outlined in
5 IX.H.11.f.

6
7 SRUs: The emission rate shall be determined by multiplying the sulfur dioxide
8 concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide
9 concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f.

10
11 Natural gas: EF = 0.60 lb/MMscf

12
13 Fuel oil & HF Alkylation polymer: The emission factor to be used for combustion
14 shall be calculated based on the weight percent of sulfur, as determined by ASTM
15 Method D-4294-89 or EPA-approved equivalent acceptable to the Director, and the
16 density of the fuel oil, as follows:

17
18
$$EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt.\% S/100} * (64 \text{ lb SO}_2\text{/32}$$

19
$$\text{lb S)}$$

20
21 Plant gas: the emission factor shall be calculated from the H₂S measurement
22 obtained from the H₂S CEM.

23
24 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
25 according to the use of each fuel.

26
27 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
28 follows: Total daily SO₂ emissions shall be calculated by adding the daily SO₂
29 emissions for natural gas and plant fuel gas combustion, to those from the FCC and
30 SRU stacks.

31
32 Daily natural gas and plant gas consumption shall be determined through the use of
33 flow meters.

34
35 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
36 tanks that supply combustion sources.

37
38 Results shall be tabulated for each day, and records shall be kept which include
39 CEM readings for H₂S (averaged for each one-hour period), all meter reading (in
40 the appropriate units), fuel oil parameters (density and wt% sulfur for each day any
41 fuel oil is burned), and the calculated emissions.

42
43 iv. Emergency and Standby Equipment and Alternative Fuels

44
45 A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in

standby or emergency equipment at all times.

B. HF alkylation polymer may be burned in the Alky Furnace (F-36017).

C. Plant coke may be burned in the FCC Catalyst Regenerator.

v. Compressor Engine Requirements

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

Engine Number	NO _x in ppmvd @ 0% O ₂
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 ~~annually~~ once every three years thereafter. Stack testing shall be performed as outlined in IX.H.11.e.

vi. Flare Calculation

A. Chevron's Flare #3 receives gases from its Isomerization unit, Reformer unit as well as its HF Alkylation Unit. The HF Alkylation Unit's flow contribution to Flare #3 will not be included in determining compliance with the flow restrictions set in IX.H.11.g.v.B

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
Boilers: 5, 6, 7	Low NO _x burners and flue gas recirculation (FGR)
Cooling Water Towers	High efficiency drift eliminators
Crude Furnaces F21001, F21002	Low NO _x burners
Crude Oil Loading	Vapor Combustion Unit (VCU)
FCC Regenerator Stack	Vacuum gas oil hydrotreater, Electrostatic precipitator (ESP) and cyclones
Flares: Flare 1, 2, 3	Flare gas recovery system
HDS Furnaces F64010, F64011	Low NO _x 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)

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 to 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 to 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 ~~annually~~ once every three years.

1
2
3
4

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

1 f. Hexcel Corporation: Salt Lake Operations

2
3 i. The following limits shall not be exceeded for fiber line
4 operations:

5
6 A. 5.50 MMscf of natural gas consumed per day.

7
8 B. 0.061 MM pounds of carbon fiber produced per day.

9
10 C. Compliance with each limit shall be determined by the following methods:

11
12 I. Natural gas consumption shall be determined by examination of natural
13 gas billing records for the plant and onsite pipe-line metering.

14
15 II. Fiber production shall be determined by examination of plant production records.

16
17 III. Records of consumption and production shall be kept on a daily basis for all
18 periods when the plant is in operation.

19
20 ii. After a shutdown and prior to startup of fiber lines 13 to 16, the line's
21 baghouse(s) and natural gas injection dual chambered regenerative thermal
22 oxidizer shall be started and remain in operation during production.

23
24 A. During fiber line production, the static pressure differential across the filter media
25 shall be within the manufacturer's recommended range and shall be recorded daily.

26
27 B. The manometer or the differential pressure gauge shall be calibrated according to the
28 manufacturer's instructions at least once every 12 months.

29
30 iii. Filter boxes will be installed on Fiber lines 13 and 14 to control PM_{2.5} emissions no
31 later than December 31, 2019.

32
33 iv. Ultra Low NO_x Burners with flue gas recirculation shall be installed on Fiber lines 3,
34 4, and 7 to control NO_x emissions no later than December 31, 2024.

35
36
37 A. Emission limitations for NO_x shall be as follows:

38
39 Concentration (ppm)

40
41 Fiber Line 3 9.0

42
43 Fiber Line 4 9.0

44
45 Fiber Line 7 9.0

1 B. Stack testing shall be performed at least once ~~annually~~ every (3) years based
2 upon the date of the last compliance test and at a time when PAN is not being
3 introduced into the burners.

4
5 v. De-NO_x Water Direct Fired Thermal Oxidizer (DFTO) shall be installed on Fiber
6 lines 13, 14, 15, and 16 to control NO_x emissions no later than December 31, 2024.

7
8 vi. After a shutdown and prior to startup of the fiber lines, the residence time and
9 temperature associated with the regenerative thermal-oxidation fume incinerators
10 and solvent-coating fume incinerators shall be started and remain in operation during
11 production.

12
13 A. Unless otherwise indicated, the carbon fiber production thermal-oxidation fume
14 incinerators the minimum temperature shall be 1,400 deg F and the residence time
15 shall be greater than or equal to 0.5 seconds

16
17 Solvent-coating fume incinerators the minimum temperature shall be 1,450 deg F
18 and the residence time shall be greater than or equal to 0.5 seconds

19
20 For fiber lines 6, 7, 8, 10, 11, 12, and the line associated with the Research and
21 Development Facility, the solvent coating fume incinerators temperature shall range
22 from 1,400 to 1,700 deg F and the residence time shall be greater than or equal to 1.0
23 second

24
25 Residence times shall be determined by:

26
27
$$R = V / Q_{\max}$$

28 Where

29 R = residence time

30 V = interior volume of the incinerator – ft³

31 Q_{max} = maximum exhaust gas flow rate – ft³/second
32

33 B. Incinerator temperatures shall be monitored with temperature sensing equipment
34 that is capable of continuous measurement and readout of the combustion
35 temperature. The readout shall be located such that an inspector/operator can at
36 any time safely read the output. The measurement shall be accurate within ± 25°F
37 at operating temperature. The measurement need not be continuously recorded.
38 All instruments shall be calibrated against a primary standard at least once every
39 180 days. The calibration procedure shall be in accordance with 40 CFR 60,
40 Appendix A, Method 2, paragraph 6.3, and 10.31, or use a type "K"
41 thermocouple.
42
43

g. Holly Corporation: Holly Refining & Marketing Company (Holly Refinery)

i. Source-wide PM_{2.5} Cap

No later than January 1, 2019, PM_{2.5} emissions (filterable + condensable) from all combustion sources shall not exceed 47.6 tons per rolling 12-month period and 0.134 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.12. [i]g.i.B below, the default emission factors to be used are as follows:

Natural gas or Plant gas:

non-NSPS combustion equipment: 7.65 lb PM_{2.5}/MMscf

NSPS combustion equipment: 0.52 lb PM_{2.5}/MMscf

Fuel oil:

The filterable PM_{2.5} emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

$$\text{PM}_{2.5} \text{ (lb/1000 gal)} = (10 * \text{wt. \% S}) + 3$$

The condensable PM_{2.5} emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.

FCC Wet Scrubbers:

The PM_{2.5} emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.11.g.i.B.III. As an alternative to a continuous parameter monitor system or continuous opacity monitoring system for PM emissions from any FCCU controlled by a wet gas scrubber, as required in Subsection IX.H.11.g.i.B.III, the owner/operator may satisfy the opacity monitoring requirements from its FCC Units with wet gas scrubbers through an alternate monitoring program as approved by the EPA and acceptable to the Director.

B. The default emission factors listed in IX.H.12. [i]g.i.A above apply until such time as stack testing is conducted as outlined below:

Initial stack testing on all NSPS combustion equipment shall be conducted no later than January 1, 2019 and at least ~~annually~~ once every three years thereafter. At that time a new flow-weighted average emission factor in terms of: lb PM_{2.5}/MMBtu shall be derived. Stack testing shall be performed as outlined in IX.H.11.e.

1 C. Compliance with the source-wide PM_{2.5} Cap shall be determined for each day as
2 follows: Total 24-hour PM_{2.5} emissions for the emission points shall be calculated
3 by adding the daily results of the PM_{2.5} emissions equations listed below for natural
4 gas, plant gas, and fuel oil combustion. These emissions shall be added to the
5 emissions from the wet scrubbers to arrive at a combined daily PM_{2.5} emission
6 total.

7
8 For purposes of this subsection a “day” is defined as a period of 24-hours
9 commencing at midnight and ending at the following midnight.

10
11 Daily natural gas and plant gas consumption shall be determined through the use of
12 flow meters on all gas-fueled combustion equipment.

13
14 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
15 tanks that supply fuel oil to combustion sources.

16
17 The equations used to determine emissions for the boilers and furnaces shall
18 be as follows:

19
20 Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural/Plant Gas
21 Consumption
22 (MMscf/day)/(2,000 lb/ton)

23
24 Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption
25 (kgal/day)/(2,000 lb/ton)

26
27 Results shall be tabulated for each day, and records shall be kept which include all
28 meter readings (in the appropriate units), and the calculated emissions.

29
30 ii. Source-wide NO_x Cap

31
32 No later than January 1, 2019, NO_x emissions into the atmosphere from all emission
33 points shall not exceed 347.1 tons per rolling 12-month period and 2.09 tons per day
34 (tpd).

35
36 A. Setting of emission factors:

37 The emission factors derived from the most current performance test shall be
38 applied to the relevant quantities of fuel combusted.

39
40 Unless adjusted by performance testing as discussed in IX.H.12. [i]g.ii.B below,
41 the default emission factors to be used are as follows:

42
43 Natural gas/refinery fuel gas combustion using:

44 Low NO_x burners (LNB): 41 lbs/MMscf

45 Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu

46 Next Generation Ultra Low NO_x burners (NGULNB): 0.10 lbs/MMbtu

Boiler #5: 0.02 lbs/MMbtu

All other boilers with selective catalytic reduction (SCR): 0.02 lbs/MMbtu

All other combustion burners: 100 lb/MMscf

Where:

"Natural gas/refinery fuel gas" shall represent any combustion of natural gas, refinery fuel gas, or combination of the two in the associated burner.

All fuel oil combustion: 120 lbs/Kgal

B. The default emission factors listed in IX.H.12. [k]g.ii.A above apply until such time as stack testing is conducted as outlined in IX.H.11.e or by NSPS.

C. Compliance with the Source-wide NO_x Cap shall be determined for each day as follows: Total daily NO_x emissions for emission points shall be calculated by adding the results of the NO_x equations for plant gas, fuel oil, and natural gas combustion listed below. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMBTU) * Burner Heat Rating (BTU/hr)*
24 hours per day /(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)

Results shall be tabulated for each day; and records shall be kept which include the meter readings (in the appropriate units), emission factors, and the calculated emissions.

iii. Source-wide SO₂ Cap

No later than January 1, 2019, the emission of SO₂ from all emission points (excluding routine SRU turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12- month period and 0.31 tons per day (tpd).

A. Setting of emission factors:

The emission factors listed below shall be applied to the relevant quantities of fuel combusted:

Natural gas - 0.60 lb SO₂/MMscf

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM which will measure the H₂S content of the fuel gas. The CEM shall operate as outlined in IX.H.11.f.

Fuel oil - The emission factor to be used in conjunction with fuel oil combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent, and the density of the fuel oil, as follows:

$$(\text{lb of SO}_2/\text{kgal}) = (\text{density lb/gal}) * (1000 \text{ gal/kgal}) * (\text{wt. \%S})/100 * (64 \text{ g SO}_2/32 \text{ g S})$$

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted.

- B. Compliance with the Source-wide SO₂ Cap shall be determined for each day as follows: Total daily SO₂ emissions shall be calculated by adding daily results of the SO₂ emissions equations listed below for natural gas, plant gas, and fuel oil combustion. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

The equations used to determine emissions are:

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Plant Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/kgal)} * \text{Fuel Oil Consumption (kgal/24 hrs)} / (2,000 \text{ lb/ton})$$

For purposes of these equations, fuel consumption shall be measured as outlined below: Daily natural gas and plant gas consumption shall be determined through

the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H₂S (averaged for each one-hour period), all meter reading (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

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 23H1, 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)

1 h. Kennecott Utah Copper (KUC): Mine

2
3 i. Bingham Canyon Mine (BCM)

- 4
5 A. Maximum total mileage per calendar day for diesel-powered ore and waste haul
6 trucks shall not exceed 30,000 miles.

7
8 KUC shall keep records of daily total mileage for all periods when the mine is in
9 operation. KUC shall track haul truck miles with a Global Positioning System or
10 equivalent. The system shall use real time tracking to determine daily mileage.

- 11
12 B. To minimize fugitive dust on roads at the mine, the owner/operator shall perform the
13 following measures:

- 14
15 I. Apply water to all active haul roads as weather and operational conditions
16 warrant except during precipitation or freezing weather conditions, and shall
17 apply a chemical dust suppressant to active haul roads located outside of the pit
18 influence boundary no less than twice per year.

- 19
20 II. Chemical dust suppressant shall be applied as weather and operational
21 conditions warrant except during precipitation or freezing weather conditions on
22 unpaved access roads that receive haul truck traffic and light vehicle traffic.

- 23
24 III. Records of water and/or chemical dust control treatment shall be kept for all
25 periods when the BCM is in operation.

- 26
27 IV. KUC is subject to the requirements in the most recent federally approved
28 Fugitive Emissions and Fugitive Dust rules.

- 29
30 C. The In-pit crusher baghouse shall not exceed a PM_{2.5} emission limit of 0.78
31 lbs/hr(0.007 gr/dscf) PM_{2.5} monitoring shall be performed by stack testing [annually]
32 every three years.

33
34 ~~[D. Minimum design payload per ore and waste haul truck shall not be less than 240~~
35 ~~tons. The minimum design payload for all trucks combined shall be an average of~~
36 ~~300 tons.]~~

37
38 ii. Copperton Concentrator (CC)

- 39
40 A. Control emissions from the Product Molybdenite Dryers with a scrubber during
41 operation of the dryers.

42
43 During operation of the dryers, the static pressure differential between the inlet and
44 outlet of the scrubber shall be within the manufacturer's recommended range and
45 shall be recorded weekly.

46
47 The manometer or the differential pressure gauge shall be calibrated according to the
48 manufacturer's instructions at least once per year.

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The remaining heaters shall not operate more than 300 hours per rolling 12- month period unless upgraded so the NOx 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. ~~During the period from November 1, to the last day in February inclusive,~~
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 68°F. 29.92 in Hg	ppmdv 3% O ₂	lbs/hr	lbs/MMBtu	lbs/event
1. PM _{2.5} :					
Filterable	0.004				
Filterable + condensable	0.03				

2. NO_x: ~~[20]~~30 ~~[17.0]~~32 ~~[0.02]~~0.04
Startup / Shutdown 395

III. ~~During the period from March 1 to October 31, Unit #4 shall use coal, natural gas, or oils as fuels.~~

IV. ~~When burning coal Unit #4 shall not exceed the following emission rates to the atmosphere:~~

Pollutant	grains/dscf 68°F. 29.92 in Hg	ppmdv 3% O ₂	lbs/MMBTU	lbs/event
1. PM _{2.5} :				
Filterable	0.029			
Filterable + Condensable	0.29			
2. NO _x		80	0.06	
Startup / Shutdown				395

~~* Except during startup and shutdown.~~

V. Startup / Shutdown Limitations:

- The total number of startups and shutdowns together shall not exceed 690 per calendar year.
- The NO_x emissions shall not exceed 395 lbs from each startup/shutdown event, which shall be determined using manufacturer data.

3. Definitions:

- (i) Startup cycle duration ends when the unit achieves half of the design electrical generation capacity.
- (ii) Shutdown duration cycle begins with the initiation of boiler shutdown and ends when fuel flow to the boiler is discontinued.

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. PM _{2.5}	every year
II. NO _x	every year

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

Pollutant	lbs/hr	lbs/event	ppmdv (15% O ₂ dry)
I. PM _{2.5} with duct firing: Filterable + condensable	18.8		
II. VOC:			2.0*
III. NO _x : Startup / Shutdown	395		2.0*

* Except during startup and shutdown.

IV. Startup / Shutdown Limitations:

- 1. The total number of startups and shutdowns together shall not exceed 690 per calendar year.
- 2. The NO_x emissions shall not exceed 395 lbs from each startup/shutdown event, which shall be determined using manufacturer data.

3. Definitions:

1 (i) Startup cycle duration ends when the unit achieves half of the design electrical
2 generation capacity.

3
4 (ii) Shutdown duration cycle begins with the initiation of boiler shutdown and ends
5 when fuel flow to the boiler is discontinued.

6
7 D: Upon commencement of operation of Unit #5*, stack testing to demonstrate
8 compliance with the emission limitations in IX.H.12.m.i.B shall be performed as
9 follows for the following air contaminants

10
11 * Initial compliance testing for the natural gas turbine and duct burner is required.
12 The initial test shall be performed within 60 days after achieving the maximum heat
13 input capacity production rate at which the affected facility will be operated and in no
14 case later than 180 days after the initial startup of a new emission source.

15
16 The limited use of natural gas during maintenance firings and break-in firings does
17 not constitute operation and does not require stack testing.

18
19

Pollutant	Test Frequency
I. PM _{2.5}	every year
II. NO _x	every year
III. VOC	every year

20
21
22
23

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. PM_{2.5}
 - 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. NO_x 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 <u>three</u> years and CEMS or alternate method according to applicable NSPS standards

The Holman boiler shall use an EPA approved test method [annually]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
The sum of two (Tankhouse) Boilers	NO _x	9.5 lbs/hr (before December 2020)
(Upgraded Tankhouse Boiler)	NO _x	1.5 lbs/hr (After December 2020)
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
Upgraded Tankhouse Boilers	NO _x	every <u>three years*</u>
Combined Heat Plant	NO _x	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 NO_x 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 NO_x 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.

1 k. Nucor Steel Mills

- 2
3 i. Emissions to the atmosphere from the indicated emission points shall not exceed the
4 following rates:

5
6 A. Electric Arc Furnace Baghouse

7
8 I. PM_{2.5}

- 9 1. 17.4 lbs/hr (24 hr. average filterable)
10 2. 29.53 lbs/hr (24 hr. average condensable)

11
12 II. SO₂

- 13 1. 93.98 lbs/hr (3 hr. rolling average)
14 2. 89.0 lbs/hr (daily average)

15
16 III. NO_x 59.5 lbs/hr (calendar-day average)

17
18 IV. VOC 22.20 lbs/hr

19
20 B. Reheat Furnace #1

21 NO_x 15.0 lb/hr

22
23 C. Reheat Furnace #2

24 NO_x 8.0 lb/hr

- 25
26 ii. Stack testing to show compliance with the emissions limitations of Condition (i)
27 above shall be performed as outlined in IX.H.11.e and as specified below:

28	EMISSION POINT	POLLUTANT	TEST FREQUENCY
29			
30			
31	A. Electric Arc Furnace Baghouse	PM _{2.5}	every year
32		SO ₂	CEM
33		NO _x	CEM
34		VOC	every year
35			
36	B. Reheat Furnace #1	NO _x	every year
37			
38	C. Reheat Furnace #2	NO _x	every year

39
40 iii. Testing Status (To be applied to (i) and (ii) above)

- 41
42 A. To demonstrate compliance with the Electric Arc Furnace stack mass emissions
43 limits for SO₂ and NO_x of Condition (i)(A) above, Nucor shall calibrate, maintain
44 and operate the measurement systems for continuously monitoring for SO₂ and NO_x
45 concentrations and stack gas volumetric flow rates in the Electric Arc Furnace stack.
46 Such measurement systems shall meet the requirements of R307-170.

- 1 B. For PM_{2.5} testing, 40 CFR 60, Appendix A, Method 5D, or another EPA approved
2 method acceptable to the Director, shall be used to determine total TSP emissions. If
3 TSP emissions are below the PM_{2.5} limit, that will constitute compliance with the
4 PM_{2.5} limit. If TSP emissions are not below the PM_{2.5} limit, the owner/operator shall
5 retest using EPA approved methods specified for PM_{2.5} testing, within 120 days.
- 6
7 C. Startup/shutdown NO_x and SO₂ emissions are monitored by CEMS.

1 I. PacifiCorp Energy: Gadsby Power Plant

2
3 i. Steam Generating Unit #1:

4
5 A. Emissions of NO_x shall be no greater than 179 lbs/hr on a three (3) hour block
6 average basis.

7
8 B. Emissions of NO_x shall not exceed 336 ppmdv (@ 3% O₂, dry)

9
10 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
11 CEM consisting of NO_x and O₂ monitors to determine compliance with the
12 NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

13
14 ii. Steam Generating Unit #2:

15
16 A. Emissions of NO_x shall be no greater than 204 lbs/hr on a three (3) hour block
17 average basis.

18
19 B. Emissions of NO_x shall not exceed 336 ppmdv (@ 3% O₂, dry)

20
21 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
22 continuous emission monitoring system (CEMS) consisting of NO_x and O₂
23 monitors to determine compliance with the NO_x limitation.

24
25 iii. Steam Generating Unit #3:

26 A. Emissions of NO_x shall be no greater than

27
28 I. 142 lbs/hr on a three (3) hour block average basis, applicable between
29 November 1 and February 28/29.

30
31 II. 203 lbs/hr on a three (3) hour block average basis, applicable between March
32 1 and October 31.

33
34 B. Emissions of NO_x shall not exceed

35
36 I. 168 ppmdv (@ 3% O₂, dry), applicable between November 1 and February
37 28/29

38
39 II. 168 ppmdv (@ 3% O₂, dry), applicable between applicable between March 1
40 and October 31.

41
42 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
43 CEM consisting of NO_x and O₂ monitors to determine compliance with the
44 NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

45
46 iv. Steam Generating Units #1-3:

- 1
- 2 A. The owner/operator shall use only natural gas as a primary fuel and No. 2 fuel oil or
- 3 better as back-up fuel in the boilers. The No. 2 fuel oil may be used only during
- 4 periods of natural gas curtailment and for maintenance firings. Maintenance firings
- 5 shall not exceed one-percent of the annual plant Btu requirement. In addition,
- 6 maintenance firings shall be scheduled between April 1 and November 30 of any
- 7 calendar year. Records of fuel oil use shall be kept and they shall show the date the
- 8 fuel oil was fired, the duration in hours the fuel oil was fired, the amount of fuel oil
- 9 consumed during each curtailment, and the reason for each firing.
- 10
- 11 v. Natural Gas-fired Simple Cycle, Catalytic-controlled Turbine Units:
- 12
- 13 A. Total emissions of NO_x from all three turbines shall be no greater than 600
- 14 lbs/day. For purposes of this subsection a “day” is defined as a period of 24-hours
- 15 commencing at midnight and ending at the following midnight.
- 16
- 17 B. Emissions of NO_x from each turbine stack shall not exceed 5 ppmvd (@ 15% O₂
- 18 dry). Emissions shall be calculated on a 30-day rolling average. This limitation
- 19 applies to steady state operation, not including startup and shutdown.
- 20
- 21 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
- 22 CEM consisting of NO_x and O₂ monitors to determine compliance with the
- 23 NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.
- 24
- 25 vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan
- 26
- 27 A. Startup begins when the fuel valves open and natural gas is supplied to the
- 28 combustion turbines
- 29
- 30 B. Startup ends when either of the following conditions is met:
- 31
- 32 I. The NO_x water injection pump is operational, the dilution air temperature is
- 33 greater than 600°F, the stack inlet temperature reaches 570°F, the ammonia
- 34 block value has opened and ammonia is being injected into the SCR and the
- 35 unit has reached an output of ten (10) gross MW; or
- 36
- 37 II. The unit has been in startup for two (2) hours.
- 38
- 39 C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross
- 40 MW
- 41 with the intent of removing the unit from service.
- 42
- 43 D. Shutdown ends at the cessation of fuel input to the turbine combustor.
- 44
- 45 E. Periods of startup or shutdown shall not exceed two (2) hours per combustion
- 46 turbine per day.

1
2
3

- F. Turbine output (turbine load) shall be monitored and recorded on an hourly basis with an electrical meter.

1 m. Tesoro Refining and Marketing Company: Salt Lake City Refinery

2
3 i. Source-wide PM_{2.5} Cap

4
5 No later than January 1, 2019, combined emissions of PM_{2.5} (filterable+condensable)
6 shall not exceed 2.25 tons per day (tpd) and 179 tons per rolling 12-month period.
7

8 A. Setting of emission factors:

9
10 The emission factors derived from the most current performance test shall be
11 applied to the relevant quantities of fuel combusted. Unless adjusted by
12 performance testing as discussed in IX.H.12.p.i.B below, the default emission
13 factors to be used are as follows:
14

15 Natural gas:

16 Filterable PM_{2.5}: 0.0019 lb/MMBtu

17 Condensable PM_{2.5}: 0.0056 lb/MMBtu
18

19 Plant gas:

20 Filterable PM_{2.5}: 0.0019 lb/MMBtu

21 Condensable PM_{2.5}: 0.0056 lb/MMBtu
22

23 Fuel Oil: The PM_{2.5} emission factor shall be determined from the latest edition of
24 AP-42 or other EPA-approved methods.
25

26 FCC Wet Scrubber:

27 The PM_{2.5} emission factors shall be based on the most recent stack test and verified
28 by parametric monitoring as outlined in IX.H.11.g.i.B.III
29

30 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
31 according to the use of each fuel.
32

33 B. The default emission factors listed in IX.H.12.m.i.A above apply until such time as
34 stack testing is conducted as provided in IX.H.11.e or as outlined below:
35

36 Initial PM_{2.5} stack testing on the FCC wet gas scrubber stack shall be conducted no
37 later than January 1, 2019 and at least [annually]once every three (3) years
38 thereafter. Stack testing shall be performed as outlined in IX.H.11.e.
39

40 C. Compliance with the Source-wide PM_{2.5} Cap shall be determined for each day as
41 follows: Total 24-hour PM_{2.5} emissions for the emission points shall be calculated
42 by adding the daily results of the PM_{2.5} emissions equations listed below for natural
43 gas, plant gas, and fuel oil combustion. These emissions shall be added to the
44 emissions from the wet scrubber to arrive at a combined daily PM_{2.5} emission total.
45 For purposes of this subsection a “day” is defined as a period of 24-hours
46 commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit feed rate to a unit, or quantity of each fuel combusted at each affected unity by the associated emission factor, and summing the results.

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NO_x Cap

No later than January 1, 2019, combined emissions of NO_x shall not exceed 2.3 tons per day (tpd) and 475 tons per rolling 12-month period.

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.12.m.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:

Low NO_x burners (LNB):0.051 lbs/MMbtu

Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu

Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-approved methods.

B. The default emission factors listed in IX.H.12.m.ii.A above apply unless stack testing results are available or emissions are measured by operation of a NO_x CEMS.

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has already been performed and shall be conducted at least [annually]once every three (3) years. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived. Stack testing shall be performed as outlined in IX.H.11.e. Stack testing is not required for natural gas/refinery fuel gas combustion equipment with a NO_x CEMS.

C. Compliance with the source-wide NO_x Cap shall be determined for each day as follows: Total 24-hour NO_x emissions shall be calculated by adding the emissions for each emitting unit. The emissions for each emitting unit shall be calculated by

1 multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each
2 fuel combusted at each affected unit by the associated emission factor, and
3 summing the results.
4

5 A NO_x CEM shall be used to calculate daily NO_x emissions from the FCCU wet
6 gas scrubber stack. Emissions shall be determined by multiplying the nitrogen
7 dioxide concentration in the flue gas by the flow rate of the flue gas. The NO_x
8 concentration in the flue gas shall be determined by a CEM as outlined in
9 IX.H.11.f.
10

11 Daily natural gas and plant gas consumption shall be determined through the use of
12 flow meters.
13

14 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
15 tanks that supply combustion sources.
16

17 For purposes of this subsection a “day” is defined as a period of 24-hours
18 commencing at midnight and ending at the following midnight.
19

20 Results shall be tabulated for each day, and records shall be kept which include the
21 meter readings (in the appropriate units) and the calculated emissions.
22

23 iii. Source-wide SO₂ Cap
24

25 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 3.8 tons per
26 day (tpd) and 300 tons per rolling 12-month period.
27

28 A. Setting of emission factors:
29

30 The emission factors derived from the most current performance test shall be
31 applied to the relevant quantities of fuel combusted. The default emission factors to
32 be used are as follows:
33

34 Natural gas: EF = 0.0006 lb/MMBtu

35 Propane: EF = 0.0006 lb/MMBtu

36 Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-
37 approved methods.
38

39 Plant fuel gas: the emission factor shall be calculated from the H₂S measurement or
40 from the SO₂ measurement obtained by direct testing/monitoring.
41

42 Where mixtures of fuel are used in a unit, the above factors shall be weighted
43 according to the use of each fuel.
44

45 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
46 follows: Total daily SO₂ emissions shall be calculated by adding the daily SO₂

emissions for natural gas, plant fuel gas, and propane combustion to those from the wet gas scrubber stack.

Daily SO₂ emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO₂ concentration in the flue gas by the flow rate of the flue gas. The SO₂ concentration in the flue gas shall be determined by a CEM as outlined in IX.H.11.f.

SRUs: The emission rate shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f

Daily SO₂ emissions from other affected units shall be determined by multiplying the quantity of each fuel used daily at each affected unit by the appropriate emission factor.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H₂S (averaged for each one-hour period), all meter reading (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

- C. Instead of complying with Condition IX.H.11.g.ii.A, source may reduce the H₂S content of the refinery plant gas to 60 ppm or less or reduce SO₂ concentration from fuel gas combustion devices to 8 ppmvd at 0% O₂ or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas or SO₂ emissions monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably.

iv. 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

v. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

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 / CO Boiler	Wet Gas Scrubber, LoTOx
Furnace F-1	Ultra Low NOx Burners
Tanks	Tank Degassing Controls
North and South Flares	Flare Gas Recovery
Furnace H-101	Ultra Low NOx Burners
Truck loading rack	Vapor recovery unit
Sulfur recovery unit	Tail Gas Treatment Unit
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:

Source: Paper Making Boilers (Each)

Pollutant	Oxygen Ref.	lb/hr
NO _x	3%	3.3
PM _{2.5} (Filterable and Condensables)	3%	0.9

Source: Paper Machine Process Stack

Pollutant	Oxygen Ref.	lb/hr
NO _x	3%	13.50
PM _{2.5} (Filterable and Condensables)	3%	17.95

Source: Utility Boilers (Each)

Pollutant	Oxygen Ref.	lb/hr
NO _x	3%	1.8
PM _{2.5} (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 [annually]at a minimum of once every three years.

ii. 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.

iii. 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

- 1 the cessation of natural gas flow to the dryer combustion equipment. Shutdown
- 2 conditions end within thirty (30) minutes of hot air being diverted to the dryer
- 3 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 ppm_{dv} (@ 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 O ₂ dry)	Pollutant	ppmdv (3%
Boiler #4*	NO _x	187
Boilers #6 & 7	NO _x	9
Boiler #9*	NO _x	9
Turbine	NO _x	9
Turbine and WHRU Duct burner	NO _x	15

*[Boiler #4-B*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:

Emissions Point	Pollutant	Initial Test	Test Frequency
Boilers #4*	NO _x	*	[every year]#
Boilers #6 & 7	NO _x	*	[every year]#
Boiler #9*	NO _x	2020	[every year]#
Turbine	NO _x	*	[every year]#
Turbine and WHRU Duct Burner	NO _x	*	[every year]#

Initial test already performed

* Initial tests have been performed and the next method test using EPA approved test methods shall be performed within [one]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 [~~annually~~] 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 Depainting Operations

- A. VOC emissions from painting and depainting 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 NO_x 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 NO_x 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.

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ATTACHMENT B

Part H Comments and Responses

Big West Oil, LLC (BWO)

Comment Summary H-67: The commenter stated that increasing the stack testing frequencies of PM10 and PM2.5 in Subsections IX.H.2.a.i.B and IX.H.12.b.i.B to annual testing is a burden to not only the refinery but also to UDAQ. The additional workload will be in reviewing additional data and reports, such as stack testing protocols and stack testing results.

Pursuant to the Consent Decree requirements between BWO and the US Environmental Protection Agency, the most recent testing event occurred September 12, 2018. Prior to the Consent Decree, the approval order issued by UDAQ required FCC stack testing for PM once every five (5) years, in accordance with R307-165-2. These stack tests have established that controls for the stack are operating properly. In accordance with terms of the Consent Decree, BWO will be requesting that, under the Consent Decree, testing frequency on the FCC be changed to every three (3) years. To assure the control devices on the FCC stack are operating properly, BWO would also be measuring and recording opacity from the FCC as per the requirements of 40 CFR 63.1572(b) and complying with the opacity limitations as per the requirements of Table 7 to Subpart UUU of Part 63.

BWO is requesting that stack testing frequency remain at once every three (3) years for PM10 and PM2.5 for Subsections IX.H.2.a.i.B and IX.H.12.b.i.B.

UDAQ Response to H-67: UDAQ agrees with this comment. Where specific testing requirements are not identified by a federal standard, the UDAQ monitoring requirements for major sources of emissions are developed to provide an assurance of compliance. The monitoring standard must ensure appropriate pollutants are monitored, must accurately verify the source is operating below emission limits and specify a frequency that is adequate to show continual compliance. Measurements and sampling procedures must include specific test methods and protocols to provide representative and accurate emission data.

As BWO has referenced, Utah rule R307-165-2 requires emissions testing at least once every five (5) years for sources with approval orders or sources listed in section IX, Part H of the SIP. Three years ago the UDAQ established a minimum testing frequency of once every three (3) years for major sources.

NSR permitting engineers who develop the control plan have the responsibility to review emissions data and determine if the testing requirements meet the data goals. If the requirements for sampling demonstrate the data goals are being met, the monitoring requirements in the control plan will be retained. In most instances the minimum test frequency of once every three (3) years is adequate. With a requirement to perform annual stack testing, the Section IX, Part H listed sources would be subject to an estimated \$465,000 per year in added stack testing expenses. More frequent stack testing

will also result in increased workload for sources in regards to employee time spent planning, scheduling, and attending emission tests (several days to weeks dependant upon the emission unit being tested). UDAQ compliance staff will also see an increased workload due to review of the additional data and reports, such as stack testing protocols and stack testing results.

However, there are instances where more frequent monitoring is appropriate. Factors that are considered for requiring more frequent monitoring include variable emission streams, combustion of a variety or mixture of fuels, batch processes, or a history of operating close to permitted emission limits or even exceeding those limits. Specific sources required to conduct annual stack testing should be limited to Chemical Lime Company (Lhoist North America) (H.12.c), Compass Minerals (H.12.e.i and H.12.e.ii), Kennecott Utah Copper – Power Plant (H.12.j), and Nucor Steel Mills (H.12.k). All of the remaining major sources do not meet the criteria for more frequent monitoring listed above, and emissions’ testing once every three (3) years is appropriate to ensure compliance. Additionally, parametric monitoring requirements provide continuous additional data to demonstrate a source is operating within expected operating parameters. Examples of this are the refinery Fluid Catalytic Cracking Units. These parametric monitoring unit requirements are sufficient and are specifically listed under H.1.g.i.B.III, H.11.g.i.B.III and H.12.g.i.A.

The UDAQ believes that the stack testing frequencies developed by DAQ engineers and proposed for public comment on July 1, 2018 in the Utah State Implementation Plan Section IX, Part H are adequate for providing an assurance of compliance. Therefore, the applicable stack testing frequencies changed to annual testing and proposed in the November 1, 2018 Utah State Implementation Plan Section IX, Part H shall be corrected to once every (3) years. This will apply to the following Part H Sections:

H.1.g.i.B.II (page 4);	H.11.g.i.B.II (page 54);	H.12.g.i.B (page 75);
H.2.a.i.B (page 7);	H.12.a.iii.A.II.c (page 58);	H.12.h.i.C (page 80);
H.2.c.ii.A (page 13);	H.12.a.iii.B.II.c (page 58);	H.12.j.i.B.II (page 85);
H.2.d.i.B (page 14);	H.12.b.i.B (page 59);	H.12.j.ii.B (page 86);
H.2.d.v.B (page 18);	H.12.d.i.B (page 66);	H.12.m.i.B (page 92);
H.2.f.i.B (page 20);	H.12.d.ii.B (page 68);	H.12.n.i.B (page 97);
H.2.i.B.II (page 31);	H.12.d.v.B (page 70);	H.12.o.ii (page 98).
H.2.ii.B (page 32);	H.12.e.i (page 71);	
H.2.k.i.B (page 35);	H.12.e.iii.A (page 71);	
H.2.l.ii.E (page 40);	H.12.f.iv.B (page 74);	

Comment Summary H-68: The commenter provided information stating that subsections IX.H.2.a.vi.A and IX.H.12.b.vi.A were added at the company’s request. At the time, BWO agreed to a seasonally-adjusted lower baseline flow rate on refinery flare gas than that imposed by the refinery general requirements. In exchange, the refinery would be granted a two-year extension to implement the changes to reduce process flaring. BWO would be limited to 300,000 scfd of process gases, but this limit would not apply until January 1, 2021. BWO has since

1 **determined that the two-year extension is not necessary, and it will able to meet the**
2 **requirements of IX.H.1.g.v.B and IX.H.11.g.v.B in a timely manner. BWO therefore**
3 **requests that the requirements of IX.H.2.a.vi.A and IX.H.12.b.vi.A be dropped.**
4

5 UDAQ Response to H-68: UDAQ agrees with this comment. BWO had requested the
6 limitation during the original development of this SIP, as one of the BACT control
7 options for process flaring. UDAQ agreed that a seasonally-adjusted limitation on
8 process gases sent to the flare was a viable control option for BWO, given BWO's
9 specific process design constraints. After review, a limitation of 300,000 scfd from
10 October 1 to March 31, and 500,000 from April 1 to September 30 was found to be
11 BACT, with this limit being imposed on January 1, 2021. This was formalized as
12 conditions IX.H.2.a.vi.A and IX.H.12.b.vi.A in the PM10 and PM2.5 sections of the SIP.
13

14 During the first comment period, which was held between August 1 and August 31, 2018,
15 BWO provided verbal comment that this limitation was no longer necessary. BWO had
16 re-reviewed its process internally and determined that meeting the refinery general flare
17 requirements of IX.H.1.g.v.B and IX.H.11.g.v.B would be possible in a timely manner
18 (i.e. by January 1, 2019). With this new information, UDAQ agreed that the seasonally
19 adjusted limit and extension would not be required and stated it would remove the two
20 instances of the limitation. Unfortunately, a record of the verbal comment did not appear
21 in the official listing of comments received, nor did UDAQ's response to that
22 comment. Therefore, these two conditions were not removed from the final copy of
23 Section IX Part H that was presented to the Utah Air Quality Board (AQB) during the
24 September 2018 Utah AQB Meeting.
25

26 At that meeting, the AQB voted to drop all seasonal limitations in favor of imposing the
27 lower limit on an annual basis. In this particular case, that meant that BWO would be
28 shackled with a limitation of 300,000 scfd on an annual basis - a value that had never
29 been discussed or reviewed as BACT. When UDAQ reviewed BWO's proposal for a
30 seasonal limitation on flare gases, the proposal included two assumptions not present
31 during the September AQB decision. Seasonal limitations are imposed to control
32 emissions during periods when additional control is necessary because of atmospheric
33 conditions (chemistry, weather/climate) or because additional emissions are likely to
34 occur for reasons outside of that company's control (wildfires for example). When
35 seasonal limitations are imposed, the affected company can plan for the change - lowered
36 production, fuel switching, change in feedstocks, or the like. Simply changing a seasonal
37 limit to an annual limit does not take these types of changes into account. In BWO's case
38 in particular, the lower seasonal limitation was also being imposed after an extension of
39 two years - from January 1, 2019 to January 1, 2021. This was to allow BWO the
40 additional time to install equipment and processes necessary to cope with BWO's
41 potentially 200,000 scfd of process gas. Process gas which cannot be stored, sold,
42 vented, or recovered back into BWO's refining process. The September AQB decision
43 removed this extension period, and would require the lower limit be imposed
44 immediately - effectively forcing the refinery into non-compliance.
45

1 BACT in this case is to require BWO to meet the refinery general flare requirements of
2 IX.H.1.g.v.B and IX.H.11.g.v.B (the two requirements are identical):
3

4 *No later than January 1, 2019, all major source petroleum refineries in or*
5 *affecting any PM_{2.5} nonattainment area or a PM₁₀ nonattainment or maintenance*
6 *area shall either 1) install and operate a flare gas recovery system designed to*
7 *limit hydrocarbon flaring produced from each affected flare during normal*
8 *operations to levels below the values listed in 40 CFR 60.103a(c), or 2) limit*
9 *flaring during normal operations to 500,000 scfd for each affected flare. Flare*
10 *gas recovery is not required for dedicated SRU flare and header systems, or HF*
11 *flare and header systems.*
12

13 While this means that BWO is meeting only the baseline requirements established by
14 NSPS Subpart Ja, UDAQ has already discussed this in its BACT review for BWO (please
15 see the Technical Support Documentation - PM_{2.5} SIP Evaluation Report: Big West Oil,
16 LLC, July 1, 2018). BWO was specifically evaluated by EPA as a small refinery during
17 development of the NSPS and is cited as being “fuel gas long.” Meaning that as a result
18 of the specific refining processes in place at the BWO refinery, additional process gases
19 are generated that cannot be easily recovered and reused through typical flare gas
20 recovery. BWO must perform some amount of process flaring as no other means of
21 disposal of these gases exists.
22

23 Therefore, UDAQ recommends that the requirements of IX.H.2.a.vi.A and
24 IX.H.12.b.vi.A be removed entirely. The subsequent conditions of IX.H.2.a.vii and
25 IX.H.12.b.vii will be renumbered appropriately.
26
27

1 **Chevron Salt Lake Refinery**

2
3 **Comment Summary H-69: The commenter states that the flare flow requirements**
4 **should be consistent between the PM_{2.5} and PM₁₀ sections of the SIP.**
5

6 UDAQ Response to H-69: UDAQ agrees with this comment. This comment was
7 previously submitted as comment H-17 during the first comment period held between
8 August 1 and August 31, 2018. As stated in both versions of the comment, the language
9 present in the two sections of the SIP are nearly identical, but are inconsistent in
10 application. The commenter provided examples and proposed language that would
11 correct this inconsistency. Then and now, UDAQ agrees with the commenter that the
12 language should be applied appropriately. UDAQ clarified its position and included
13 revised language in its response to comments document. However, during revision of the
14 text of Section IX Part H prior to the September Air Quality Board Meeting, this
15 language was inadvertently left out of the final document. Therefore, UDAQ will update
16 the PM₁₀/PM_{2.5} language to read as follows:
17

18 ...petroleum refineries in or affecting any PM_{2.5} or any PM₁₀
19 nonattainment or maintenance area...
20

21 As stated in the previous response to comments, some requirements are still applicable to
22 all refineries regardless of source size (i.e. major source or minor source status) while
23 others are applicable to major sources only. It is not the intent of the language
24 clarification to change this applicability, only to establish that the requirements apply in
25 both PM₁₀ and PM_{2.5} areas.
26
27
28

29 **Comment Summary H-70: The commenter states that the application of certain**
30 **provisions of NSPS Ja to the [Chevron] Salt Lake Refinery is**
31 **inappropriate.** [clarification added]
32

33 UDAQ Response to H-70: UDAQ agrees with this comment. This comment was
34 previously submitted as comments H-14, H-15, H-18, H-20 and H-22 during the first
35 comment period held between August 1 and August 31, 2018. In essence, each of the
36 four established refineries operating catalytic cracking units inside the PM_{2.5}
37 nonattainment area commented that the requirement to install and operate a continuous
38 parameter monitoring system for determination of source-wide particulate matter
39 emissions. This requirement would be invalid on two levels. Those sources subject to
40 Subpart J rather than Subpart Ja already monitor different parameters than are required
41 under Subpart Ja - and for both subparts these monitoring requirements are applied to the
42 control device not to the calculation of emissions. For calculation of emissions,
43 Subsection IX.H.2.d.1.A (for Chevron, similar language can be found in the appropriate
44 location for each of the other refineries) provides for the use of stack tests to set emission
45 factors specifically for the catalytic cracking units.
46

1 Such determination was made by UDAQ in its previous response to comments document
2 (see UDAQ response to comment H-14 in that document). UDAQ proposed language
3 changes to requirements IX.H.1.g.i.B.III and IX.H.11.g.i.B.III. Unfortunately, during
4 preparation of the final SIP document prior to the September Air Quality Board Meeting,
5 these proposed language changes were inadvertently dropped. Therefore, UDAQ again
6 proposes that the following revised language be included in subsections IX.H.1.g.i.B.III
7 and IX.H.11.g.i.B.III:

8
9 *Subsection IX.H.1.g.i.B.III*

10
11 *No later than January 1, 2019, each owner or operator of an FCCU subject to*
12 *NSPS Ja shall install, operate and maintain a continuous parameter monitor*
13 *system (CPMS) to measure and record operating parameters from the FCCU and*
14 *control devices as per the requirements of 40 CFR 60.105a(b)(1). No later than*
15 *January 1, 2019, each owner or operator of an FCCU not subject to NSPS Ja*
16 *shall install, operate and maintain a continuous opacity monitoring system to*
17 *measure and record opacity from the FCCU as per the requirements of 40 CFR*
18 *63.1572(b) and comply with the opacity limitation as per the requirements of*
19 *Table 7 to Subpart UUU of Part 63.*

20
21
22 *Subsection IX.H.11.g.i.B.III*

23
24 *No later than January 1, 2019, each owner or operator of an FCCU subject to*
25 *NSPS Ja shall install, operate and maintain a continuous parameter monitor*
26 *system (CPMS) to measure and record operating parameters from the FCCU and*
27 *control devices as per the requirements of 40 CFR 60.105a(b)(1). No later than*
28 *January 1, 2019, each owner or operator of an FCCU not subject to NSPS Ja*
29 *shall install, operate and maintain a continuous opacity monitoring system to*
30 *measure and record opacity from the FCCU as per the requirements of 40 CFR*
31 *63.1572(b) and comply with the opacity limitation as per the requirements of*
32 *Table 7 to Subpart UUU of Part 63.*

33
34
35 The differences between the two subsections are specific to the type of particulate and
36 nonattainment area in question for each subsection. Holly Frontier, which operates WGS
37 systems on both FCCUs at its facility, has had specific language inserted into sections
38 IX.H.2.f.i.A and IX.H.12.g.i.A to address the inability to measure opacity at WGS
39 controlled Subpart J compliant FCCUs. That language is as follows:

40
41 *... As an alternative to a continuous parameter monitor system or continuous*
42 *opacity monitoring system for PM emissions from any FCCU controlled by a wet*
43 *gas scrubber, as required in Subsection IX.H.1.g.1.B.III (alt. IX.H.11.g.i.B.III),*
44 *the owner/operator may satisfy the opacity monitoring requirements from its FCC*
45 *Units with wet gas scrubbers through an alternate monitoring program as*
46 *approved by the EPA and acceptable to the Director.*

1
2 **Comment Summary H-71: The commenter states that the requirement to install a**
3 **flare gas recovery system at Flare No. 3 is incorrect.**
4

5 UDAQ Response to H-71: UDAQ agrees with this comment. The commenter is correct
6 that the installation of flare gas recovery systems were never intended to be installed for
7 specific types of exempted flare systems, as the flare gases from these systems could not
8 be recovered and reintroduced into the fuel gas system of the refinery. These exempted
9 flare systems included both SRU flares and header systems and HF flares and header
10 systems. In the case referenced by the commenter, Flare No. 3 is the flare directly tied to
11 the Chevron Salt Lake Refinery's HF Alkylation Unit - i.e. the HF flare for the
12 refinery. Therefore, UDAQ agrees with the commenter's proposal to correct Subsections
13 IX.H.2.d.vii and IX.H.12.d.vii to remove the reference to Flare No. 3.
14

1 **Northrop Grumman (ATK)**

2
3 **Comment Summary H-72: The commenter stated that in its review of Part H.12.a.iii**
4 **of the Plan regarding annual stack testing for natural gas boilers in buildings M-576**
5 **and M-14 there is no reason or analysis as to how an annual stack testing frequency**
6 **was derived in regards to emissions reduction/control. ATK states that they are not**
7 **aware of a cost benefit analysis that determines the cost of annual testing provides**
8 **more meaningful emissions control than the three year frequency. ATK is**
9 **requesting an additional evaluation of why annual stack testing on natural gas**
10 **boilers provides better emission control than a three year frequency.**
11

12 UDAQ Response to H-72: [See UDAQ Response to Comment H-67]
13

1 **PacifiCorp**

2
3 **Comment Summary H-73: The commenter disagrees with the decision to remove**
4 **the seasonally variable emission limit on PacifiCorp's Gadsby Power Plant Unit**
5 **#3. The seasonal limit should be reinstated allowing the unit to operate as needed**
6 **during peak load requirements.**
7

8 UDAQ Response to H-73: UDAQ agrees with this comment. At the September 2018
9 meeting of the Utah Air Quality Board (AQB), the AQB voted to remove seasonally
10 variable emission limits and instead impose the lower or more restrictive emission limit
11 on an annual basis. In the case of the Gadsby Power Plant, such a seasonal limitation
12 existed for Unit #3, a natural gas-fired boiler with a "summertime" limit of 203 lbs/hr
13 applicable between March 1 and October 31, and a "wintertime" limit of 142 lbs/hr
14 applicable between November 1 and the end of February (28th or 29th during leap
15 years). The decision of the AQB would make the 142 lbs/hr limit applicable on an
16 annual (year-round) basis. The commenter provided two main arguments for
17 reinstatement of the seasonal limitation:
18

- 19 1. The annual limitation would restrict the unit's summertime operating flexibility,
20 constraining the source's ability to meet customer load requirements - especially
21 during the summer months when peak loads are highest.
- 22 2. This decision appears to be in direct opposition to UDAQ's previous determinations
23 that seasonal limitations were BACT and were not arbitrary.
24

25 UDAQ agrees with both of these arguments. The first use of "wintertime" limitations
26 was during development of the PM10 SIP. Broadly, the period of highest ambient
27 particulate levels is found during wintertime inversions - so the restriction of particulate
28 and precursor emissions during these periods can be a useful work practice to reduce
29 overall ambient concentrations. This can be especially useful in those cases when the use
30 of add-on controls have been eliminated for technical or economic feasibility reasons.
31 Not restricting operations or emission rates during "summertime" periods allows the
32 source the flexibility to adjust for increased demand when needed - most often outside the
33 timeframe of highest particulate concentration.
34

35 UDAQ previously addressed a public comment received during the first comment period
36 (August 1 through August 31, 2018). In its response to Comment 33, UDAQ explained
37 that it was not arbitrary to allow seasonal limits in one instance, but not another, because
38 while Gadsby Unit 3 had seasonal controls, it also has limits that apply year-round, and
39 that those limits were considered BACT. UDAQ also explained that the BACT analysis
40 for Gadsby was based on actual emissions, and it was determined that the installation of
41 additional controls was not economically feasible. UDAQ also noted that Gadsby's
42 seasonal limits only apply to the lb/hr limit, and that Gadsby's concentration-based NOx
43 limits do not change on a seasonal basis.
44

1 As Gadsby Unit #3 has historically had NOx emissions that are within the summertime
2 limits, but would be in excess of wintertime limits, UDAQ submits that the appropriate
3 resolution is to reinstate the seasonal limitation on Gadsby Unit No. 3.
4

1 **Rio Tinto**

2
3 **Comment Summary H-74: UDAQ Correctly Proposed that KUC Stack Test the**
4 **Holman Boiler, Refinery Boilers, and In-Pit Crusher Every Three Years**

5
6 UDAQ Response to H-74: [See UDAQ Response to Comment H-67]
7

8 **Comment Summary H-75: UDAQ Correctly Determined that BACT for Unit 4 Does**
9 **Not Require a Fuel Switch to Natural Gas**

10
11 The commenter objects the decision of the Air Quality Board (AQB) during the October
12 3 meeting to prohibit KUC from combusting coal at any time at Unit 4. In response to
13 this decision, DAQ revised the November version of Part H to only authorize Unit 4 to
14 operate on natural gas and removed the seasonal provisions related to coal combustion at
15 Unit 4.
16

17 The commenter agrees with DAQ's Memo "Response to Board Motion on SIP", which
18 argued that fuel switching should not be considered BACT as part of this SIP. DAQ
19 stated that since Unit 4 has the seasonal prohibition on coal burning during the inversion
20 season, prohibiting coal burning during the summertime will have no impact in
21 controlling the emissions that contribute to the wintertime inversion season. Therefore,
22 fuel switching is not an appropriate BACT measure for this SIP.
23

24 Given the facts stated in DAQ's Memo "*coupled with the limitations imposed by Utah*
25 *Code section 19-2-109, there is no foundation for the AQB to make a determination that*
26 *the imposition of controls on Unit 4's coal operations are necessary for the PM2.5 SIP.*"
27

28 The commenter also states that BACT does not preclude UDAQ/AQB from applying
29 seasonal controls on Unit 4. The commenter states that "EPA has repeatedly embraced
30 the idea that a SIP may address a pollutant that manifests itself with greater seasonal
31 concentrations with controls and limitations that apply during a season". The commenter
32 specifically points out to EPA's guidance referring to seasonal emissions considerations
33 for ozone SIPs.
34

35 The commenter also points out a response to a 1998 comment on the NOx SIP call where
36 EPA rejected the notion that EPA could use ozone SIP to address non-ozone problems.
37 The commenter stated that "*UDAQ's memo raises the specter that the focus on Unit 4's*
38 *coal operations may be motivated by a goal of attacking non-PM2.5 issues, such as*
39 *controlling emissions impacting ozone concentrations in the summertime. As EPA*
40 *explained in the NOx SIP call, it is not appropriate to use a SIP that is designed to bring*
41 *an area into compliance with a particular NAAQS to attack an unrelated problem.*"
42

43 The commenter requests that "*UDAQ revise Part H to (1) allow for both natural gas and*
44 *coal combustion at Unit 4, and (2) re-insert the seasonal prohibition on coal combustion*
45 *between November and the end of February.*"
46

1 **UDAQ Response to H-75:**

2
3 As stated in DAQ's Memo "Response to Board Motion on SIP" and in Comment 1 of the
4 "Comments on Notice of Proposed Rule, Section IX, Emission Limits and Operating
5 Practices, Part H" submitted by UDAQ, the UDAQ does not agree with the AQB motion
6 that fuel switching should be considered BACT for Unit #4.
7

8 UDAQ agrees that controls for the PM2.5 SIP should have the primary purpose of
9 controlling emissions that contribute to the wintertime air shed. UDAQ also stated that
10 fuel switching may be a more appropriate BACT determination under different
11 circumstances, such as for the ozone SIP or as a BACT analysis for a permitting action.
12

13 As such, UDAQ will reinstate the Part H provisions allowing coal to be combusted
14 during summertime.
15

16 **Comment Summary H-76: UDAQ Applied Overly Aggressive Control Efficiencies**
17 **to Arrive at an Unrealistic Emission Limitation For Unit 4's Natural Gas**
18 **Operations**
19

20 UDAQ proposed a NOx limit of 20 ppmvd (17 lbs/hr) for Unit 4 when combusting
21 natural gas. This limit accounts for the BACT controls of over-fired air (OFA), low NOx
22 burners (ULNB), and Selective Catalytic Reduction (SCR), as detailed in the TSD
23 document dated July 1, 2018. This limit was based on a 50% reduction from OFA and
24 ULNB and 90% from SCR.
25

26 The commenter "*objects to the 20 ppmv (17 lbs/hr) emission limitation because UDAQ*
27 *derived the emission limitation from overly-aggressive control efficiencies resulting from*
28 *the installation of SCR and OFA.*" The commenter stated that "*emission limitations that*
29 *are unrealistic, based on overly-aggressive control efficiencies, or derived from best-case*
30 *scenario operations do not represent BACT and cannot be implemented.*"
31

32 KUC commissioned a site-specific study to evaluate potential controls at Unit 4. Results
33 of this study were originally submitted in May 2018 and were again included with the
34 public comments received on November 30, 2018. The study identified OFA and SCR as
35 potential control options and suggested a range of control efficiencies for these
36 technologies. Based on the information from this study, KUC proposed control
37 efficiencies of 75% for SCR and 30% for OFA, and a resulting NOx limitation of 60
38 ppmvd.
39

40 The commenter stated that "*there are significant questions as to the likelihood that SCR*
41 *and OFA will, in fact, meet either of these control efficiencies, and, in turn, that KUC can*
42 *consistently meet the 20 ppmv emission limitation at Unit 4.*"
43

44 **UDAQ Response to H-76:**
45

KUC believes that DAQ used overly-aggressive control efficiencies for natural gas operations and has proposed different control efficiencies for OFA and SCR for natural gas operations. Below is a comparison of the control efficiencies used by DAQ versus the control efficiencies proposed by KUC. The control efficiencies proposed by KUC are based on vendor estimates provided in the May 2018 study, which assumed same control efficiencies for both natural gas and coal. KUC is only requesting a change to the natural gas control efficiencies. The control efficiencies from DAQ were proposed in the BACT analysis in the TSD document dated July 1, 2018.

Table H-76.1 – Control Efficiencies and BACT Limits Comparison

Control	Proposed Control Efficiencies	
	DAQ	KUC
OFA	50%	30%
ULNB / LNB		Not evaluated
SCR	90%	75%
NOx Limits		
Current NOx Limit	336 ppmvd (306 lb/hr)	
Proposed NOx Limit	20 ppmvd / 17 lb/hr / 0.02 lb/MMBtu	60 ppmvd / 54 lb/hr / 0.06 lb/MMBtu

Stack Test Results

DAQ reviewed NOx concentrations and emission rates from stack tests conducted between 2010 and 2017. Results from these stack tests for NOx emissions from Unit 4 are summarized below. As shown in Table H-76.2, NOx concentrations from natural gas combustion have been measured at 25% to 46% of the current Approval Order (AO) (DAQE-AN105720031-15) limit of 336 ppm. The table below also shows resulting emission limits if control efficiencies are applied to stack test results. Both KUC's and DAQ's proposed controlled efficiencies were applied. For a conservative estimate, control efficiencies were only applied to the maximum stack test result.

Table H-76.2 – Post-Control Emission Based on Stack Test Data

Control	Natural Gas
Emission Limit <i>ppm (lb/hr)</i>	336 (306)
Stack Test Results (2010 – 2017)	
Max NOx <i>ppm (lb/hr)</i>	154 (165)
% Emission Limit	46% (54%)
Min NOx <i>ppm (lb/hr)</i>	82.3 (67.3)
% Emission Limit	25% (22%)
Resulting Post-Control Emission Limits	
<i>Based on DAQ Control Efficiencies</i>	
Emission Limits	7.7 ppm / 8.2 lb/hr /

	0.01 lb/MMBtu
<i>Based on KUC Control Efficiencies</i>	
Emission Limits	27 ppm / 29 lb/hr / 0.03 lb/MMBtu

By applying DAQ's proposed control efficiencies to actual emission data, NO_x concentrations and emission rates are much lower than the proposed limits. By applying KUC's proposed control efficiencies to actual emission data, NO_x concentrations are estimated at 27 ppmvd, slightly higher than the proposed limit of 20 ppmvd. The emission rates are estimated at 29 lb/hr and 0.03 lb/MMBtu, higher than their respective proposed emission limits of 17 lb/hr and 0.02 lb/MMBtu.

Although stack test data indicates that NO_x from natural gas combustion is significantly lower than the current AO limit, there is also significant variability in the emission rates. For instance, the maximum concentration is almost double the minimum concentration (154 ppm vs 82.3 ppm). DAQ acknowledges that with this variation in emission rates, a compliance buffer may be appropriate to account for operational fluctuations.

Low NO_x Burners

As shown in Table H-76.1, ultra-low NO_x and low NO_x burners were not evaluated as part of the May 2018 study. As stated in the comment, Unit 4 currently utilizes a low NO_x burner. KUC stated that since the unit is already equipped with a low NO_x burner, further evaluation of this technology was not conducted on the assumption that additional emission reductions would not be achieved. However, DAQ does not have records of when the low NO_x burners were installed and the NO_x rating for such burners. Based on DAQ's records, the NO_x limit of 336 ppm (306 lb/hr) for natural gas operations has remained unchanged since at least the 1994 SIP. The NO_x limit for coal operations in the 1994 SIP was listed as 597 ppmvd, higher than the current uncontrolled NO_x limit of 384 ppm in subsequent SIPs. Since the only NO_x limit that has changed is related to coal, it is possible that the low NO_x burner referred to in the comment was installed for coal operations, not natural gas. Due to the lack of information on this issue, DAQ speculates that there are three possibilities: 1) The low NO_x burner was only installed for coal; 2) Unit 4 is equipped with a low NO_x burner which was most likely installed before 1994; 3) A low NO_x burner was installed but the NO_x rating of this burner is unknown and permitted emission limits were not updated to account for the low NO_x burner.

None of the above-mentioned possibilities precludes ultra-low NO_x and/or low NO_x burners for natural gas combustion from being evaluated as part of BACT. DAQ believes that ultra-low NO_x burners and/or low NO_x burners should have been evaluated as part of the study and the BACT analysis for this unit. Even if a low NO_x burner has been installed at Unit 4, currently available burner technology should be evaluated as those will have higher control efficiencies.

Furthermore, the BACT emission limit for this SIP is being estimated based on the uncontrolled baseline emission rate of 336 ppm, as shown in Table H-76.1. If a low NO_x

1 burner was installed at Unit 4, then the starting baseline emission rates should be lower
2 than 336 ppm, which would result in different control efficiencies than proposed.

3
4 As previously stated, DAQ proposed a 50% control efficiency for both OFA and low
5 NOx burners in the TSD BACT analysis. DAQ is not disagreeing with the control
6 efficiency of 30% for OFA alone, as proposed by KUC. However, DAQ cannot reduce
7 the proposed control efficiency for pre-SCR controls to 30% when one of the control
8 technologies identified in the TSD BACT analysis was not evaluated as part of the May
9 2018 study nor accounted for in the proposed control efficiency for this comment.

10 11 SCR System Design

12 The SCR will control emissions after OFA and low NOx burner. DAQ understands that
13 the design for a SCR system would be based on the following:

- 14 • The SCR would be sized based on emission profile and operating parameters
15 (flow rates, temperatures, etc) from coal combustion.
- 16 • More ammonia would be required to control emissions from coal than natural
17 gas.
- 18 • The SCR would likely be designed with two injection skids, one to provide
19 higher ammonia injection rates during coal combustion and another to provide
20 lower ammonia injection rate during natural gas combustion.
- 21 • The SCR system would be equipped with inlet and outlet NOx monitors to adjust
22 the ammonia quantity needed in the flue gas stream to achieve the required NOx
23 reduction. This type of monitoring would allow the system to quickly adjust for
24 different loads and concentrations.

25
26 DAQ consulted with engineering firms that typically design and install SCRs and
27 confirmed that 90% control efficiency for SCR is a typical requirement and design
28 parameter. The target removal efficiency for a system can be maintained with proper
29 monitoring and design. According to EPA and vendor literature, SCR control efficiencies
30 usually range from 70% to 95%. Some of the factors that affect SCR control efficiency
31 include boiler type, age of catalyst, acceptable ammonia slip, fuel type, and flue gas
32 temperature. Vendor estimates from the May 2018 study were based on 80% control
33 efficiency and KUC has proposed 75% control efficiency. DAQ proposes to use the
34 vendor estimate of 80% control, which is based on site-specific knowledge of the unit as
35 well as engineering judgement from design experience.

36 37 Conclusion

38 DAQ does not agree with reducing the pre-SCR control efficiency to 30% because low
39 NOx burners were not evaluated. DAQ proposes to use the vendor-provided estimate of
40 80% for the SCR control efficiency. This control efficiency is within the typical SCR
41 control efficiencies for natural gas combustion but also adds a compliance buffer to
42 account for variability in measured emission rates, age of the boiler, and any other
43 uncertainties. By applying these control efficiencies to the 336 ppm NOx limit, the new
44 emission limit is estimated at 33 ppm. This value is comparable to the post-control
45 emissions of 27 ppm estimated based on actual stack test data and KUC's proposed
46 control efficiencies, as shown in Table H-76.

Therefore, DAQ proposes to update the NO_x limit to 30 ppmvd. Corrections were made to the estimates for emission rates in lb/hr and lb/MMBtu. The equivalent limit proposed is: 30 ppmvd/ 32 lb/hr / 0.04 lb/MMBtu.

In summary, DAQ proposes to revise the NO_x BACT limits in Section IX.H.12.j.i.A.II.2 to 30 ppmvd/ 32 lb/hr / 0.04 lb/MMBtu, based on the following.

- KUC neglected to evaluate a common control option (low NO_x burners) which would further reduce NO_x emissions. Low NO_x burners, combined with OFA and SCR are common controls for natural gas and coal-fired units listed in EPA RBLC database. Low NO_x burners were also included as part of the TSD BACT determination for this Unit. Therefore, DAQ maintained the 50% control efficiency determined to be BACT for OFA and low NO_x burners.
- Given actual emission rates from stack tests, the limit proposed by DAQ is achievable. However, the limit was raised based on a less stringent SCR control efficiency to account for variability in measured emission rates, age of the boiler, and any other uncertainties.
- NO_x emissions from coal are much higher than from natural gas, yet KUC is proposing an emission limit that is very close (60 ppm for natural gas and 80 ppm for coal). SCR system can be adjusted to optimize ammonia injection rates for coal and natural gas, so removal efficiency can be maximized. As such, DAQ sees no reason to have such a narrow range of limits for natural gas and coal.

Comment Summary H-77: The VMT Limit for the Bingham Canyon Mine Should Apply Only to Diesel-Fired Haul Trucks

DAQ has included a daily mileage cap in PM₁₀ SIP (Condition H.2.g.i.A) and in the proposed PM_{2.5} Serious SIP (Condition H.12.h.i.A). These conditions limit the maximum daily mileage for ore and waste haul trucks to 30,000 miles.

The commenter has requested that this limit apply to diesel-powered haul trucks only. This revision “would acknowledge the purpose of the limitation and provide KUC with the flexibility to explore the viability of alternatively-powered haul trucks at the BCM.”

Specifically, “KUC is interested in the possibility of bringing alternatively-powered haul trucks to the fleet of vehicles that operate at the BCM if these vehicles become available. However, KUC is concerned that the SIP as it is currently proposed could create an impediment to testing and deploying alternatively-powered haul trucks at the BCM. For example, alternatively-powered haul trucks may not be as large as KUC's largest haul trucks. If that were the case, the limitation on vehicles miles traveled - if applied beyond the diesel fired fleet - could create a disincentive to deploying alternatively-powered haul trucks at the BCM.”

The commenter has requested this revision for both Condition H.2.g.2i.A in the PM₁₀ SIP and Condition H.12.h.i.A in the PM_{2.5} SIP.

1
2
3 **UDAO Response to H-77:**

4 The DAQ agrees with making this change in an effort to encourage KUC to use
5 alternatively-powered haul trucks at the BCM.
6

7 One potential concern is that the increased traffic from alternatively-powered haul trucks
8 could increase fugitive emissions from the BCM. However, DAQ believes that the KUC
9 BCM AO (DAQE-AN105710042-18) has other limitations that appropriately limit
10 fugitive emissions. For instance:

- 11 • Condition II.B.1.e: *Total material moved (ore and waste) shall not exceed*
12 *260,000,000 tons per rolling 12-month period.*
13

14 This limit will indirectly control fugitive emissions by limiting the amount of
15 material that can be removed from the mine.
16

- 17 • Condition II.B.1.f: *The following site-wide emission limits at the BCM shall not*
18 *be exceeded:*

19 A. *7,350 tons of NOx, PM10 and SO2 combined per rolling 12-month*
20 *period.*

21 B. *6,205 tons of NOx, PM2.5 and SO2 combined per rolling 12-month*
22 *period.*
23

24 This limit applies to facility-wide operations, which includes fugitive emissions.
25 Fugitive emissions for haul roads are estimated based on the number of miles
26 travelled inside the pit and outside the pit from all haul traffic. This would include
27 any new alternatively-powered haul trucks.
28

29 DAQ will make the following changes to Part H:
30

31 Condition H.2.g.i.A. Maximum total mileage per calendar day for diesel-powered ore and
32 waste haul trucks shall not exceed 30,000 miles.
33

34 Condition H.12.h.i.A. Maximum total mileage per calendar day for diesel-powered ore
35 and waste haul trucks shall not exceed 30,000 miles.
36

37 **Comment Summary H-78: The "Implementation Schedule" for Haul Trucks in Part**
38 **H.2 Should Be Removed**
39

40 Condition H.2.g.i.D of the PM10 SIP states that “KUC shall purchase new haul trucks
41 with the highest engine Tier level available which meet mining needs. KUC shall
42 maintain records of haul trucks purchased and retired.”
43

44 This condition was originally proposed in the July version of Part H.12, but was removed
45 from Part H.12 as documented in Response to H-38 of the *October 3, 2018 Memo to the*
46 *AQB proposing for public comment amended Part H.*

1
2 The commenter stated that “*UDAQ retained the provision in Part H.2. KUC understands*
3 *that UDAQ believes that Condition H.2.g.i.D remains viable and outside of Title II's*
4 *preemption because it is tied to the 30,000 vehicle miles traveled, which is not an*
5 *emission standard.*”

6
7 Specifically, the commenter mentioned a US Supreme Court definition applied to
8 “*California regulation that dictated the composition of vehicles purchased by public and*
9 *private fleet operators and found that such fleet restrictions were in preempted by Title*
10 *II.*
11 *A command, accompanied by sanctions, that certain purchasers may buy only vehicles*
12 *with particular emission characteristics is as much an 'attempt to enforce' a 'standard' as*
13 *a command, accompanied by sanctions, that a certain percentage of manufacturer's sales*
14 *volume must consist of such vehicles.*”

15
16 The commenter stated that this condition is in conflict with Title II as it “*instructs KUC*
17 *that it may only buy certain haul trucks which meet particular emission characteristics*”

18
19 The commenter also stated that the intent of this condition is unclear since federal
20 regulations already dictate “*what haul trucks KUC may purchase and deploy at the*
21 *BCM*”

22
23 **UDAQ Response to H-78:**

24
25 Agreed. UDAQ will remove Condition H.2.g.i.D from the PM10 SIP.
26

1 **Tesoro Refining & Marketing Company**

2
3 **Comment Summary H-79: The commenter stated that Stack Test Frequencies for**
4 **FCCUs is sufficient to ensure the units are operating as designed. Tesoro stated**
5 **additional risks associated with the testing location (elevated 200') and weather**
6 **related. Tesoro also stated that the continuous compliance demonstration using**
7 **CPMS ensures operation of the equipment as designed as shown through the last**
8 **two stack testing events where emissions were less than 50% of the established**
9 **limit.**

10
11 UDAQ Response to H-79: [See UDAQ Response to Comment H-67]

12
13 **Comment Summary H-80: The commenter suggested edits to two refinery general**
14 **requirements - IX.H.1.g.i.B.III and IX.H.11.g.i.B.III. This comment is similar to**
15 **comment H-70 list above, and is identical to comment H-22 of the original comment**
16 **period (August 1 through August 31, 2018).**

17
18 UDAQ Response to. H-80: UDAQ agrees with this comment. Please see UDAQ's
19 response to comment H-70 for a complete analysis and UDAQ's proposed resolution.

20
21 **Comment Summary H-81: The commenter supplied additional information to**
22 **support the claim that SCR should not be considered as BACT for application on**
23 **the Tesoro Refinery cogeneration turbine units.**

24
25 UDAQ Response to H-81: UDAQ agrees with this comment. The commenter correctly
26 points out that it would be extraordinarily difficult to design, engineer, construct and
27 install a SCR system for the cogeneration units by the regulatory attainment date of
28 December 31, 2019. No credit can be taken for any BACM or more specifically BACT
29 which is installed after the attainment date. This is clarified in the rule under the
30 requirements for attainment demonstration for nonattainment areas reclassified as Serious
31 – see 40 CFR 41.1011(b)(5):

32
33 *Required timeframe for obtaining emissions reductions. For each*
34 *Serious nonattainment area, the attainment plan must provide for*
35 *implementation of all control measures needed for attainment as*
36 *expeditiously as practicable. All control measures must be*
37 *implemented no later than the beginning of the year containing the*
38 *applicable attainment date, notwithstanding BACM*
39 *implementation deadline requirements in § 51.1010.*
40

41 Thus, for any BACM/BACT to be included for emission reductions, it must be
42 implemented no later than the beginning of the year containing the regulatory attainment
43 date, i.e. on or before January 1, 2019. In order for a control system to be in operation by
44 January 1, 2019, it must be constructed no later than December 31, 2018. As this
45 response to comments document is being prepared for final action by the Utah Air
46 Quality Board at the January 2019 meeting, it is impossible for such construction to even

1 be authorized, let alone completed by this deadline. SCR does not constitute BACT in
2 this case. This was also addressed in UDAQ's response to comment H-24 in the first
3 response to comments document covering the original comment period (August 1 to
4 August 31, 2018). Specifically, see the section addressing Most Stringent Measures
5 (MSM) in that comment response. No changes are necessary to either the language of
6 Part H or the technical support documentation, as this comment response should be used
7 in conjunction with that document.
8
9

1 **University of Utah**

2
3 **Comment Summary H-82:** The commenter stated that the impact from proposing
4 an increase in stack testing from every three years to annual would burden
5 operations without any commensurate benefits such as increased efficiency or
6 reduced emissions. Commenter also stated that stack testing preparation and
7 execution requires a significant time commitment from environmental staff, and has
8 the potential to distract from other environmental efforts across the campus. The
9 University of Utah also concurred with UDAQ that annual stack testing would
10 result in an estimated \$30,000 per year in added stack testing expenses.
11

12 UDAQ Response to H-82: [See UDAQ Response to Comment H-67]

13 **Utah Manufacturers Association**

14
15 **Comment Summary H-83:** The commenter was focused on the issue of stack testing
16 frequency required by Part H of the Serious Area PM_{2.5} SIP for the Salt Lake City
17 Nonattainment Area. Commenter stated that the purpose of stack testing is to
18 assure compliance with emission limitations but went on to state that stack tests are
19 resource intensive and costly to conduct. Substantial up-front planning to develop
20 and approve the test protocol, obtain bids from stack test vendors, select the stack
21 test firm and to coordinate test dates with production runs all require consideration
22 when determining a stack testing frequency.
23

24 **Commenter stated that a member company is currently required to test three**
25 **sources for NO_x, CO, and PM_{2.5} once every three years. The stack testing costs**
26 **\$35,000 to perform over a four-day period. This testing also requires two week's**
27 **worth of time by the company, including a week of preparation and another week**
28 **for coordination during the week of the stack test. Commenter concluded that**
29 **increasing the frequency to require an annual stack test, the company's cost, time**
30 **and resources would increase by 200% (i.e., \$70,000 in costs and 4 weeks of staff**
31 **effort over the current base).**
32

33 UDAQ Response to H-83: [See UDAQ Response to Comment H-67]
34

1 **Utah Petroleum Association**

2
3 **Comment Summary H-84:** [submitted by the Utah Petroleum Association
4 (UPA)]: **Scope of Comment:** In view of the procedural history of the Part H
5 rulemaking, UPA understands that the entirety of the revisions being proposed to
6 Part H as part of the PM_{2.5} SIP BACT rulemaking – including those initially noticed
7 for public comment in the July 1, 2018 Utah State Bulletin – are properly subject to
8 comment during the current comment period. UPA furthermore requests that
9 UDAQ respond to comments made by UPA on the original Part H rulemaking that
10 it appears were inadvertently overlooked; specifically, Enclosure 2 to UPA’s August
11 15, 2018 comments (Revisions to Section IX, Control Measures for Area and Point
12 Sources, Part H. Emission Limits, Specific Comments on Parts H.1, H.2, H.11, &
13 H.12).

14
15 UDAQ Response to H-84: UDAQ regrets any confusion about the scope of comments
16 that could be made regarding Part H. The intent was to solicit only those comments
17 addressing new issues proposed for comment at the October UAQB, and potentially
18 avoid a high volume of comments that had already been made. UDAQ did receive a
19 small few comments addressing issues that opened for review in July, and these
20 comments have been addressed herein.

21
22 UDAQ is also responding to comments made by UPA in Enclosure 2 to its August 15,
23 2018 comments. These comments were in fact overlooked during the previous comment
24 period, but are now addressed in H-86 through H-91.

25
26 **Comment Summary H-85:** [submitted by the Utah Petroleum Association
27 (UPA)]: **Provisional adoption of Part H:** In previous comments UPA noted the
28 importance of the Board determining that the Part H controls are necessary for
29 achieving attainment of the PM_{2.5} NAAQS. Those comments also included a report
30 discussing the results of major stationary source precursor demonstrations
31 performed for all four PM_{2.5} precursors. These demonstrations show that
32 controlling any of these precursors from “major” sources would have an
33 insignificant effect of PM_{2.5} levels, and that therefore, *additional* precursor controls
34 on major stationary sources are not necessary.

35
36 UDAQ has indicated its intention to complete its own analysis, and UPA appreciates
37 the efforts in this regard. UPA understands that this is a significant undertaking,
38 and that it will likely be several months before UDAQ can reach a definitive
39 conclusion. Also noted is that UDAQ’s precursor demonstration should be subject
40 to public review and comment.

41
42 However, UDAQ has also expressed the need to continue with the rulemaking
43 process required to implement BACT in the event that such additional controls are
44 ultimately deemed necessary. UPA acknowledges the need for all necessary
45 rulemaking to be completed timely.

1 **UPA believes that these efforts – UDAQ’s completion of its precursor demonstration**
2 **and continued development of potential BACT – can and should proceed on parallel**
3 **tracks.**

4
5 **UPA believes it would be most appropriate for UDAQ to have entirely completed its**
6 **precursor demonstration – including notice and public comment – prior to making**
7 **any decision on the Part H rulemaking. However, to the extent that UDAQ**
8 **determines, for administrative or other reasons, to proceed with a final rulemaking**
9 **on the proposed Part H rulemaking, we urge the Agency to do so provisionally,**
10 **making a revised Part H effective contingent upon the outcome of a final decision on**
11 **the precursor demonstration.**

12
13 **In doing so it could follow an approach similar to that taken when the Board**
14 **provisionally adopted an alternative offset requirement as part of the PM₁₀ SIP**
15 **rulemaking. UDAQ would thereby accommodate the Utah Air Conservation Act,**
16 **the Utah Administrative Rulemaking Act, and the Clean Air Act and federal SIP**
17 **rulemaking requirements.**

18
19 UDAQ Response to H-85: As stated in the responses to Comment A-16 (*UPA comments*
20 *urging inclusion of major stationary source precursor demonstrations*), UDAQ is
21 electing not to include a major stationary source precursor demonstration for any of the
22 PM_{2.5} precursors at this time.

23 Had UDAQ instead elected to do so, the commenter makes a valid point in that EPA
24 would still have had to approve the demonstration in order that BACT controls for such
25 pollutant(s) would thereby not be required, and this takes time. Meanwhile, by state law,
26 a source may have been faced with a deadline for purchase and installation of control
27 equipment which ultimately may not have been required. Had this been the case, a
28 provisional construction of Part H could have been a suitable path. Since, however, a
29 major stationary source precursor demonstration will not be part of the SIP. It will not be
30 necessary to wait for EPA to render its decision on any such precursor demonstration.
31 Part H may be acted upon by the UAQB without delay.

32
33 **Comment Summary H-86: The commenter suggests that the use of all EPA-**
34 **approved test methods should be allowable, and that the words “acceptable to the**
35 **Director” should be stricken from the general requirements of IX.H.1.e and**
36 **IX.H.11.e.**

37
38 UDAQ Response to H-86: UDAQ disagrees with this comment. UDAQ has previously
39 responded to this concept during its response to comment H-20 of the first set of
40 comments received during the original comment period held August 1 through August
41 31, 2018. In that response, UDAQ expressed that it was not the intent of the phrase
42 “acceptable to the Director” to imply that the Director would not find an EPA-approved
43 testing method acceptable generally. Rather, when the source wishes to use a testing
44 method to demonstrate compliance with a particular emission limit found in IX.H.2,
45 IX.H.3, IX.H.12 or IX.H.13, the choice of testing method must be acceptable to the
46 Director as well as being an EPA-approved testing method. The acceptance of the

1 Director is to prevent the source from choosing an inappropriate (although EPA-
2 approved) testing method - such as using an SO₂ test to demonstrate compliance with a
3 NO_x emission limitation. Obviously such a test would be incorrectly applied, but the
4 removal of the acceptability phase as suggested by the commenter would allow for such a
5 possibility to occur. The language “acceptable to the Director” will not be
6 removed. Sources already have the ability to suggest and use alternative EPA-approved
7 tests at any time; this language simply requires that the source receive approval prior to
8 performing the test.

9
10 **Comment Summary H-87: The commenter suggests that the use of AP-42 emission**
11 **factors should not be prescribed, and that the words “or other EPA-approved**
12 **methods” should be added to allow for flexibility.**

13
14 UDAQ Response to H-87: UDAQ agrees with this comment. During development of the
15 stack testing requirements for FCC units at the refineries, the ability to update or change
16 emission factors through stack testing was inadvertently removed from several sections
17 of IX.H.2 and IX.H.12 (specifically: IX.H.2.a.i.B, IX.H.2.a.ii.B, IX.H.2.d.i.B,
18 IX.H.2.d.ii.B, IX.H.2.k.i.B, IX.H.2.k.ii.B, IX.H.12.a.i.B, IX.H.12.a.ii.B, IX.H.12.d.i.B,
19 IX.H.12.d.ii.B, IX.H.12.k.i.B, and IX.H.12.k.ii.B). Including the commenter’s suggested
20 language allows these sources to update emissions factors as originally intended. Some
21 other minor language changes will be made where appropriate and necessary to allow for
22 proper grammar and natural english phrasing. In addition, a change will be made in the
23 sections listed in the parenthetical section above to again allow for updating of emission
24 factors through stack testing as originally intended.

25
26 **Comment Summary H-88: The commenter believes that the general testing**
27 **requirements for PM₁₀ and PM_{2.5} should be consistent.**

28
29 UDAQ Response to H-88: UDAQ agrees with this comment. It was the intention of
30 UDAQ to update the PM₁₀ section of the general requirements (section IX.H.1) and the
31 PM_{2.5} section of the general requirements (section IX.H.11) to be as identical as
32 possible. Subsection IX.H.11.e.i.B provides for the use of either EPA Test Method 2 or
33 Method 19. However, Subsection IX.H.1.e.i.B provides for the use of only EPA Method
34 2. Therefore, Subsection IX.H.1.e.i.B (PM₁₀) should be modified to include Method 19
35 as an acceptable method in order to be consistent with Subsection IX.H.11.e.i.B
36 (PM_{2.5}). Similarly, Subsections IX.H.1.e.i.C IX.H.11.e.i.C should be modified to
37 provide for the use of EPA Methods 5B, 5F and 17, since the use of these methods is
38 necessary to monitor the emissions from sulfur recovery plants.

39
40 **Comment Summary H-89: The commenter disagrees with the use of the terms**
41 **“particulate matter” and “PM” as these terms are undefined, and wants UDAQ to**
42 **use only the defined terms PM₁₀ and PM_{2.5} in the SIP and supporting documents.**
43

44 UDAQ Response to H-89: UDAQ disagrees that the terms “particulate matter” and “PM”
45 are ambiguous given their use in the context of the Utah SIP and specifically within the
46 PM₁₀ and PM_{2.5} sections of the Utah SIP. PM in particular is of use in conjunction with

1 stack testing requirements, as Method 5 series tests and Method 17 are both general
2 particulate matter tests and do not fractionate the collected material into the more specific
3 PM10 or PM2.5. Indeed, the commenter requested the addition of additional particulate
4 matter testing in its previous comment (see Comment H-88). There is only one
5 occurrence of the term “particulate matter” in the language of Section IX, Part H, which
6 is clarified by an immediate subsequent parenthetical of (PM2.5). No changes to the
7 language of Part H are required.
8

9 **Comment Summary H-90: Applying Federal Clean Air Act NSPS Ja Requirements**
10 **to Facilities Subject to NSPS J is Inappropriate.**
11

12 UDAQ Response to H-90: This comment is essentially identical to comment H-70
13 included above. UDAQ agrees with this comment. For details on UDAQ’s analysis and
14 UDAQ’s proposed resolution, please see the response to comment H-70.
15

16 However, the commenter did bring up one additional point not previously covered in
17 comment H-70, or any of the comments provided during the original comment period of
18 August 1 through August 31, 2018. As part of the corrections to address the
19 misapplication of Subpart Ja, Subsections IX.H.1.g.i.A.II and IX.H.11.g.i.A.II also need
20 to be updated to remove the phrase “by following 40 C.F.R. §60.105a(g).” and replacing
21 it with the phrase “using a CEM in accordance with IX.H.1.f.” (in the case of Subsection
22 IX.H.1.g.i.A.II) or “using a CEM in accordance with IX.H.11.f.” (in the case of
23 Subsection IX.H.11.g.i.A.II).
24

25 **Comment Summary H-91: Petroleum Refineries FCCU Particulate Matter**
26 **Emission Limit Should Not Be Based on 3-hour Average Basis.**
27

28 UDAQ Response to H-91: UDAQ agrees with this comment. The commenter is correct
29 in pointing out that the emission limit in Subsections IX.H.1.g.i.B.I and IX.H.11.g.i.B.I is
30 1.0 lbs per 1000 lbs of coke burned. The SIP expressly requires that compliance with this
31 emission limit be determined in accordance with the stack test protocol provided in NSPS
32 J or NSPS Ja. The stack test protocol under NSPS J requires that the “sampling time for
33 each run shall be at least 60 minutes.” Separately, NSPS Ja requires that particulate
34 matter performance tests “consist of 3 valid test runs” and that “the duration of each test
35 run must be no less than 60 minutes.” Thus, the stack tests protocols under NSPS J and
36 NSPS Ja set forth specific parameters for both the number and length of each test that
37 must be satisfied in order to conduct a valid test.
38

39 The commenter suggested replacing the phrase “burned on a 3-hour average basis” with
40 the phrase “burn-off”. UDAQ agrees with this replacement.
41

1 **Matt Miller**

2
3 **Comment Summary H-92: Commenter was in favor of moving the monitoring from**
4 **every 3 years to annually, and reduction in routine flaring. Also approved of switch**
5 **to year-round natural gas (assumed at Kennecott as no source reference was made)**
6 **along with approval for reduction in hazardous chemical burning (also no source**
7 **reference). Lastly, commenter was concerned about the lack of initial testing dates**
8 **for boilers (page 98) “to be alarming”, as well as why the test-date has been moved**
9 **to the third quarter (University of Utah).**

10
11 UDAQ Response to H-92: The UDAQ will focus specifically on the comments regarding
12 the University of Utah as the other comments are statements and not specific to an
13 individual source. Section IX.H.o.ii specifically lists the requirements for initial testing
14 for boilers. Boilers #4, #6, and #7 all have had initial testing completed. Boiler #9 has
15 yet to be constructed and will abide by the SIP requirement to be installed by December
16 31, 2019. An initial stack test will be performed within 180 days of initial startup for
17 Boiler #9. All future testing will be required once every three (3) years (see UDAQ
18 response to comment H-67). Testing being moved from the second to the third quarter of
19 calendar year 2019 has no consequence; it is merely allowing time for the construction of
20 the project to be completed.

1 **Compass Minerals**

2
3 **Comment Summary H-93: The commenter suggests that a representative useful life**
4 **be used and based upon the manufacturer specifications and specifics at the site**
5 **when analyzing BACT for determining cost effectiveness. They suggest a 20-year life**
6 **does not always reflect the usefulness of equipment in harsh environments.**
7

8 UDAQ Response to H-93: UDAQ agrees with the commenter, a 15-year life was utilizing
9 in determining the cost effectiveness of equipment at Compass Minerals, which is
10 appropriate given the harsh conditions that exist within the manufacturing process.
11
12

ITEM 7



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-091-18

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Thomas Gunter, Environmental Planning Consultant

DATE: December 17, 2018

SUBJECT: FINAL ADOPTION: Change in Proposed Rule R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.

On June 6, 2018, the Board proposed R307-110-17 for a 45 day public comment period. On October 3, 2018, the Board proposed the rule for an additional 30 day public comment period. No comments were received during either comment period. R307-110-17 is the rule that incorporates the new amendments to Part H into the State rules. If the Board adopts the amendments proposed to Part H, these amendments will become part of Utah's State Implementation Plan when the rule is finalized.

Recommendation: Staff recommends that the Board adopt change in proposed rule R307-110-17 as amended.

1 R307. Environmental Quality, Air Quality.

2 R307-110. General Requirements: State Implementation Plan.

3 ---

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

6 The Utah State Implementation Plan, Section IX, Control Measures
7 for Area and Point Sources, Part H, Emission Limits and Operating
8 Practices, as most recently amended by the Utah Air Quality Board on
9 January 2, 2019, pursuant to Section 19-2-104, is hereby incorporated
10 by reference and made a part of these rules.

11 ---

12
13 KEY: air pollution, PM10, PM2.5, ozone

14 Date of Enactment or Last Substantive Amendment: 2019

15 Notice of Continuation: January 27, 2017

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

ITEM 8



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-087-18

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Director

FROM: Sheila Vance, Environmental Scientist

DATE: December 17, 2018

SUBJECT: FINAL ADOPTION: Change in Proposed Rule R307-511. Oil and Gas Industry: Associated Gas Flaring.

On September 5, 2018, the Board approved for public comment new rule R307-511. The public comment period was held from October 1 to October 31, 2018. Written comments were received by the Utah Division of Air Quality (UDAQ). In responding to the comments received from the Western Energy Alliance, UDAQ is proposing to clarify the rule's definition of "Associated Gas." The additional language in the definition provides clarity and does not alter the intent of the rule as proposed. The following provides details on the comments received and UDAQ's response.

Written comments were received from two organizations, the Environmental Defense Fund (EDF) and Western Energy Alliance (WEA).

EDF Comments - Questions and comments excerpted from original document.

EDF Comment #1: Requiring Operators to Capture, Rather than Destroy, Associated Gas Prevents Emissions Associated with Flaring and Combustion

UDAQ Response: The intent of the proposed rule was to expand the ability of oil and gas sources to take advantage of the streamlined permitting process where they follow a set of rules rather than the permit application process. Therefore, the rule is based upon current control standards for such sources, and is not intended to apply additional requirements. In current operating permits, the requirement is to either capture the associated gas or control it. To require capture rather than destruction would be an additional requirement that is currently not required for the best available control technology (BACT) applied to these sources. No changes were made as a result of this comment.

EDF Comment #2: Strengthening the destruction removal efficiency for flares and combustion devices will reduce air pollution caused by inefficient flares

UDAQ Response: This comment is similar to the comments received by EDF on R307-508 and the UDAQ position has not changed. The proposed rule reflects NSPS OOOOa requirements for 95% control efficiency. Combustion devices are designed to meet a 98% control efficiency but do not actually meet that percentage due to the variability in field conditions and operations. The existing rule R307-501 Oil and Gas Industry: General Provisions has requirements for proper design and operation of air pollution control equipment. No changes were made as a result of this comment.

EDF Comment #3: To help ensure that the state restores healthy air to Duchesne and Uintah counties, and to minimize the waste of natural gas and boost royalties, we urge DEQ to take the following additional steps as well:

- Initiate a stakeholder process in conjunction with the Division of Oil, Gas and Mining (DOGM) to evaluate proven measures to concurrently reduce flaring and waste pursuant to the Oil and Gas Conservation Act's prohibition on waste.
- Initiate a stakeholder process to evaluate the potential for additional emissions reductions, including a robust alternative pathway in R307-509 that allows operators to use emerging leak detection methods such as continuous methane monitors, to comply with leak detection and repair requirement, and adding requirements that limit venting from pipelines, well maintenance activities, and pneumatic pumps.

DAQ Response: Thank you for these suggestions. UDAQ will continue to use the stakeholder process, as we have in the past, when the need for any future rulemaking arises.

Western Energy Alliance (WEA) Comments - Questions and comments excerpted from original document.

WEA Comment #1: While we understand the need to limit the time frame of the associated gas releases, our experience shows that there are unanticipated events outside the operator's control that may extend longer than 24 hours. Specifically, there are times when gas compressor stations have had a mechanical or maintenance shutdowns that lasts as long as three days. During these shutdowns, the gas from the well is routed to a flare when available, or vented through tank or separator pressure relief devices. Would this rule apply to the above situation considering the definition of "Associated Gas" specifically excludes "All gas from storage vessels and low pressure separators?"

UDAQ Response: In response to the example provided in WEA's comment, UDAQ would not agree that mechanical and maintenance shutdowns by downstream compressor stations would meet the definition of an emergency. UDAQ defines an "Emergency" as a "temporary, infrequent and unavoidable situation" and is "an unanticipated event or failure." It is our understanding that compressor stations are known to have several day shutdowns quite often. We view these shutdowns as part of the standard operating processes that are known to operators of well sites. Thus, as part of well site operations, a stationary or portable flare must be available for situations that disrupt the sales line. Therefore, we do not consider such situations as emergencies.

WEA also provided the example that during such events when a downstream compressor station is down due to maintenance or mechanical issues, gas may be routed to tank or separator pressure relief devices. The current proposed rule definition of "associated gas" excludes gas from storage vessels and low pressure separators. The proposed definition included the exclusion since R307-506 and R307-507 already apply to these emissions sources. These rules are based upon normal operations, meaning working,

breathing and flashing from day to day operations associated with tanks and separators. These are not designed to take the full output of the gas well product. Therefore, UDAQ will clarify the exclusion from the associated gas definition by amending R307-511-2 as follows:

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

Also, in providing clarification to the exclusion to the associated gas definition, UDEQ determined that a clarification was needed for R307-511-4 Associated Gas Flaring Requirements and editorial changes. The UDEQ would like to clarify the purpose of routing gas to a process unit. The following change is proposed for R307-5011-4:

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

Recommendation: Staff recommends that the Board adopt change in proposed rule R307-511 as amended.

1 **Appendix 1: Regulatory Impact Summary Table***

Fiscal Costs	FY 2019	FY 2020	FY 2021
State Government	\$0	\$0	\$0
Local Government	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0
Other Person	\$0	\$0	\$0
Total Fiscal Costs:	\$0	\$0	\$0
Fiscal Benefits			
State Government	\$0	\$0	\$0
Local Government	\$0	\$0	\$0
Small Businesses	\$0	\$0	\$0
Non-Small Businesses	\$0	\$0	\$0
Other Persons	\$0	\$0	\$0
Total Fiscal Benefits:	\$0	\$0	\$0
Net Fiscal Benefits:	\$0	\$0	\$0

2 *This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they
 3 will not be included in this table. Inestimable impacts for State Government, Local Government, Small
 4 Businesses and Other Persons are described above. Inestimable impacts for Non-Small Businesses are described
 5 below.

7 **Appendix 2: Regulatory Impact to Non-Small Businesses**

8 No non-small businesses are expected to be impacted by this
 9 rulemaking. Large industrial businesses are already required to
 10 maintain and utilize the controls that this rule would require.
 11 This rule will primarily apply to smaller oil and gas operations
 12 that are susceptible to releases of produced gas. Therefore,
 13 non-small businesses will not be impacted.

14 There are an inestimable amount of oil and gas extraction
 15 (extraction) small businesses (NAICS 2111) operating in Utah.
 16 These extraction sites can be included in the Utah oil and gas
 17 registration, but their total numbers are currently unknown.
 18 These businesses could experience a one-time fiscal cost of
 19 \$800-\$1,500 associated with purchasing and installing the
 20 required control devices. The full impact to these small
 21 businesses cannot be estimated because the lack of extraction
 22 site inventory and control equipment already installed at those
 23 sites is not available.

24 Regardless of the fiscal impact possible on these small
 25 extraction sites, there is also a possibility for these same
 26 sites to experience a one-time benefit associated with the

1 installation of the control devices. Sites identified as needing
2 to flare releases are likely required to be permitted. With the
3 recently passed rule that allows permitting by rule, these small
4 extraction sites will be eligible for the one-time permitting
5 cost of \$250 if they have the controls installed, as opposed to
6 the original one-time cost of \$2,300 to obtain a permit. That
7 equals a potential benefit of \$2,050. The amount saved through
8 the use of this rule is greater than the amount required to
9 purchase and install the controls.

10 The Executive Director of the Department of Environmental
11 Quality, Alan Matheson, has reviewed and approved this fiscal
12 analysis.

13
14 **R307. Environmental Quality, Air Quality.**

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

16 **R307-511-1. Purpose.**

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

19
20 **R307-511-2. Definitions.**

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

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

30 "Associated Gas" means the natural gas that is produced
31 from an oil well during ~~[normal]~~ production operations and is
32 either sold, re-injected, used for production purposes, vented
33 (rarely) or flared. ~~[All gas from storage vessels and low~~
34 ~~pressure separators is not associated gas]~~ Low pressure gas
35 associated with the working, breathing, and flashing of oil is
36 not considered associated gas under this definition and shall be
37 controlled in accordance with R307-506 and R307-507.

38
39 **R307-511-3. Applicability.**

40 (1) R307-511 applies to each producing well located at a well
41 site as defined in 40 CFR 60.5430a Subpart 0000a Standards of
42 Performance for Crude Oil and Natural Gas Production,
43 Transmission and Distribution.

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

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

1
2 **R307-511-4. Associated Gas Flaring Requirements.**

3 (1) Associated gas from a completed well shall either be routed
4 to a process unit for combustion, routed to a sales pipeline, or
5 routed to an operating VOC control device except for ~~[the~~
6 ~~following condition:~~

7 ~~(a) Under]~~emergency release situations as defined in R307-511-
8 2.

9
10 **R307-511-5. Recordkeeping.**

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

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

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

16
17 **KEY: air quality, nonattainment, offset**

18 **Date of Enactment or Last Substantive Amendment: 201[8]9**

19 **Authorizing, and Implemented or Interpreted Law: 19-2-104; 19-2-**
20 **108**

ITEM 9

Air Toxics



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQA-1027-18

MEMORANDUM

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: November 5, 2018

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – October 2018

Asbestos Demolition/Renovation NESHAP Inspections	8
Asbestos AHERA Inspections	54
Asbestos State Rules Only Inspections	2
Asbestos Notification Forms Accepted	211
Asbestos Telephone Calls	457
Asbestos Individuals Certifications Approved/Disapproved	72/0
Asbestos Company Certifications/Re-Certifications	4/2
Asbestos Alternate Work Practices Approved/Disapproved	6/0
Lead-Based Paint (LBP) Inspections	7
LBP Notification Forms Accepted	0
LBP Telephone Calls	72
LBP Letters Prepared and Mailed	10
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	0
LBP Individual Certifications Approved/Disapproved	20/0
LBP Firm Certifications Approved/Disapproved	12/0

Notices of Violation Sent	0
Compliance Advisories Sent	23
Warning Letters Sent	13
Settlement Agreements Finalized	7
Penalties Agreed to:	
Salt Lake County Housing and Community Development	\$ 3,750.00
Preservation Painting, Inc.	\$ 1,500.00
Michael Moyal	\$ 3,000.00
Andrew O'Farrell	\$ 2,125.00
Dave Orgill	\$ 3,000.00
Bliss Parsons	\$ 1,959.38
BTS, Inc.	<u>\$ 1,200.00</u>
Total	\$16,534.38



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQA-1149-18

MEMORANDUM

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: December 17, 2018

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – November 2018

Asbestos Demolition/Renovation NESHAP Inspections	19
Asbestos AHERA Inspections	20
Asbestos State Rules Only Inspections	6
Asbestos Notification Forms Accepted	123
Asbestos Telephone Calls	384
Asbestos Individuals Certifications Approved/Disapproved	53/0
Asbestos Company Certifications/Re-Certifications	3/9
Asbestos Alternate Work Practices Approved/Disapproved	15/0
Lead-Based Paint (LBP) Inspections	4
LBP Notification Forms Approved	1
LBP Telephone Calls	26
LBP Letters Prepared and Mailed	9
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	2
LBP Individual Certifications Approved/Disapproved	6/0
LBP Firm Certifications	9

Notices of Violation Sent	0
Compliance Advisories Sent	18
Warning Letters Sent	11
Settlement Agreements Finalized	3
Penalties Agreed to:	
AbateX Environmental Services, Inc.	\$ 375.00
DRL Enterprises, Inc.	\$ 328.79
Driggs Development, LLC	<u>\$ 225.00</u>
 Total	 \$ 928.79

Compliance



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQC-2387-18

MEMORANDUM

TO: Air Quality Board
FROM: Bryce C. Bird, Executive Secretary
DATE: November 15, 2018
SUBJECT: Compliance Activities – October 2018

Annual Inspections Conducted:

Major.....	4
Synthetic Minor	0
Minor	33

On-Site Stack Test Audits Conducted: 2

Stack Test Report Reviews: 40

On-Site CEM Audits Conducted: 0

Emission Reports Reviewed: 2

Temporary Relocation Requests Reviewed & Approved: 8

Fugitive Dust Control Plans Reviewed & Accepted:..... 147

Open Burn Permit Applications Completed 1,562

Soil Remediation Report Reviews: 5

¹Miscellaneous Inspections Conducted:..... 23

Complaints Received: 12

Breakdown Reports Received:.....	0
Compliance Actions Resulting From a Breakdown.....	0
Warning Letters Issued:	2
Notices of Violation Issued:.....	0
Compliance Advisories Issued:.....	3
No Further Action Letters Issued.....	6
Settlement Agreements Reached:	5
R. Chapman Construction – Harmston Plant.....	\$37,667.00
Kilgore Companies – Parley’s Aggregate Pit	\$1,414.00
Dematic	\$359.00
Newfield Production	\$359.00
R. Chapman Construction – Lake Fork Pit.....	\$471.00

¹Miscellaneous inspections include, e.g., surveillance, level I inspections, VOC inspections, complaints, on-site training, dust patrol, smoke patrol, open burning, etc.



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQC-2486-18

MEMORANDUM

TO: Air Quality Board
FROM: Bryce C. Bird, Executive Secretary
DATE: December 10, 2018
SUBJECT: Compliance Activities – November 2018

Annual Inspections Conducted:

Major..... 4
Synthetic Minor 3
Minor 41

On-Site Stack Test Audits Conducted: 3

Stack Test Report Reviews: 40

On-Site CEM Audits Conducted: 0

Emission Reports Reviewed: 6

Temporary Relocation Requests Reviewed & Approved: 6

Fugitive Dust Control Plans Reviewed & Accepted:..... 150

Open Burn Permit Applications Completed 263

Soil Remediation Report Reviews: 4

¹Miscellaneous Inspections Conducted:..... 23

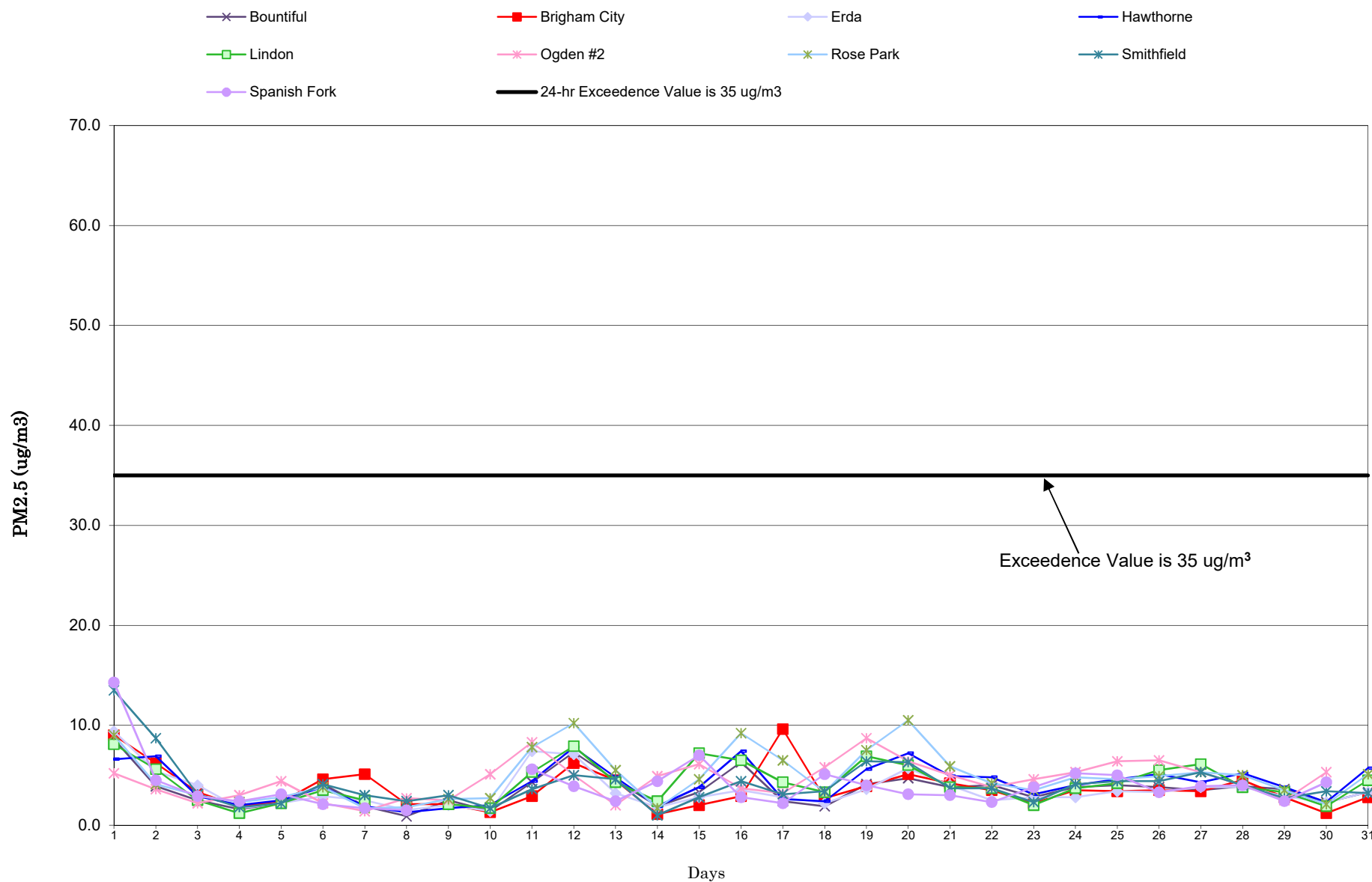
Complaints Received: 15

Breakdown Reports Received:.....	0
Compliance Actions Resulting From a Breakdown.....	0
Warning Letters Issued:	3
Notices of Violation Issued:.....	0
Compliance Advisories Issued:.....	5
No Further Action Letters Issued.....	4
Settlement Agreements Reached:	3
Crescent Point Energy	\$583.00
Wesco Operating	\$710.00
Action Target	\$729.00

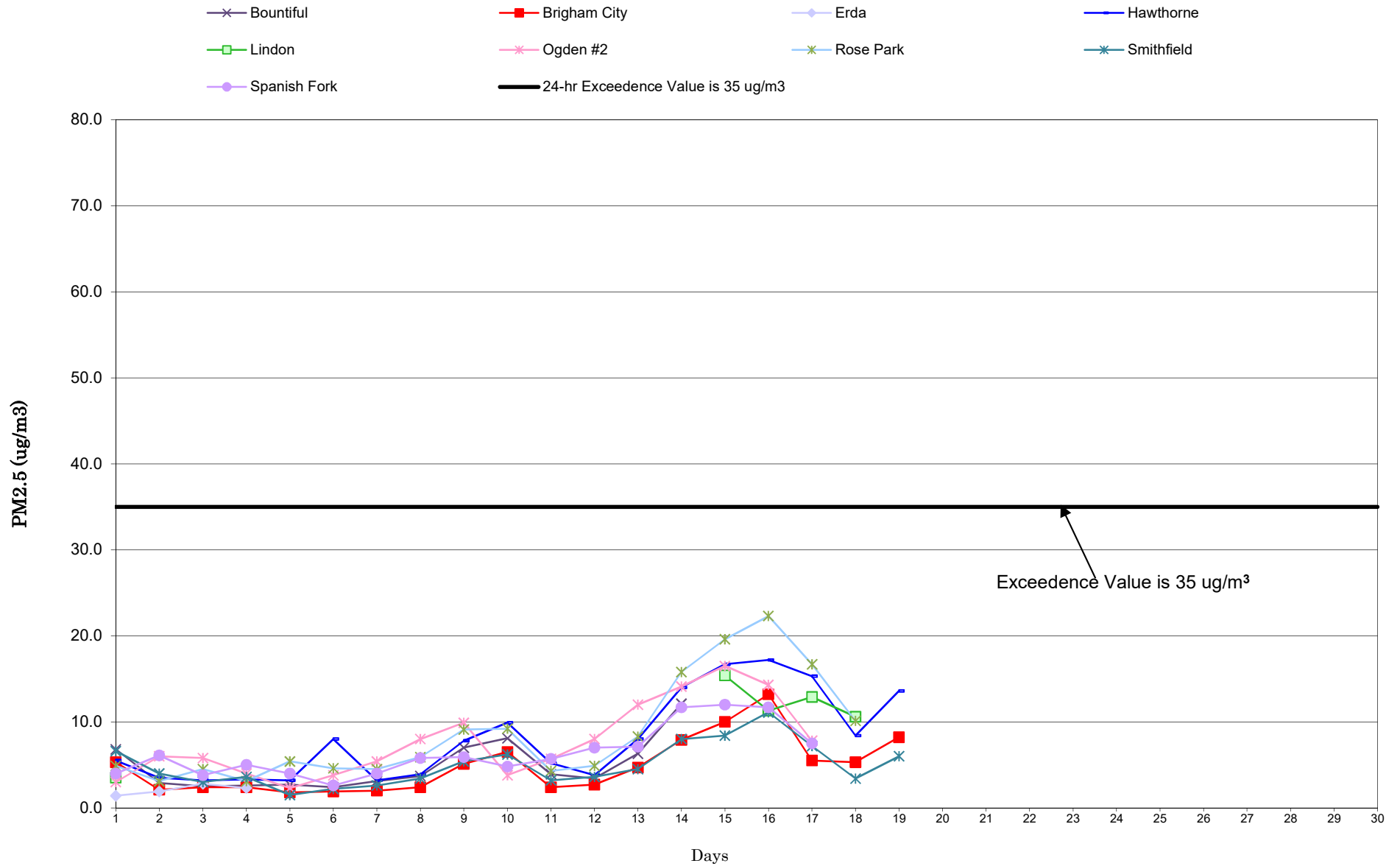
¹Miscellaneous inspections include, e.g., surveillance, level I inspections, VOC inspections, complaints, on-site training, dust patrol, smoke patrol, open burning, etc.

Air Monitoring

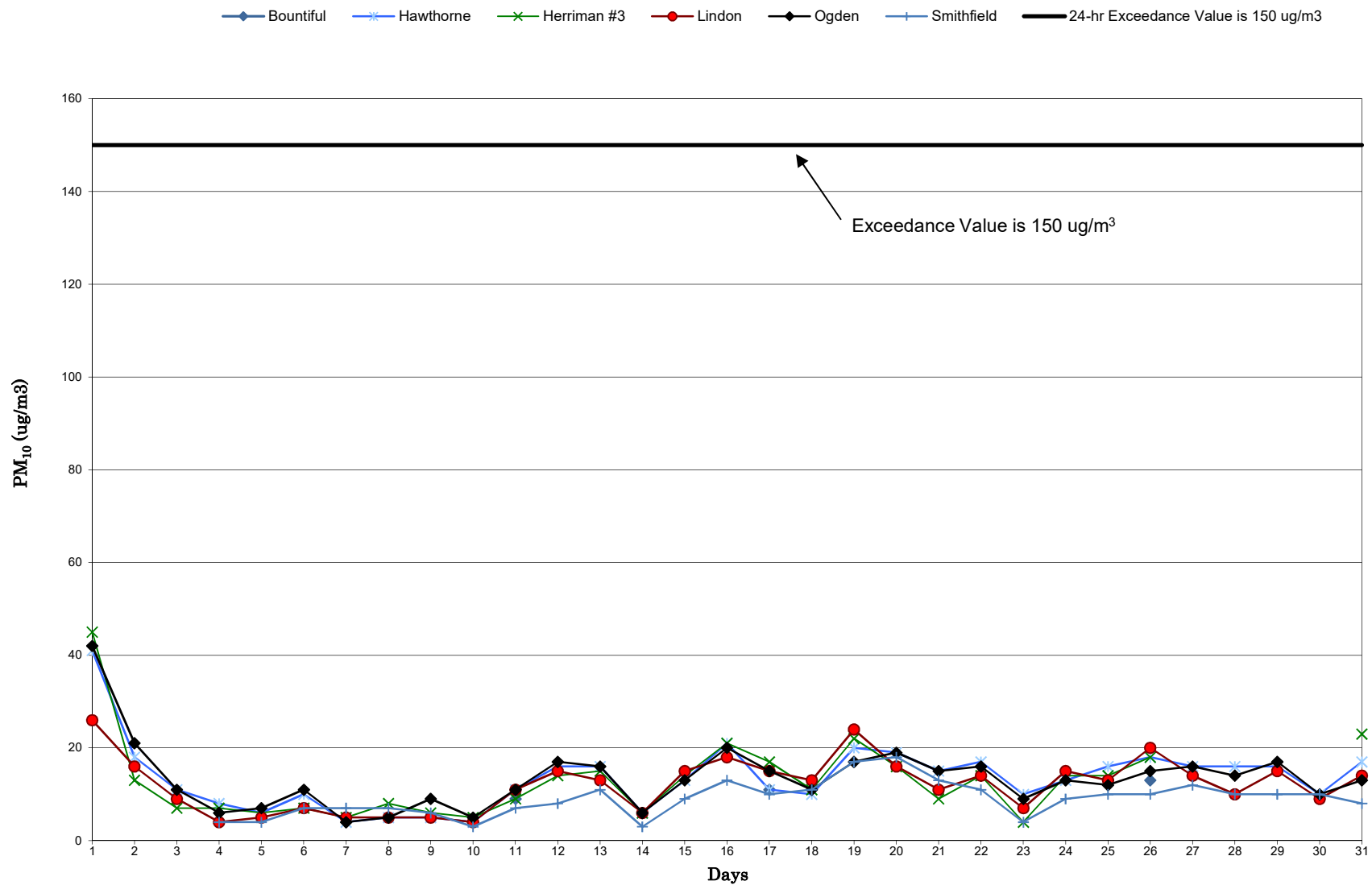
Utah 24-Hr PM2.5 Data October 2018



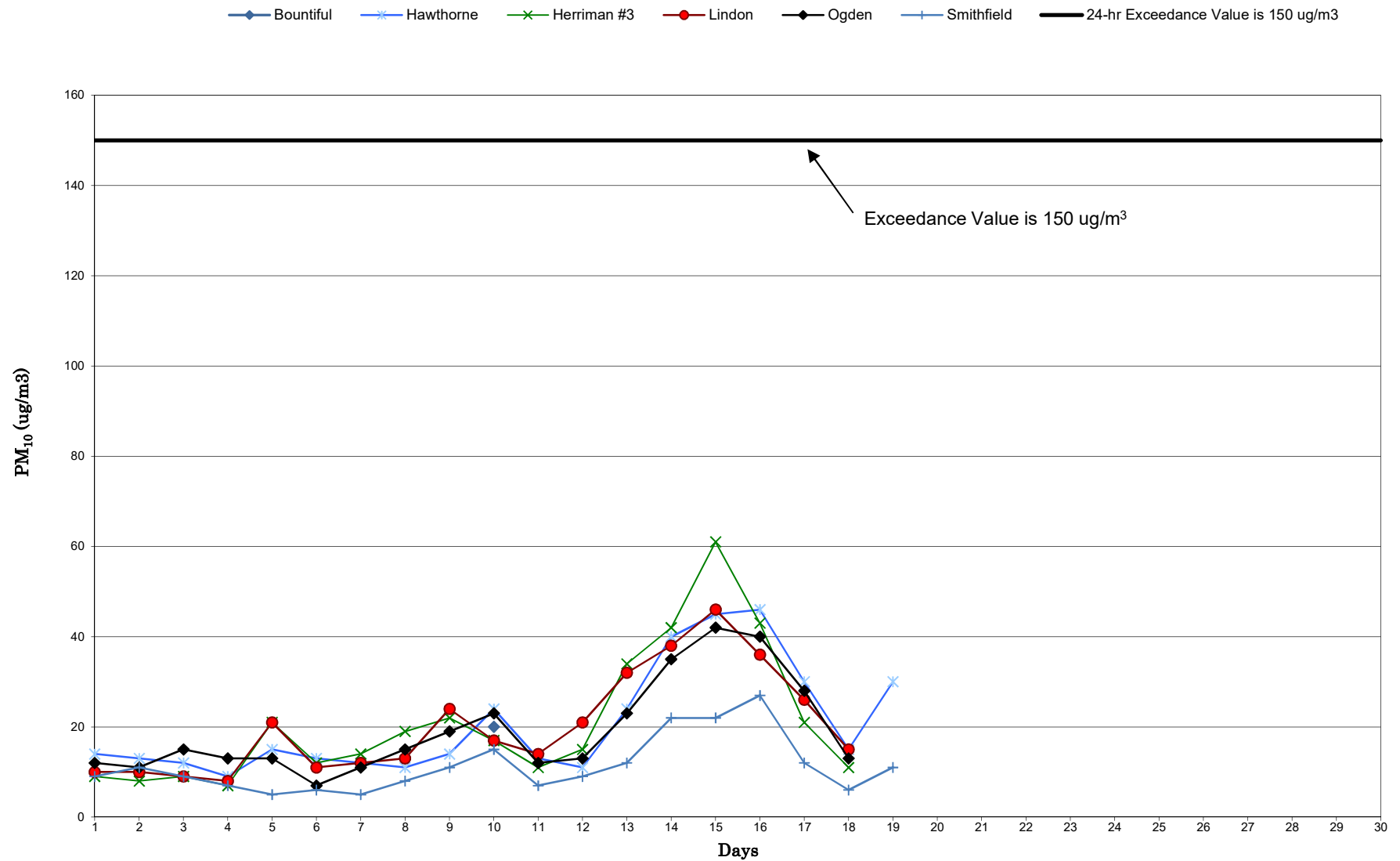
Utah 24-Hr PM2.5 Data November 2018



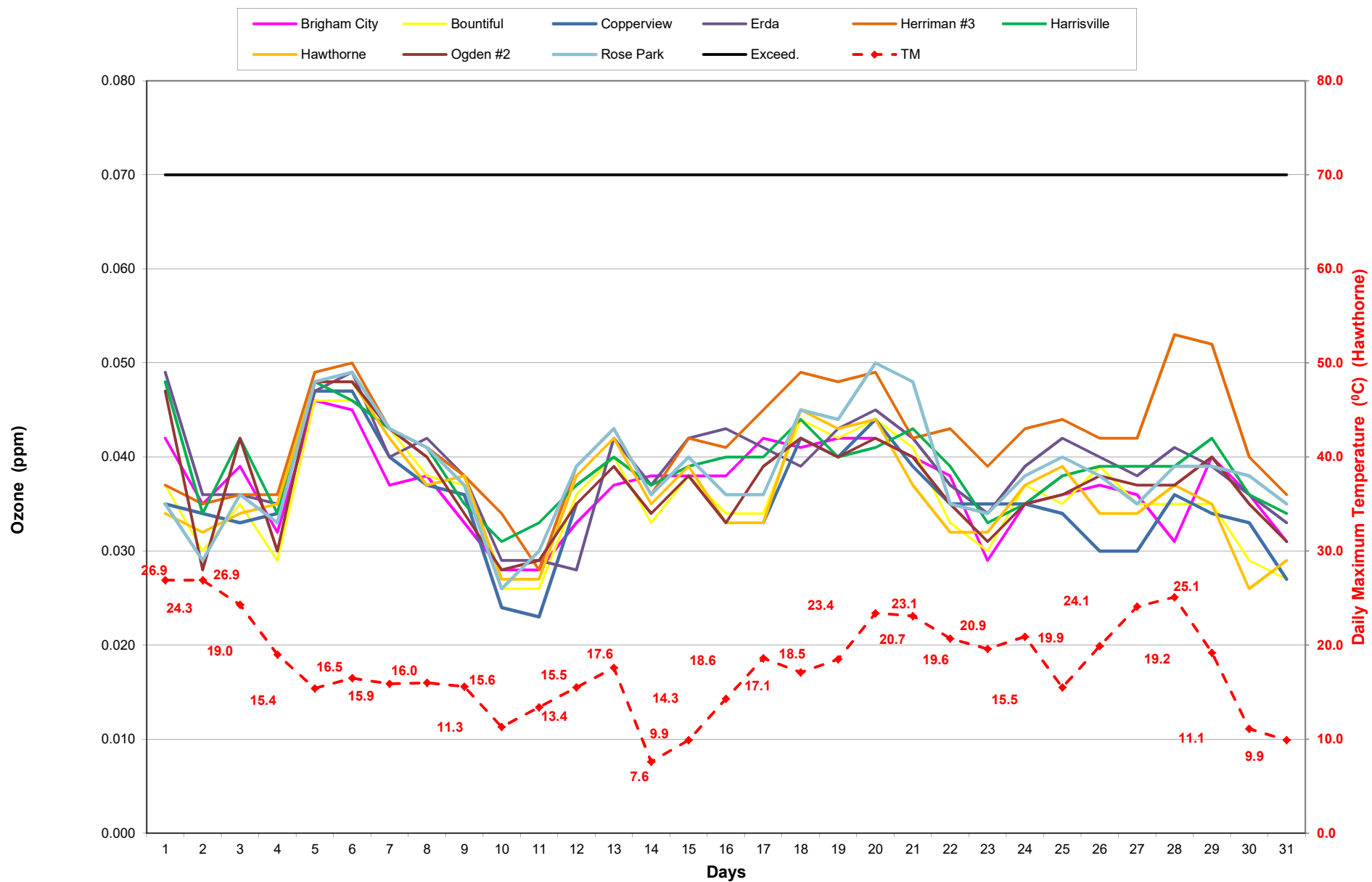
Utah 24-hr PM₁₀ Data October 2018



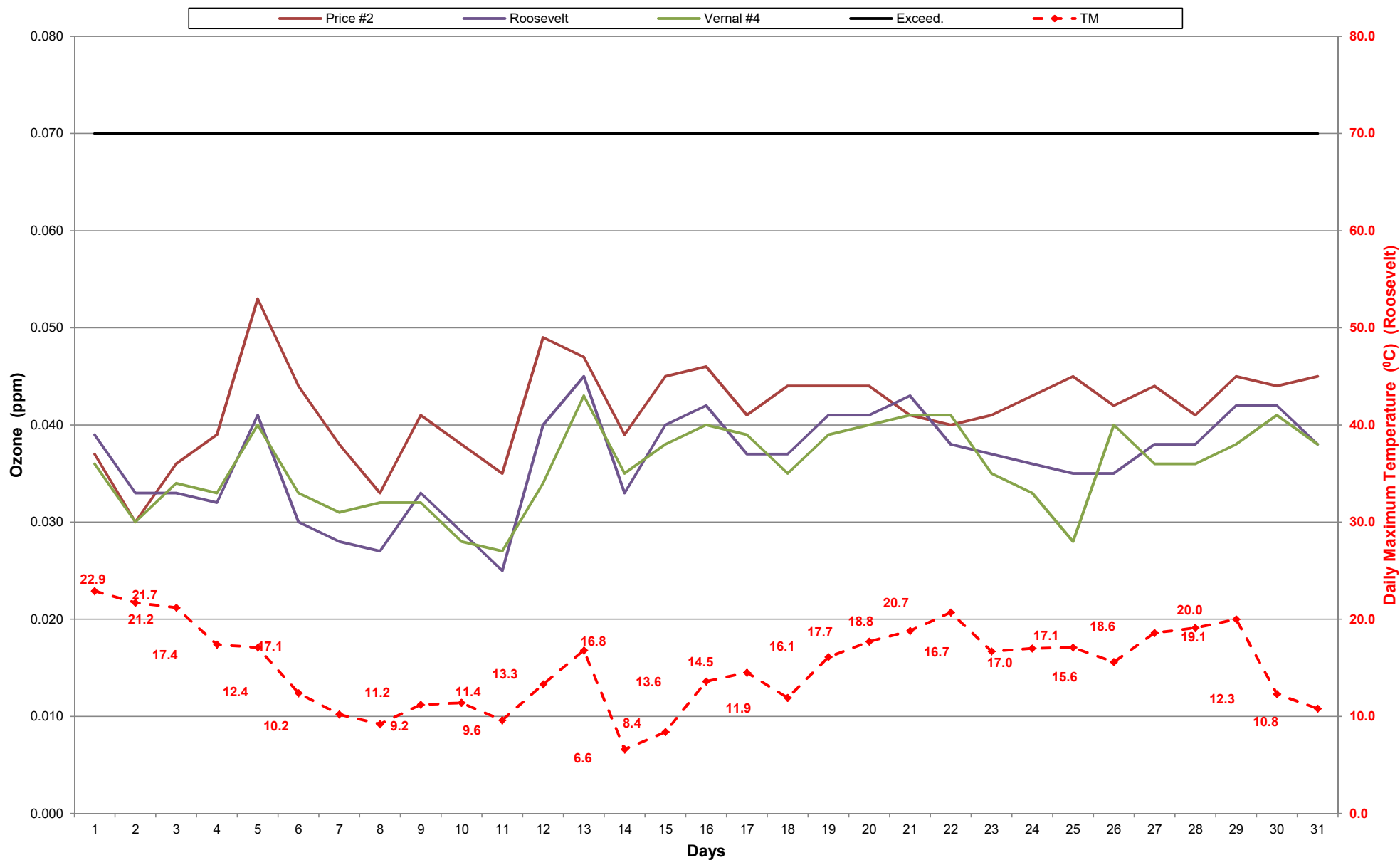
Utah 24-hr PM₁₀ Data November 2018



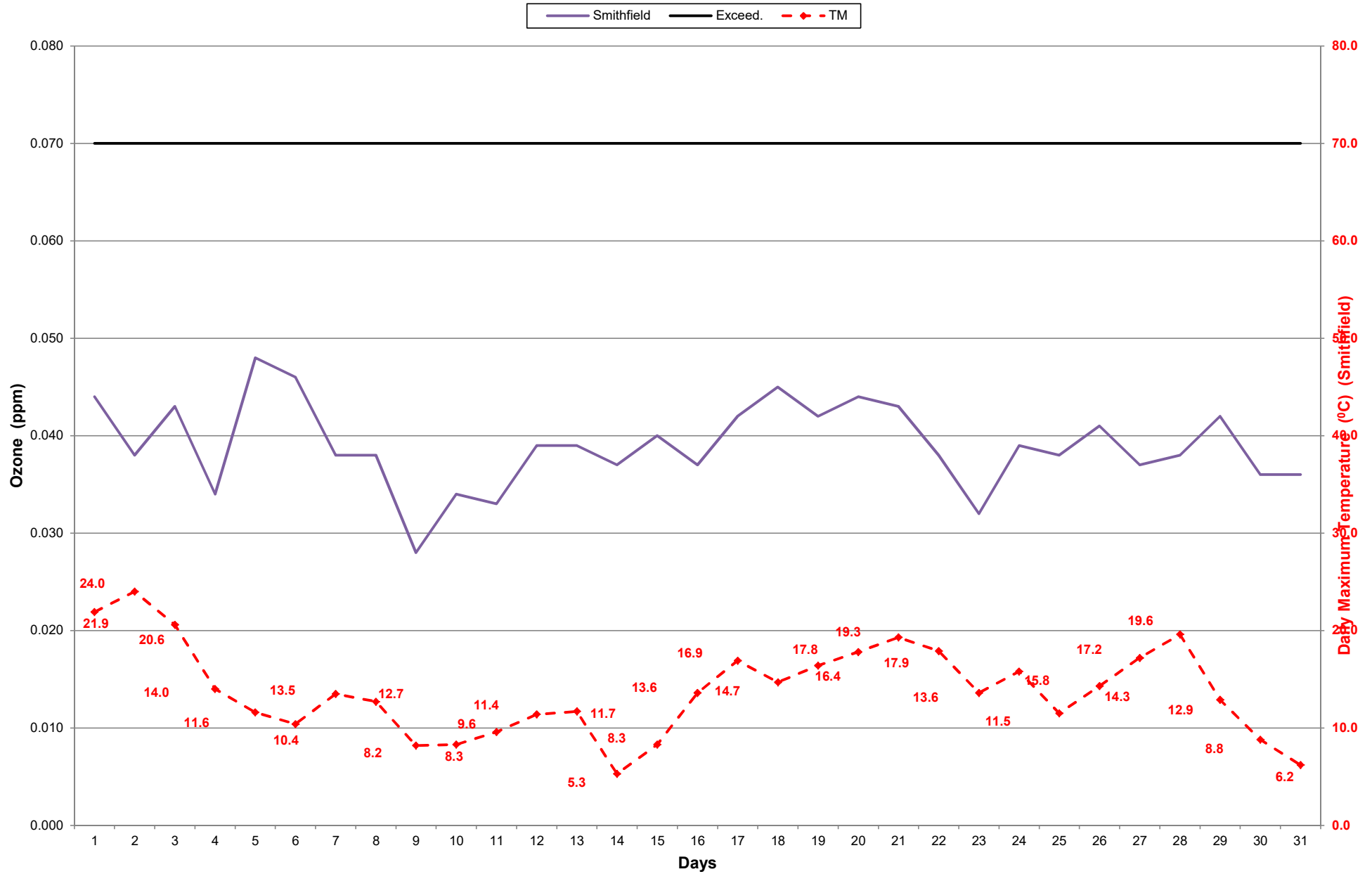
Highest 8-hr Ozone Concentration & Daily Maximum Temperature October 2018



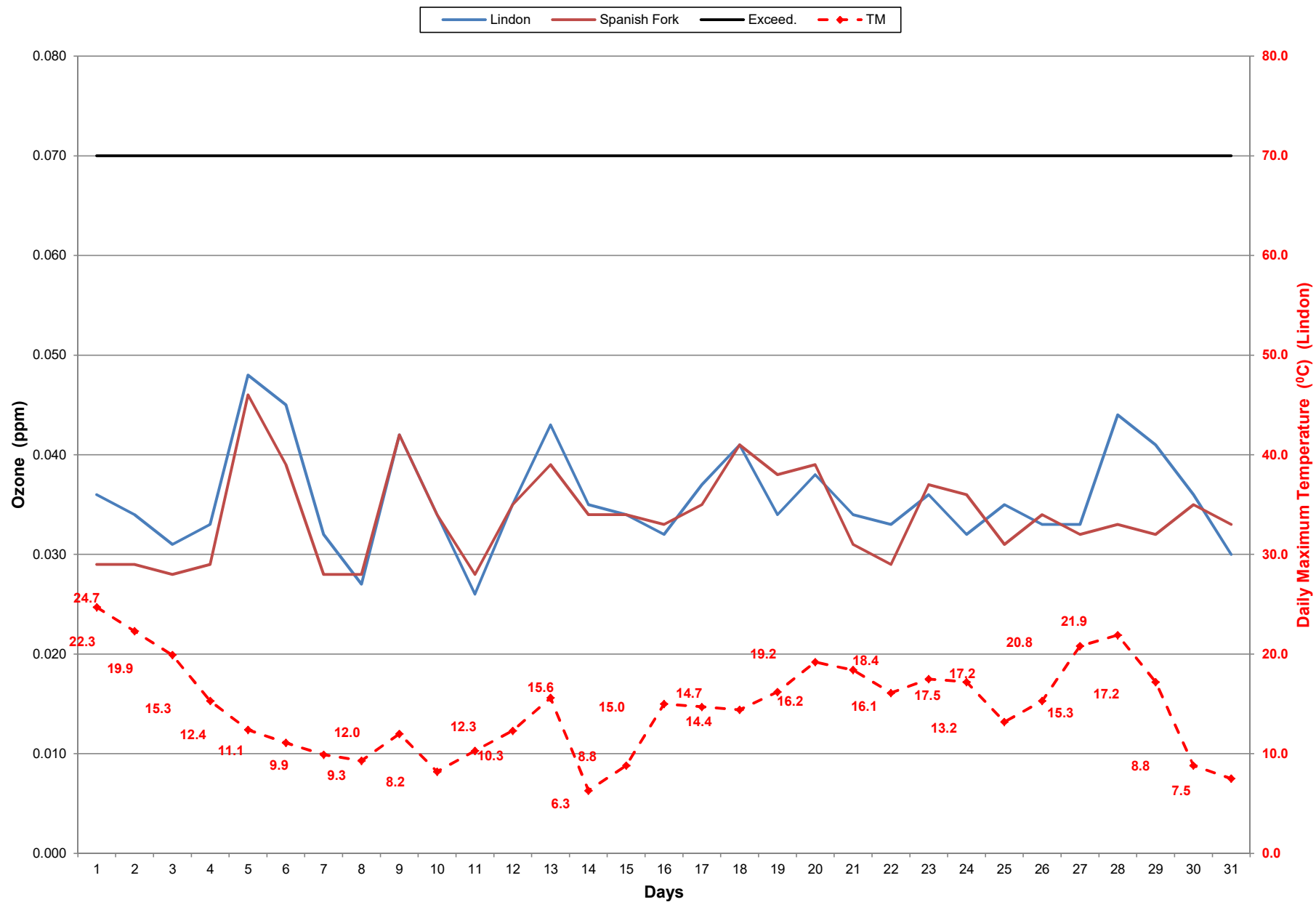
Highest 8-hr Ozone Concentration & Daily Maximum Temperature October 2018



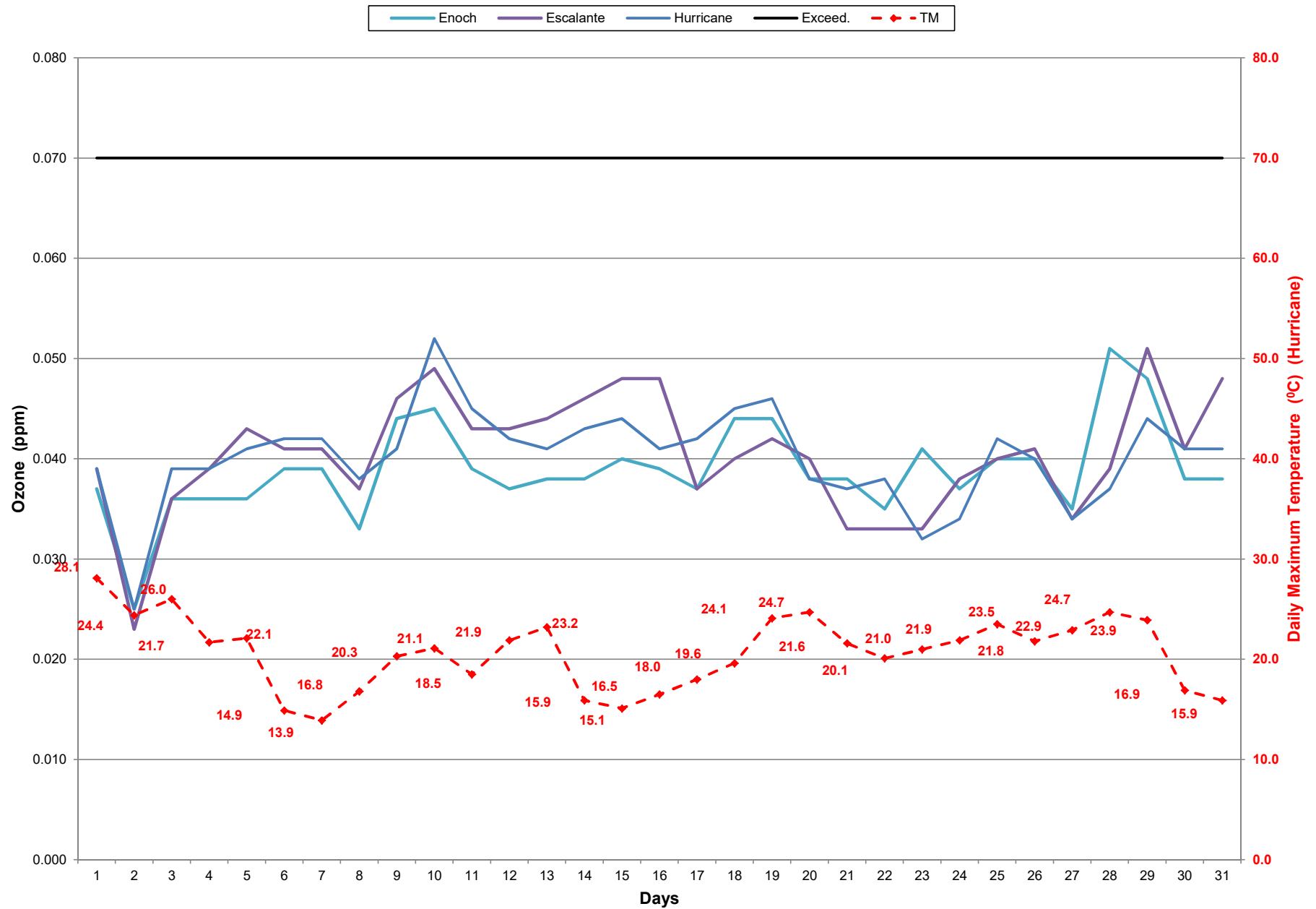
Highest 8-hr Ozone Concentration & Daily Maximum Temperature October 2018



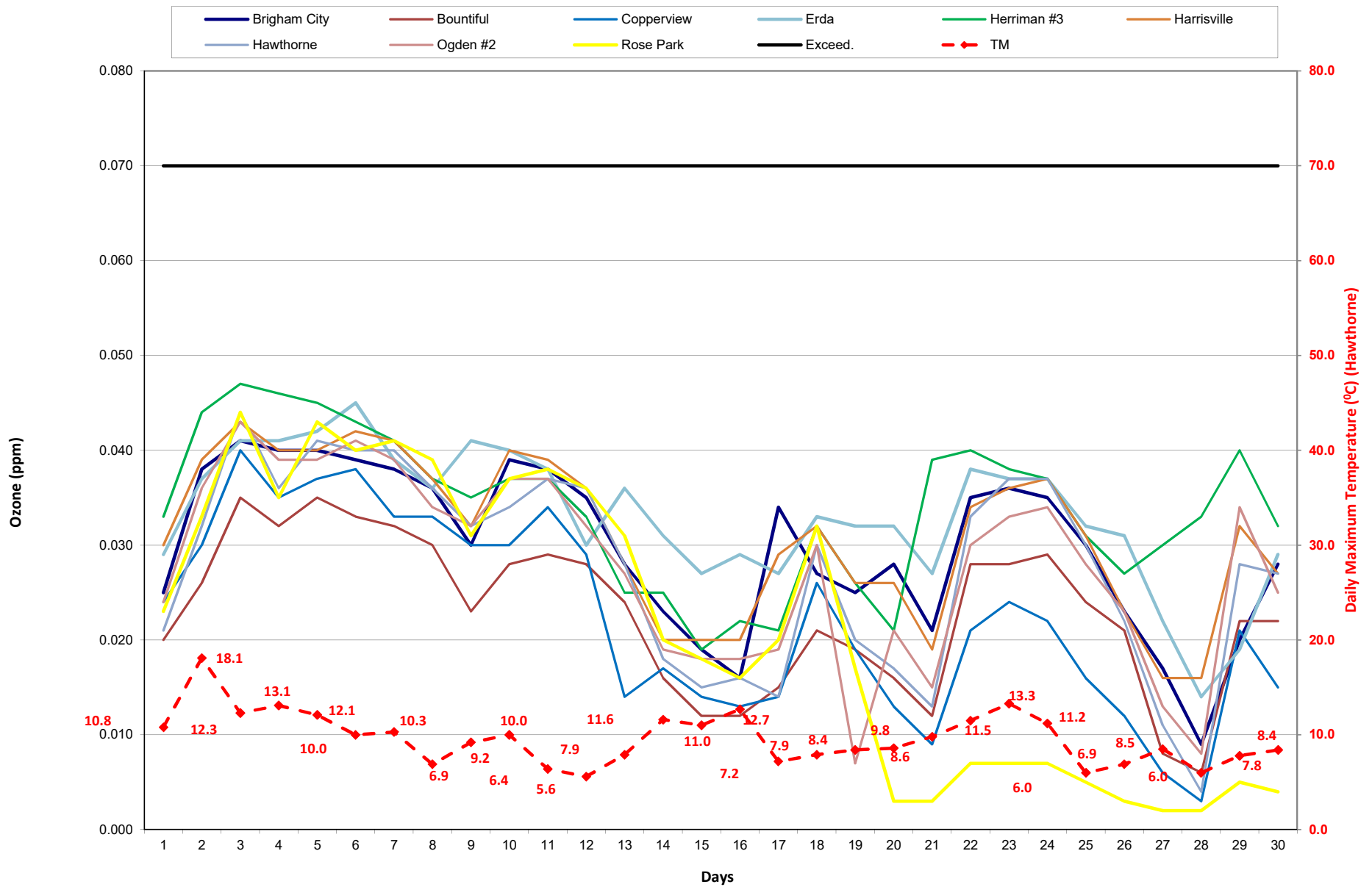
Highest 8-hr Ozone Concentration & Daily Maximum Temperature October 2018



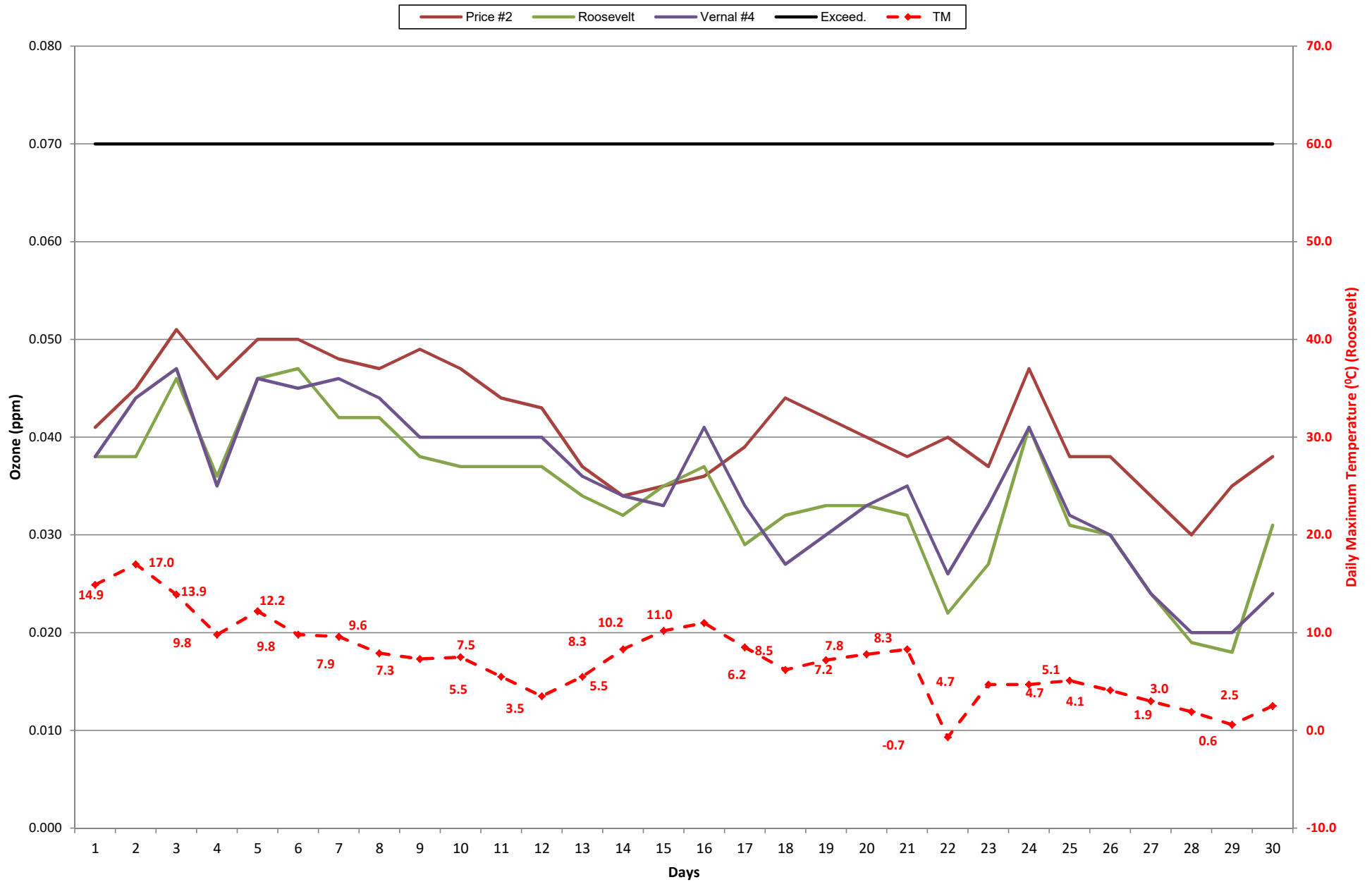
Highest 8-hr Ozone Concentration & Daily Maximum Temperature October 2018



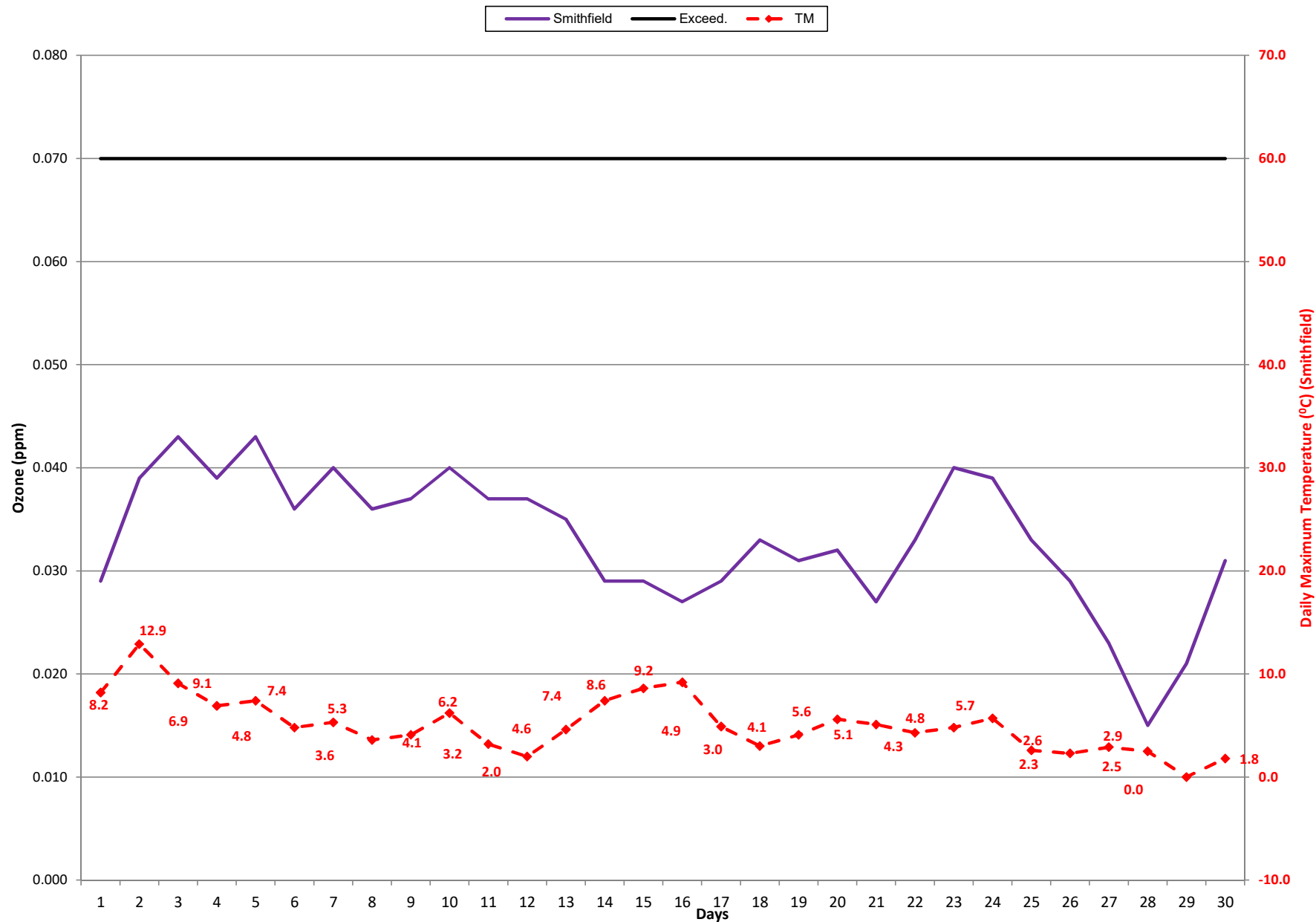
Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2018



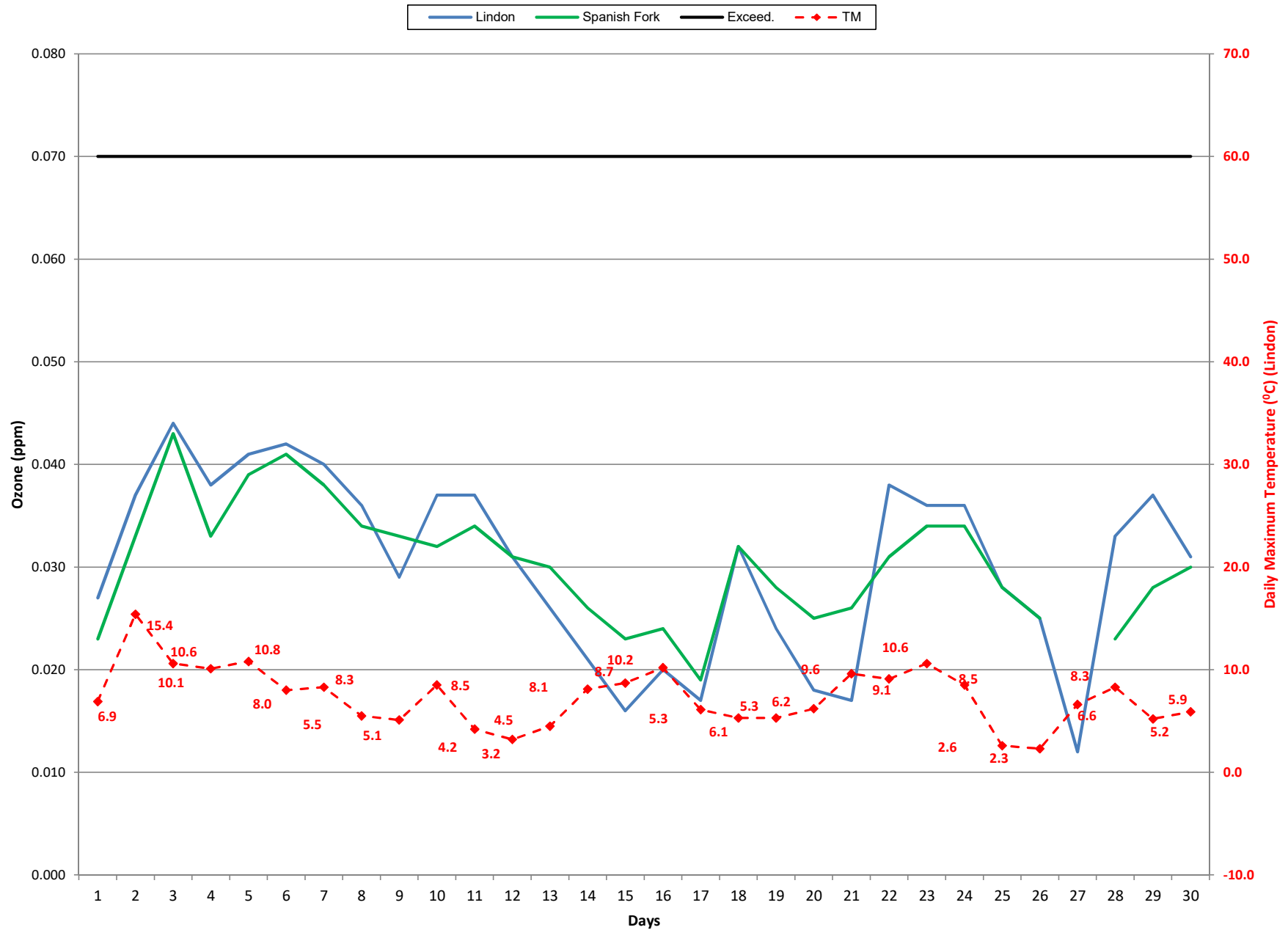
Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2018



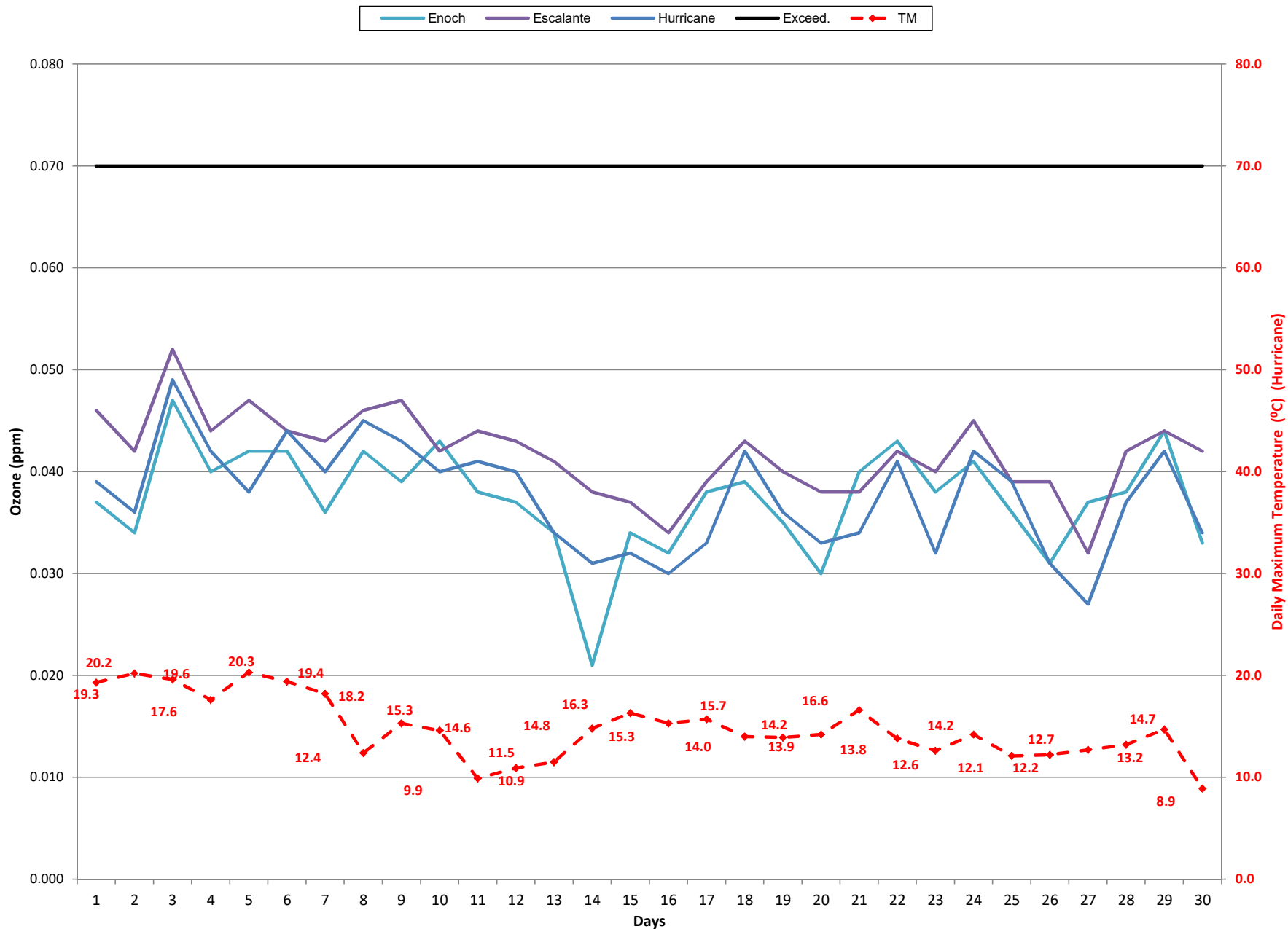
Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2018



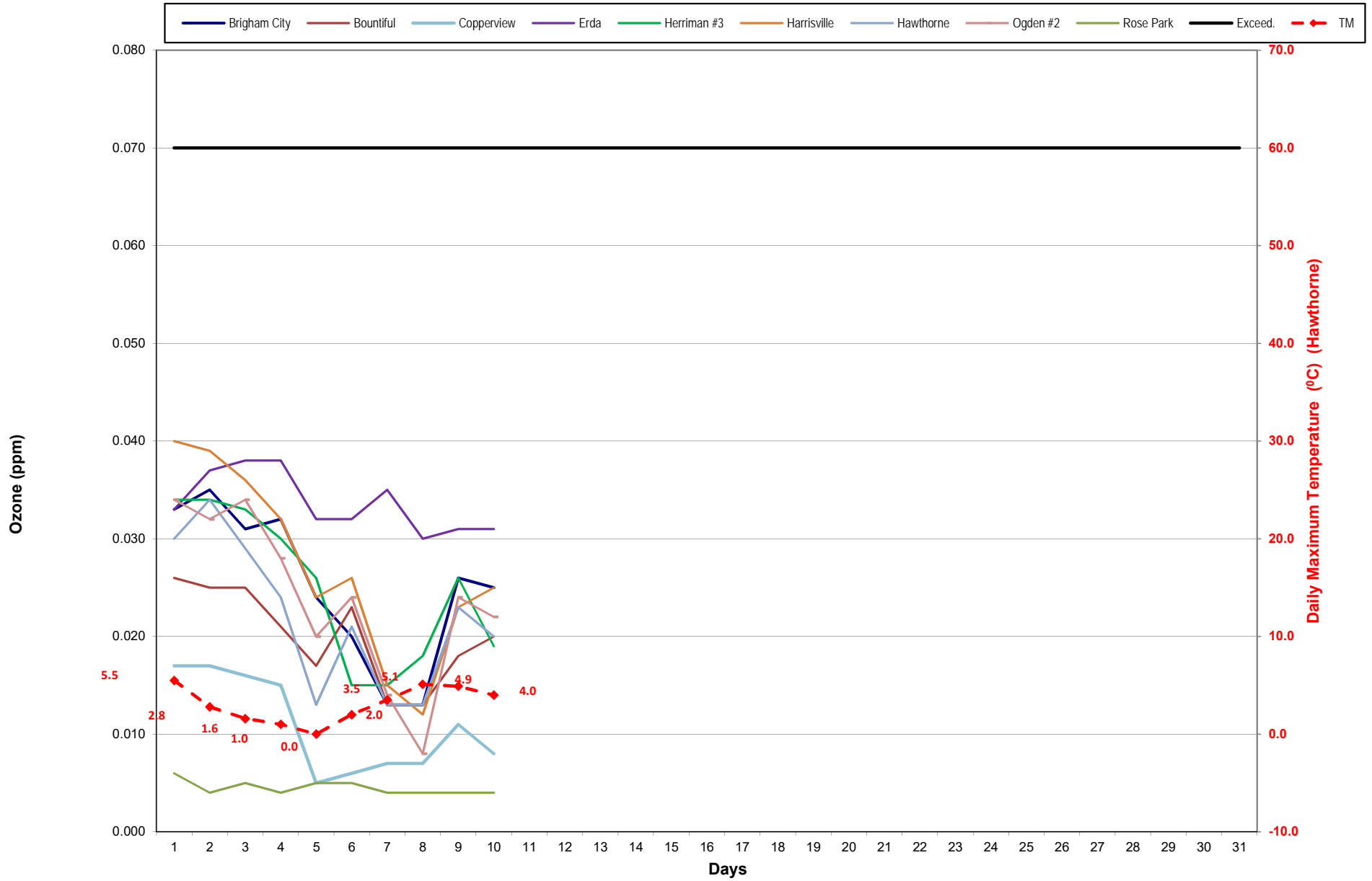
Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2018



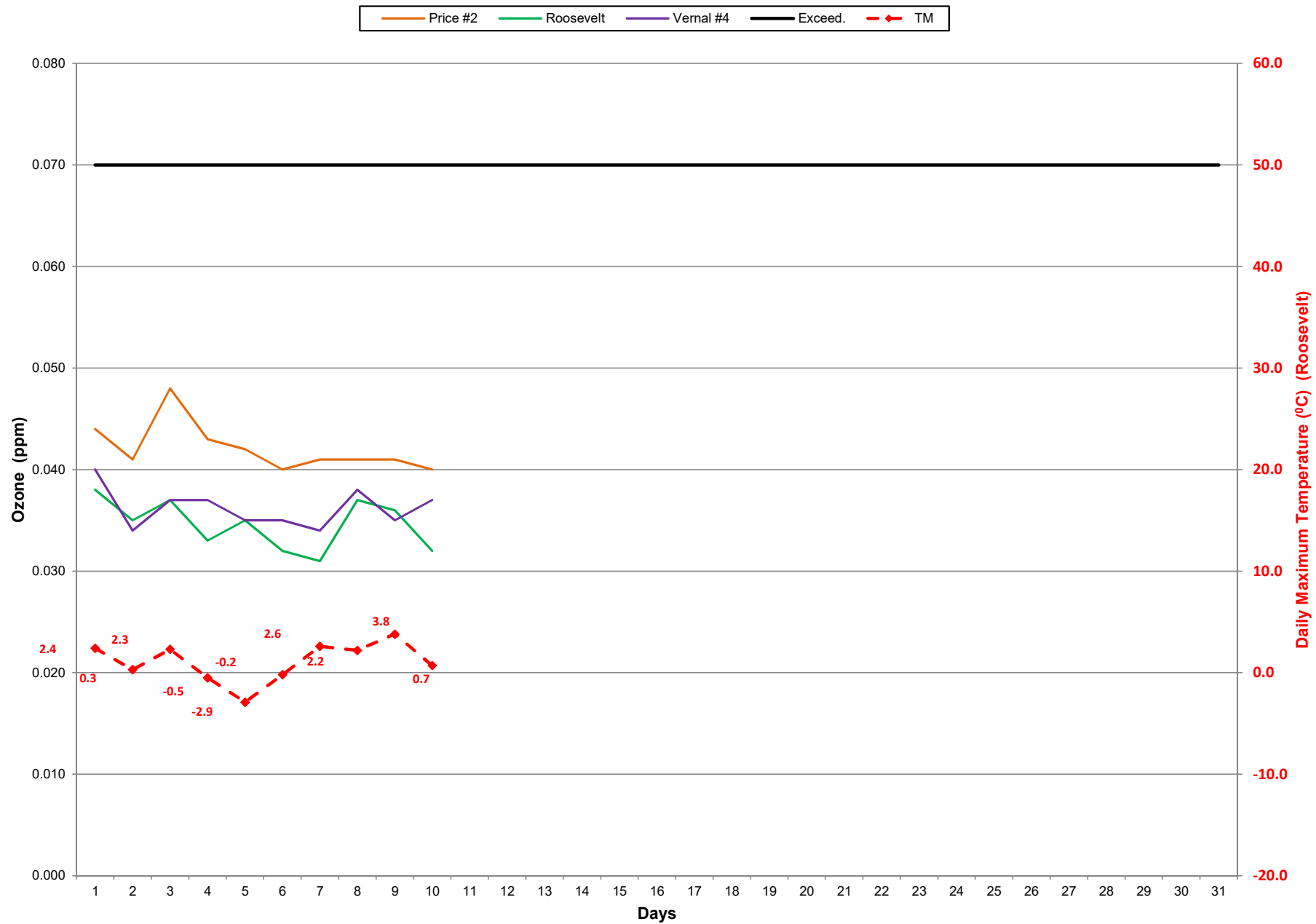
Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2018



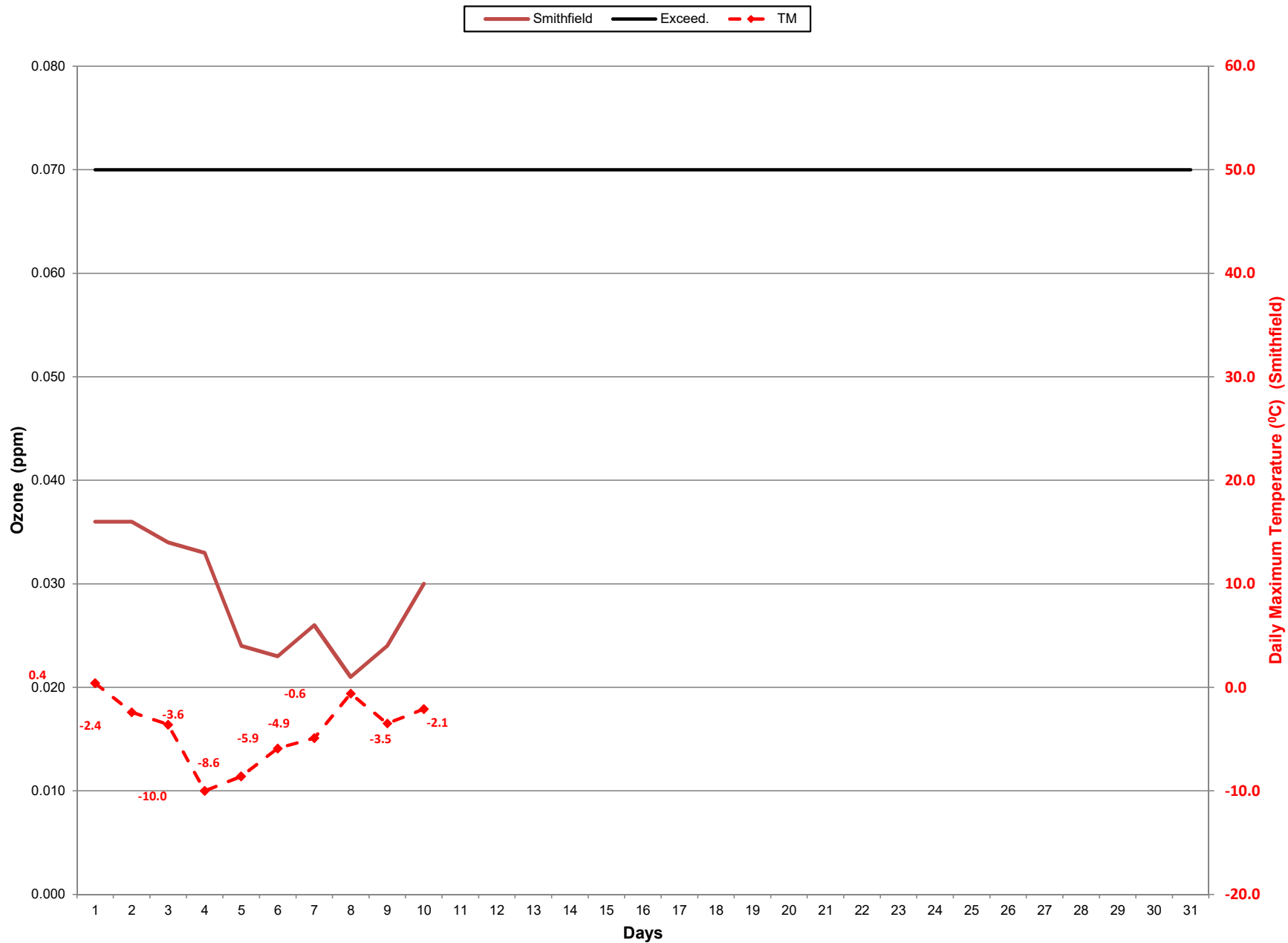
Highest 8-hr Ozone Concentration & Daily Maximum Temperature December 2018



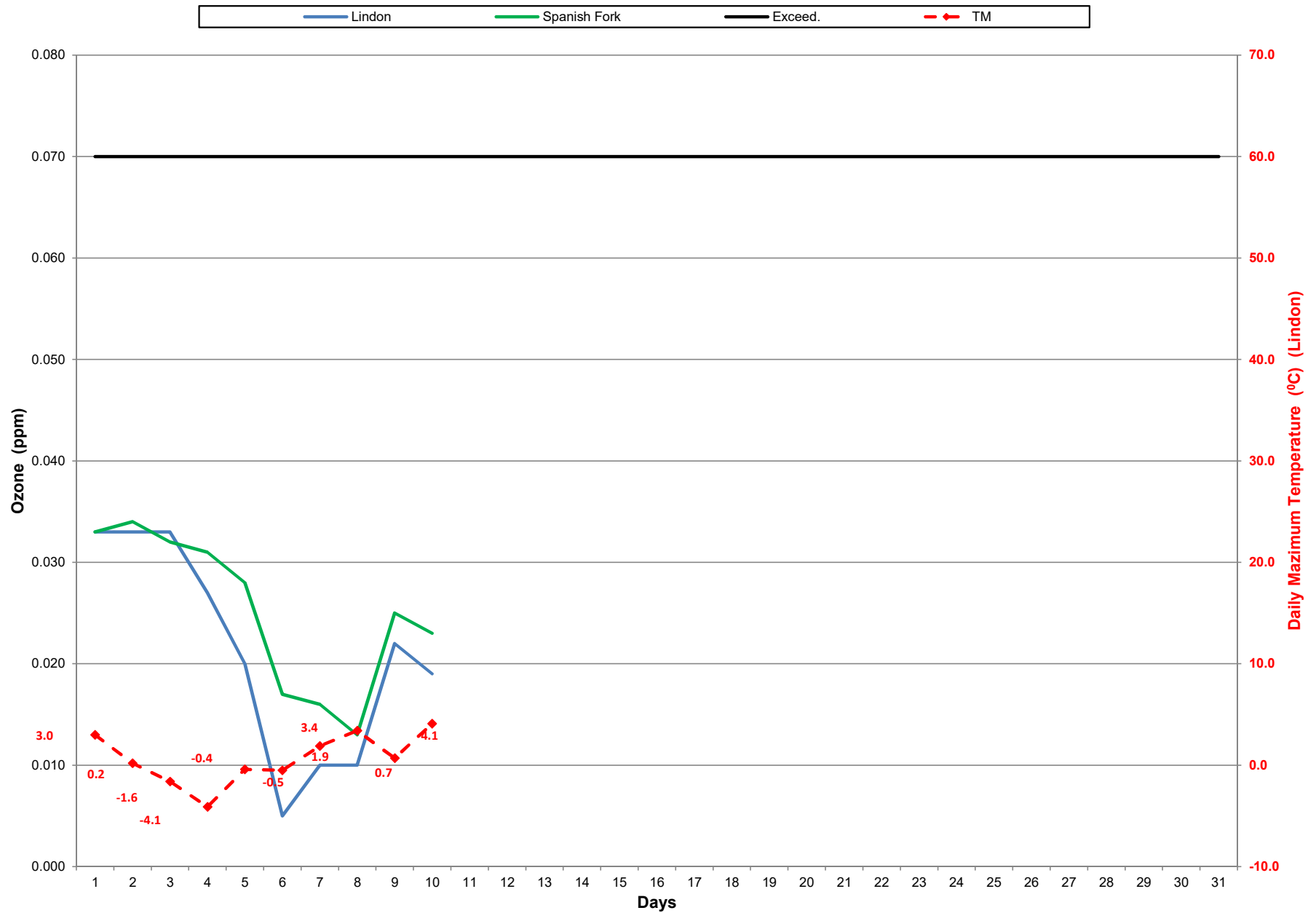
Highest 8-hr Ozone Concentration & Daily Maximum Temperature December 2018



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