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
Stephen C. Sands II, *Chair*
Kerry Kelly, *Vice-Chair*
Alan Matheson
Erin Mendenhall
Robert Paine III
Arnold W. Reitze Jr
Michael Smith
William C. Stringer
Karma M. Thomson
Bryce C. Bird,
Executive Secretary

DAQ-041-16a

UTAH AIR QUALITY BOARD MEETING

FINAL AGENDA

Wednesday, September 7, 2016 - 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116

I. Call-to-Order

II. Annual Election of the Board Chair and Vice-Chair. Presented by Bryce Bird.

III. Date of the Next Air Quality Board Meeting: October 5, 2016

IV. Approval of the Minutes for August 3, 2016, Board Meeting.

V. Five Year Review: R307-121. General Requirements: Clean Air and Efficient Vehicle Tax Credit. Presented by Ryan Stephens.

VI. Final Adoption: New Rule R307-124. General Requirements: Conversion to Alternative Fuel Grant Program. Presented by Ryan Stephens.

VII. Propose for Public Comment: Amend R307-302. Solid Fuel Burning Devices. Presented by Ryan Stephens.

VIII. Propose for Public Comment: Amend SIP Subsection IX. Part H: Emission Limits and Operating Practices. Specifically Proposed for Amendment are the PM2.5 Requirements in Subparts H. 11, 12, and 13, and the PM10 Requirements in Subpart H.2. Presented by Bill Reiss.

IX. Propose for Public Comment: Amend R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits. Presented by Ryan Stephens.

X. Propose for Public Comment with Department Fee Schedule: Operating Permit Program Fee for Fiscal Year 2018. Presented by David Beatty.

XI. Informational Items.
- A. Ozone Nonattainment Area Designation Recommendation. Presented by Sheila Vance and Jay Baker.
- B. Western Energy Alliance. Presented by Lowell Braxton.
- C. Air Toxics. Presented by Robert Ford.
- D. Compliance. Presented by Jay Morris and Harold Burge.
- E. Monitoring. Presented by Bo Call.
- F. Other Items to be Brought Before the Board.

In compliance with the American with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Ashley Nelson, Office of Human Resources at (801) 536-4413 (TDD 903-3978).

ITEM 4

State of Utah

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UTAH AIR QUALITY BOARD MEETING
August 3, 2016 – 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116

DRAFT MINUTES

DRAFT

I. Call-to-Order

Steve Sands called the meeting to order at 1:30 p.m.

Board members present: Karma Thomson, Alan Matheson, Steve Sands, Arnold Reitze, Michael Smith, and Robert Paine

Excused: Kerry Kelly, Erin Mendenhall, and William Stringer

Executive Secretary: Bryce Bird

II. Date of the Next Air Quality Board Meeting: September 7, 2016

III. Approval of the Minutes for June 1, 2016, Board Meeting.

Mr. Reitze corrected the wording on page four of five in the last sentence of paragraph three to read, "For other states that were originally in the GCVTC that was not the case and they opted out of the section 309."

- Arnold Reitze motioned to approve the minutes with noted change. Karma Thomason seconded. The Board approved the motion with Robert Paine absent for this agenda item.

IV. Final Adoption: Amend R307-101-3. Version of Code of Federal Regulations Incorporated by Reference. Presented by Ryan Stephens.

Ryan Stephens, Environmental Planning Consultant at DAQ, stated that this rule amendment was proposed because of the need to periodically update references to the Code of Federal Regulations (CFR). The reference to the July 1, 2014, CFR was changed to July 1, 2015. All of the relevant changes to the CFR were summarized in the material provided in the Board packet. A public comment period was held, no comments were received, and no hearing was requested. Staff recommends that the Board adopt the amendments to R307-101-3.

- Michael Smith motioned to approve final adoption of R307-101-3, Version of Code of Federal Regulations Incorporated by Reference. Karma Thomson seconded. The Board approved the motion with Robert Paine absent for this agenda item.

V. Final Adoption: R307-210. Stationary Sources. Presented by Ryan Stephens.

Ryan Stephens, Environmental Planning Consultant at DAQ, stated that this rule was proposed because of the need to periodically update references to the CFR. The reference to the July 1, 2014, CFR was changed to July 1, 2015. All of the relevant changes to the CFR were summarized in the material provided in the Board packet. The Board also requested a summary of the changes to the oil and gas rules. Staff emailed the Board a copy of that summary in May, and it was also provided in the Board packet. A public comment period was held, no comments were received, and no hearing was requested. Staff recommends that the Board adopt the amendments to R307-210.

- Arnold Reitze motioned to approve final adoption of R307-210, Stationary Sources. Michael Smith seconded. The Board approved the motion with Robert Paine absent for this agenda item.

VI. Final Adoption: Amend R307-214. National Emission Standards for Hazardous Air Pollutants. Presented by Ryan Stephens.

Ryan Stephens, Environmental Planning Consultant at DAQ, stated that this rule was proposed because of the need to periodically update references to the CFR. The reference to the July 1, 2014, CFR was changed to July 1, 2015. All of the relevant changes to the CFR were summarized in the material provided in the Board packet. A public comment period was held, no comments were received, and no hearing was requested. Staff recommends that the Board adopt R307-214.

Robert Paine enters the meeting.

In discussion, there was concern that this might be a regulation that sources are not aware of. Staff responded that in the past DAQ has worked with the Division of Environmental Response and Remediation's (DERR's) underground storage tanks section by including requirements under the Clean Air Act in that section's newsletter. This may be an opportunity for DAQ to again include this requirement in the DERR's newsletter and also to make sure that affected facilities are made aware of these requirements.

- Karma Thomson motioned to approve final adoption of R307-214, National Emission Standards for Hazardous Air Pollutants. Arnold Reitze seconded. The Board approved unanimously.

VII. Informational Items.

A. 2015 Special Toxics Study Report. Presented by Roman Kuprov.

Roman Kuprov, Environmental Scientist in DAQ, gave a brief overview and answered questions from the Board on the 2015 air sampling study on toxics. The funding for the study included more frequent sampling at the Bountiful monitoring site and established two temporary sites in West Valley City and Lindon to collect more data. In the study, lead, formaldehyde, and methylene chloride were pollutants that stood out. Mr. Kuprov discussed each pollutant and charted the findings of the 2015 study. Possible reasons for

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elevated lead values may be current and past mining activity and impacts of former lead smelters operating in the area. Formaldehyde is a pollutant that is largely produced through secondary chemistry. As of 2012, Utah is the highest in the nation for formaldehyde in which the Bountiful location really stood out during the 2015 study. Self-reported emission numbers from the refineries seem to be too low to account for the current formaldehyde levels. Oher possible sources may be near-primary source emitters of close precursors to formaldehyde or photochemical enhancement from the lake. The elevated levels of methylene chloride are comparable to most urban areas and are usually associated with sources that use large amounts of solvents. Bountiful also showed elevated levels of methylene chloride compared to Lindon and West Valley. Going forward, DAQ has applied for a grant for a follow-up study to look specifically into distribution of formaldehyde around the Bountiful area. The grant would allow the setup of 28 passive samplers with some met stations in Bountiful to locate possible hot spots for formaldehyde. As with formaldehyde, DAQ will continue to work on locating possible sources of the elevated levels of methylene chloride and lead.

B. 2016 Rulemaking Calendar Update. Presented by Mark Berger.

Mark Berger, Air Quality Policy Section Manager at DAQ, gave an update of rulemaking DAQ is planning for the remainder of 2016. For September there are four rules planned. One of those rules, R307-302, staff took the Board's suggestions from the June Board meeting and feel that the rule will be ready to present to the Board for public comment. Bill Reiss will present a package of PM_{10} maintenance plan and $PM_{2.5}$ State Implementation Plan (SIP) amendments to Part H to the Board, which he will explain in more detail later on the agenda. By September staff should have a better idea of what Utah's ozone nonattainment designation recommendations to EPA will be. There are no pending items for October or November at this time. In December, staff plans to bring final adoptions to the Board from the proposals approved in September. Other rules for potential future amendments are 11 area source coatings rules and R307-335 which are in anticipation for a serious designation for $PM_{2.5}$. Those rules currently meet reasonable available control technology (RACT) requirements but for purposes of a serious designation they may need to be adjusted to meet best achievable control technology (BACT). A final potential rule is an oil and gas permit by rule in which DAQ continues to work with stakeholders and staff will continue to update the Board on its progress.

C. Regional Haze State Implementation Plan / Federal Implementation Plan Update. Presented by Mark Berger.

Mark Berger, Air Quality Policy Section Manager at DAQ, stated that EPA issued a final decision on the alternative to best available retrofit technology (BART) plan that the Board approved and DAQ submitted to EPA in June 2015. In EPA's final rule dated July 5, 2016, EPA disapproved the majority of Utah's alternative to BART plan and instead implemented a federal implementation plan which basically means that Hunter and Huntington power plants have to install selective catalytic reduction technologies by 2021. Mr. Berger briefly described how the regional haze program is structured and explained the reasons for EPA's disapproval of Utah's alternative to BART for NO_x and how EPA came to their decision. Going forward, Utah does have the opportunity to revise the SIP and propose a BART alternative that is clearly better than BART. PacifiCorp has announced plans to file a lawsuit contesting EPA's decision and Utah's Attorney General's Office is also looking at legal options for the state. DAQ is committed to work with EPA and Rocky Mountain to agree and to find a technology that can be implemented by 2018.

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D. PM State Implementation Plan Update. Presented by Bill Reiss.

Bill Reiss, Environmental Engineer at DAQ, stated that in September DAQ will propose a package of PM_{10} maintenance plan and $PM_{2.5}$ SIP amendments to Part H emission limitations to the Board. Staff priorities are mainly working toward approval of the three moderate area $PM_{2.5}$ SIPs with an emphasis on the Logan SIP, and working towards approval of the PM_{10} maintenance plans that were submitted last year. DAQ continues to work closely with EPA as they work through its review of these SIPs,

Part H is central to both of the PM SIPs and working on the final clean-up of Part H is a step towards approval. A few of the remaining clean-up items for $PM_{2.5}$ date back to the comments prepared in October 2014 addressing the draft Subpart 4 SIPs. DAQ addressed those last year in the PM_{10} plan and now the paperwork for $PM_{2.5}$ needs to mirror the PM_{10} revisions where appropriate. In addition, a revision to the $PM_{2.5}$ compliance schedule for Compass Minerals is being proposed and also proposing a revision to the PM_{10} conditions for baghouses at Kennecott's Copperton concentrator.

Upcoming will be the $PM_{2.5}$ re-classifications and the serious area $PM_{2.5}$ SIPs. The implementation rule has been signed by EPA but not published yet in the Federal Register. The implementation rule establishes the requirements that DAQ should have followed in 2014 but did not know about. There may be some additional issues that weren't addressed in 2014 that may come out and will need to be brought back to the Board for clean-up because of misalignment with what DAQ did and what is in the final implementation requirement for $PM_{2.5}$. This will then establish what needs to be done for the serious area classification and SIP requirements that will come in the future. The re-classification of the three areas is expected shortly and there will not be much time to complete those SIPs.

E. Volkswagen Settlement Update. Presented by Glade Sowards.

Glade Sowards, Environmental Scientist at DAQ, stated that in July 2016 the Department of Justice published in the Federal Register a proposed settlement that partially resolves alleged violations of the Clean Air Act by Volkswagen of the sale of approximately 500,000 model year 2009 to 2015 2.0 diesel engines equipped with "defeat devices." The proposed settlement was opened for a 30-day public comment period before final approval. Mr. Sowards explained several requirements that Volkswagen must follow under the proposed settlement. Some of which include removing from commerce or modifying affected vehicles, offer buyback or lease termination options, invest an additional $2 billion to promote zero emission vehicles, and pay $2.7 billion into a mitigation fund to reduce emissions of NO_x. Under the proposal, Utah will receive $32,356,471 for eligible mitigation actions. Mr. Sowards continued that final settlement is anticipated this fall with trustee selection anticipated by mid-2017. Governor Herbert has appointed Utah DEQ as lead agency. The mitigation fund must be spent or obligated within 10 years of the trust effective date and the remainder to be reallocated among beneficiaries who have spent/obligated 80% of the fund. He listed several eligible mitigation actions and stated that the projects will be selected based on emissions reduction benefits.

F. Air Toxics. Presented by Robert Ford.

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

DRAFT

H. Monitoring. Presented by Bo Call.

Bo Call, Air Monitoring Section Manager at DAQ, updated the Board on the monitoring graphs, noting there were no exceedances on July 4. The ozone season began in June and there were several spikes over the ozone standard in the Wasatch Front starting at the end of June. During that period the Uinta Basin, Smithfield, Utah County, Hurricane, and the Cache Valley areas did not come close to the ozone standard. July's ozone trend was the same for those areas. Beginning in August the Uinta Basin had hourly values that exceeded the ozone standard and just recently had 8-hour values that got right at 70 parts per billion.

I. Other Items to be Brought Before the Board.

Meeting adjourned at 2:39 p.m.

DRAFT

ITEM 5

State of Utah

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Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-039-16

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Ryan Stephens, Rules Coordinator

DATE: August 24, 2016

SUBJECT: Five-Year Review: R307-121. General Requirements: Clean Air and Efficient Vehicle Tax Credit.

Utah Code Section 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. It is to verify that the rule is still necessary and allowed under state and federal statutes. As part of this process, the Division is required to identify any comments on the rule that were received since the last five-year review. This process is not the time to revisit those comments or to respond to them.

DAQ has completed a five year review for R307-121. The results of this review are found in the attached Five-Year Notice of Review and Statement of Continuation form.

Staff Recommendation: Staff recommends that the Board continue R307-121 by approving the attached form to be filed with the Division of Administrative Rules.

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R3407. Environmental Quality, Air Quality.
R307-121. General Requirements: Clean Air and Efficient Vehicle Tax Credit.
R307-121-1. Authorization and Purpose.

(1) This rule is authorized by Sections 59-7-605 and 59-10-1009. These statutes establish criteria and definitions used to determine eligibility for an income tax credit.

(2) R307-121 establishes procedures to provide proof of purchase or lease, in accordance with 59-7-605(3)(b) or 59-10-1009(3)(b), to the director for an OEM vehicle, qualifying electric motorcycle, or the conversion of a motor vehicle or special mobile equipment for which an income tax credit is allowed under Sections 59-7-605 or 59-10-1009.

R307-121-2. Definitions.

The following additional definitions apply to R307-121.

"Air quality standards" means air quality standards as defined in Subsection 59-7-605(1)(a) and 59-10-1009(1)(a).

"Clean fuel" means clean fuel as defined in Subsection 19-1-402(1).

"Clean fuel vehicle" means clean fuel vehicle as defined in Subsection 19-1-402(2).

"Conversion equipment" means a package that may include fuel, ignition, emissions control, and engine components that are modified, removed, or added to a motor vehicle or special mobile equipment to make that motor vehicle or equipment eligible for the tax credit.

"Motor Vehicle" means a motor vehicle as defined in 41-1a-102.

"Original equipment manufacturer(OEM) vehicle" means original equipment manufacturer(OEM) as defined in Subsection 19-1-402(8).

"Original purchase" means original purchase as defined in Subsection 59-7-605(1)(g) and 59-10-1009(1)(g).

"Qualifying electric motorcycle" means qualifying electric motorcycle as defined in 59-7-605(1)(h) or 59-10-1009(1)(h).

"Qualifying electric vehicle" means qualifying electric vehicle as defined in 59-7-605(1)(i) or 59-10-1009(1)(i).

"Qualifying plug-in hybrid vehicle" means qualifying plug-in hybrid vehicle as defined in 59-7-605(1)(j) or 59-10-1009(1)(j).

"Window Sticker" means the label required by United States Code Title 15 Sections 1231 and 1232, as effective January 3, 2012.

R307-121-3. Proof of Purchase to Demonstrate Eligibility for New OEM Natural Gas, Propane, Qualifying Electric or Qualifying Plug-in Hybrid Vehicles.

To demonstrate that an OEM natural gas, propane, qualifying electric, or qualifying plug-in hybrid motor vehicle is eligible for the tax credit, proof of purchase shall be made in accordance with 59-7-605(3)(b) or 59-10-1009(3)(b), by submitting the following documents to the director:

(1)(a) a copy of the motor vehicle's window sticker, which includes its Vehicle Identification Number (VIN), or equivalent manufacturer's documentation showing that the motor vehicle is an

OEM natural gas, propane, qualifying electric or qualifying plug-in hybrid vehicle, or

(b) a signed statement by either an Automotive Service Excellence (ASE)-certified technician or Canadian Standards Association (CSA) America CNG Fuel System Inspector that includes the VIN, the technician's ASE or CSA America certification number, and states that the motor vehicle is an OEM natural gas, propane, qualifying electric or qualifying plug-in hybrid vehicle;

(2) an original or copy of the purchase order, customer invoice, or receipt that includes the name of the taxpayer seeking the credit, the name of the seller of the motor vehicle, the VIN, purchase date, and price of the motor vehicle;

(3) a copy of the current Utah vehicle registration in the name of the taxpayer seeking the credit;

(4) an original or copy of the odometer disclosure statement required in Utah Code Annotated Title 41 Chapter 1a Section 902 for the motor vehicle that was acquired as an original purchase; and

(5) the underhood identification number or engine group of the motor vehicle.

R307-121-4. Proof of Purchase to Demonstrate Eligibility for New Qualifying Electric Motorcycle.

To demonstrate that a qualifying electric motorcycle is eligible for the tax credit, proof of purchase shall be made in accordance with 59-7-605(3)(b) or 59-10-1009(3)(b), by submitting the following documents to the director:

(1)(a) a copy of the Manufacturer's Statement of Origin (MSO) or equivalent manufacturer's documentation showing that the motor vehicle is a qualifying electric motorcycle, or

(b) a signed statement by an Automotive Service Excellence (ASE)-certified technician that includes the VIN, the technician's ASE certification number, and states that the motorcycle is a qualifying electric motorcycle;

(2) an original or copy of the purchase order, customer invoice, or receipt that includes the name of the taxpayer seeking the credit, the name of the seller of the motor vehicle, the VIN, purchase date, and price of the motor vehicle;

(3) a copy of the current Utah vehicle registration in the name of the taxpayer seeking the credit; and

(4) an original or copy of the odometer disclosure statement required in Utah Code Annotated Title 41 Chapter 1a Section 902 for the motor vehicle that was acquired as an original purchase.

R307-121-5. Proof of Lease to Demonstrate Eligibility for New OEM Natural Gas, Propane, Qualifying Electric or Qualifying Plug-in Hybrid Vehicles.

To demonstrate that an OEM natural gas, propane, qualifying electric or qualifying plug-in hybrid vehicle is eligible for the tax credit, proof of lease shall be made in accordance with 59-7-605(3)(b) or 59-10-1009(3)(b), by submitting the following documents to the director:

(1)(a) a copy of the motor vehicle's window sticker, which includes its Vehicle Identification Number (VIN), or equivalent manufacturer's documentation showing that the motor vehicle is an OEM natural gas, propane, qualifying electric or qualifying plug-in hybrid vehicle; or

(b) a signed statement by either an Automotive Service Excellence (ASE)-certified technician or Canadian Standards Association (CSA) America CNG Fuel System Inspector that includes the VIN, the technician's ASE or CSA America certification number, and states that the motor vehicle is an OEM natural gas, propane, qualifying electric or qualifying plug-in hybrid vehicle;

(2) an original or copy of the lease agreement that includes the name of the taxpayer seeking the credit, the name of the lessor of the vehicle, the VIN, the beginning date of the lease, the value of the vehicle at the beginning of the lease, and the value of the vehicle at the end of the lease;

(3) a copy of the current Utah vehicle registration in the name of the taxpayer seeking the credit;

(4) an original or copy of the odometer disclosure statement required in Utah Code Annotated Title 41 Chapter 1a Section 902 for the motor vehicle that was acquired as an original purchase; and

(5) the underhood identification number or engine group of the motor vehicle.

R307-121-6. Proof of Lease to Demonstrate Eligibility for Qualifying Electric Motorcycle.

To demonstrate that a qualifying electric motorcycle is eligible for the tax credit, proof of lease shall be made in accordance with 59-7-605(3)(b) or 59-10-1009(3)(b), by submitting the following documents to the director:

(1)(a) a copy of the Manufacturer's Statement of Origin (MSO) or equivalent manufacturer's documentation showing that the motor vehicle is a qualifying electric motorcycle, or

(b) a signed statement by an Automotive Service Excellence (ASE)-certified technician that includes the VIN, the technician's ASE certification number, and states that the motorcycle is a qualifying electric motorcycle;

(2) an original or copy of the lease agreement that includes the name of the taxpayer seeking the credit, the name of the lessor of the vehicle, the VIN, the beginning date of the lease, the value of the vehicle at the beginning of the lease, and the value of the vehicle at the end of the lease;

(3) a copy of the current Utah vehicle registration in the name of the taxpayer seeking the credit; and

(4) an original or copy of the odometer disclosure statement required in Utah Code Annotated Title 41 Chapter 1a Section 902 for the motor vehicle that was acquired as an original purchase.

R307-121-7. Proof of Purchase to Demonstrate Eligibility for Motor Vehicles Converted to a Clean Fuel.

To demonstrate that a conversion of a motor vehicle to be fueled

by a clean fuel is eligible for the tax credit, proof of purchase shall be made, in accordance with 59-7-605(3)(b) or 59-10-1009(3)(b), by submitting the following documentation to the director:

(1) an original or copy of the purchase order, customer invoice, or receipt that includes the name of the taxpayer seeking the credit; the name, address, and phone number of the person that converted the motor vehicle to run on a clean fuel; the VIN; the date of conversion; and the price of the conversion equipment installed on the motor vehicle;

(2) a copy of the current Utah vehicle registration in the name of the taxpayer seeking the credit; and

(3) a signed statement by the person who converted the motor vehicle certifying that the conversion does not tamper with, circumvent, or otherwise affect the vehicle's on-board diagnostic system, in accordance with 19-1-406(2).

R307-121-8. Proof of Purchase to Demonstrate Eligibility for Special Mobile Equipment Converted to Clean Fuels.

To demonstrate that a conversion of special mobile equipment to be fueled by clean fuel is eligible for the tax credit, proof of purchase shall be made, in accordance with 59-7-605(3)(b) or 59-10-1009(3)(b), by submitting the following documentation to the director:

(1) a description, including serial number, of the special mobile equipment for which credit is to be claimed; and

(2) an original or copy of the purchase order, customer invoice, or receipt that includes the name of the taxpayer seeking the credit, the serial number, the date of conversion, and the price of the conversion equipment installed on the special mobile equipment.

KEY: air pollution, alternative fuels, tax credits, motor vehicles
Date of Enactment or Last Substantive Amendment: September 3, 2015
Notice of Continuation: January 23, 2012
Authorizing, and Implemented or Interpreted Law: 19-2-104; 19-1-402; 59-7-605; 59-10-1009

FIVE-YEAR NOTICE OF REVIEW AND STATEMENT OF CONTINUATION

Rule Information

DAR file no: Date filed:

State Admin Rule Filing Key: 157691

Utah Admin. Code ref. (R no.): R307-121

Agency Information

1. Agency: ENVIRONMENTAL QUALITY - Air Quality

Room no.: Fourth Floor

Building:

Street address 1: 195 N 1950 W

Street address 2:

City, state, zip: SALT LAKE CITY UT 84116-3085

Mailing address 1: PO BOX 144820

Mailing address 2:

City, state, zip: SALT LAKE CITY UT 84114-4820

Contact person(s):

Name:	Phone:	Fax:	E-mail:	Remove:
Mat Carlile	801-536-4116	801-536-4136	mcarlile@utah.gov	

(Interested persons may inspect this filing at the above address or at DAR during business hours)

Rule Title

2. Title of rule or section (catchline):

General Requirements: Clean Air and Efficient Vehicle Tax Credit.

Rule Provisions

3. A concise explanation of the particular statutory provisions under which the rule is enacted and how these provisions authorize or require the rule:

Sections 59-7-605 and 59-10-1009 authorize an income tax credit for those purchasing a new vehicle that uses natural gas, propane, or electricity. Rule R307-121 sets forth conditions for eligibility and the process of application for corporate and individual income tax credits, as required under Utah Code Section 19-2-104(3)(b)(vi).

Content Summary

4. A summary of written comments received during and since the last five-year review of the rule from interested persons supporting or opposing the rule:

Rule R307-121 has been amended five times since the last five-year review, DAR No. 35718 (nonsubstantive change), DAR No. 36809 (nonsubstantive change), DAR No. 37990 (Effective 1/1/2014), DAR No. 38837 (Effective 1/1/2015), and DAR No. 39353 (Effective 9/3/2015). One comment was received in relation to changes made to DAR No. 38837. The comment was about concerns that the proposed rule did not require any evidence that the system meets state emission requirements or is safe according to NFPA 52 code. Instead it puts the responsibility on the taxpayer to know those requirements and to certify that the installation complies with them. DAQ Response: The person commenting is correct when stating that the responsibility to ensure that the system meets emission and safety requirements falls on the taxpayer. Utah Code 19-2-406(1) states that the owner of the converted vehicle is responsible to ensure that the vehicle is inspected by a CSA America Inspector and tested to ensure that the vehicle satisfies emission standards. No other comments have been received since the last five-year review.

Justification Information

5. A reasoned justification for continuation of the rule, including reasons why the agency disagrees with comments in opposition to the rule, if any:

Rule R307-121 should be continued because it provides necessary guidance in the administration of the Utah Clean Fuel Tax Credit program, which is required by Utah Code Section 19-2-104(3)(b)(vi).

Indexing Information

6. Indexing information - keywords (maximum of four, one term per field, in lower case, except for acronyms (e.g., "GRAMA") or proper nouns (e.g., "Medicaid")):

air pollution, alternative fuels, tax credits, motor vehicles

File Information

7. Attach an RTF document containing the text of this rule change (filename):

There is a document associated with this rule filing.

To the Agency

Information requested on this form is required by Section 63G-3-305. Incomplete forms will be returned to the agency for completion, possibly delaying the effective date.

Agency Authorization

Agency head or designee, and title: Bryce Bird
Director

Date (mm/dd/yyyy): 08/23/2016

ITEM 6

State of Utah

GARY R. HERBERT
Governor

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Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-042-16

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Mat Carlile, Environmental Planning Consultant

DATE: August 22, 2016

SUBJECT: FINAL ADOPTION: New Rule R307-124. General Requirements: Conversion To Alternative Fuel Grant Program.

On June 1, 2016, the Air Quality Board proposed for public comment new rule, R307-124. This rule specifies the requirements and procedures for the Alternative Fuel Grant Program that was passed by the Utah Legislature during the 2015 General Legislative Session and funded during the 2016 General Legislative Session.

A public comment period was held from July 1 to August 1, 2016. No comments were received and a hearing was not requested.

Staff Recommendation: Staff recommends that the Board adopt R307-124 as proposed.

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R307. Environmental Quality, Air Quality.
R307-124. General Requirements: Conversion To Alternative Fuel Grant Program.
R307-124-1. Authorization and Purpose.

(1) This rule is authorized by Section 19-2-304, which establishes the requirements, procedures, criteria, and definitions used to determine eligibility for the Conversion to Alternative Fuel Grant Program.

(2) The procedures of this rule constitute the minimum requirements for the application and the awarding of funds that are designated for the Conversion to Alternative Fuel Grant Program.

R307-124-2. Definitions.

The following additional definitions apply to R307-124:

"Alternative fuel" means alternative fuel as defined in Subsection 19-2-302(2).

"Clean fuel grant" means clean fuel grant as defined in Subsection 19-2-302(4).

"Conversion equipment" means conversion equipment as defined in Subsection 19-2-302(5).

"Cost" means cost as defined in 19-2-302(6).

"Division" means the Division of Air Quality.

"Eligible vehicle" means eligible vehicle as defined in Subsection 19-2-302(9).

R307-124-3. Minimum Qualifications for an Applicant to Receive a Clean Fuel Grant.

(1) All applicants must be a registered business within the State of Utah and have a business license from the city or county in which they are located.

(2) Applicants that are applying for a clean fuel grant for a conversion of an eligible vehicle to run on propane must meet the requirements of R710-6 Liquefied Petroleum Gas (LPG) Rules.

R307-124-4. Minimum Qualifications for a Person that Installs Conversion Equipment on an Eligible Vehicle.

The following are the minimum qualifications for a person that installs conversion equipment on an eligible vehicle:

(1) A person that installs conversion equipment on an eligible vehicle to run on natural gas shall be:

(a) a Canadian Standards Association (CSA) America Compressed Natural Gas (CNG) Fuel System Inspector; or

(b) an Automotive Service Excellence (ASE) F1-certified technician.

(2) A person that installs conversion equipment on an eligible vehicle to run on propane shall be certified under R710-6 LPG Rules.

(3) A person that installs conversion equipment on an eligible vehicle to run on electricity shall be an ASE-certified technician.

R307-124-5. Preliminary Approval Application Procedure.

To be considered for a clean fuel grant all applicants shall apply for preliminary approval on forms provided by the Division as required by Subsection 19-2-304(1)(e), and shall provide additional information as requested by the Division.

(1) All applicants shall:

(a) acknowledge that receiving preliminary approval does not guarantee reimbursement by the Division, and preliminarily approved projects shall meet all the eligibility requirements listed in R307-124 before receiving the clean fuel grant for an eligible vehicle;

(b) certify under penalty of perjury and subject to provisions of Utah Code Section 76-8-504 ("written false statement"), that all savings on the cost of conversion equipment in the amount of the clean fuel grant will be passed to the owner of the eligible vehicle, as required in Subsection 19-2-303(2)(b);

(c) certify that the applicant is currently a registered business within the State of Utah and has a current business license; and

(d) agree to the provisions found in Subsection 19-2-303(3).

(2) Applicants applying for a clean fuel grant for a conversion of an eligible vehicle to run on natural gas shall provide the installer’s ASE F-1 or CSA America certification number.

(3) Applicants that are applying for a clean fuel grant for a conversion of an eligible vehicle to run on propane shall provide the applicant’s dealer license number and the installer’s LPG certification number required by R710-6 LPG Rules.

(4)Applicants that are applying for a clean fuel grant for a conversion of an eligible vehicle to run on electricity shall provide the installer’s ASE certification number.

(5) Preliminary approval will encumber funds for up to 60 calendar days from the preliminary application’s approval.

R307-124-6. Final Approval Procedure and Payment Process.

Once an applicant has encumbered funds for a conversion, the applicant has up to 60 calendar days to obtain final approval from the Division. To obtain final approval, the applicant shall apply for final approval on forms provided by the Division, as required by Subsection 19-2-304(1)(e), and shall provide additional information as requested by the Division.

(1) To demonstrate that a conversion of a vehicle to be fueled by natural gas is eligible, an applicant shall submit the following documentation to the Director:

(a) A copy of the applicant’s business registration from the Utah Department of Commerce and current business license from the city or county in which they are located;

(b) a copy of the installer’s CSA America or ASE F-1 certification;

(c) an original or copy of the purchase order, customer invoice, or receipt that includes:

(i) the name, address, and phone number of the applicant;

(ii) the name of the installer;
(iii) the vehicle identification number (VIN);
(iv) the date of conversion; and
(v) the cost of the conversion (itemizing the equipment, labor, and the clean fuel grant);
(d)(i) a copy of the vehicle inspection report dated after the conversion, from an approved county I/M station, showing that the converted motor vehicle meets all county emissions requirements for all installed fuel systems if the motor vehicle is registered within a county with an I/M program; or
(ii) in all other areas of the state, a signed statement by the installer that includes the VIN, the installer’s ASE or CSA America certification number, and states that the eligible vehicle’s conversion is functional;
(e) a copy of the current Utah vehicle registration; and
(f) a signed statement by the installer certifying that the conversion does not tamper with, circumvent, or otherwise affect the vehicle’s on-board diagnostic system, in accordance with Utah Code 19-1-406(2).
(2) To demonstrate that a conversion of a vehicle to be fueled by propane is eligible, an applicant shall submit the following documentation to the director:
(a) A copy of the applicant’s business registration from the Utah Department of Commerce and current business license from the city or county in which they are located;
(b) a copy of the applicant’s current dealer license required under R710-6;
(c) a copy of the installer’s current certification under R710-6;
(d)(i) a copy of the vehicle inspection report, dated after the conversion, from an approved county I/M station, showing that the converted motor vehicle meets all county emissions requirements for all installed fuel systems, if the motor vehicle is registered within a county with an I/M program, or
(ii) in all other areas of the state, a signed statement by an ASE-certified technician that includes the VIN, the technician's ASE certification number, and states that the conversion is functional;
(e) Provide the EPA Certificate of Conformity, or equivalent documentation that is consistent with requirements outlined in 40 CFR Part 85 and 40 CFR Part 86, as published in Federal Register Volume 76 Page 19830 on April 8, 2011, or an executive order from the California Air Resources Board;
(f) an original or copy of the purchase order, customer invoice, or receipt that includes:
(i) the name, address, and phone number of the applicant;
(ii) the name of the installer;
(iii) the VIN;
(iv) the date of conversion; and
(v) the cost of the conversion (itemizing the equipment, labor, and the clean fuel grant); and
(g) a copy of the current Utah vehicle registration.

(3) To demonstrate that a conversion of a motor vehicle to be powered by electricity is eligible, an applicant shall submit the following documentation to the director:

(a) A copy of the applicant’s business registration from the Utah Department of Commerce and current business license from the city or county in which they are located;

(b) a copy of the current Utah vehicle registration;

(c) an original or copy of the purchase order, customer invoice, or receipt that includes:

(i) the name, address, and phone number of the applicant;

(ii) the name of the installer;

(iii) the VIN;

(iv) the date of conversion; and

(v) the cost of the conversion (itemizing the equipment, labor, and the clean fuel grant);

(d) If the converted eligible vehicle does not have any auxiliary sources of combustion emissions, then the applicant shall submit a signed statement by an ASE-certified technician that includes the VIN, the technician's ASE certification number, and states that the conversion is functional and that the converted motor vehicle does not have any auxiliary source of combustion emissions.

(e) If the converted eligible vehicle has an auxiliary source of combustion emissions, the applicant shall submit:

(i) a copy of the vehicle inspection report after the conversion, from an approved county I/M station, showing that the converted motor vehicle meets all county emissions requirements for all installed fuel systems, if the motor vehicle is registered within a county with an I/M program; or

(ii) in all other areas of the state, a signed statement by an ASE-certified technician that includes the VIN, the technician's ASE certification number, and states that the conversion is functional; and

(iii) provide the EPA Certificate of Conformity, or equivalent documentation that is consistent with requirements outlined in 40 CFR Part 85 and 40 CFR Part 86, as published in Federal Register Volume 76 Page 19830 on April 8, 2011, or an executive order from the California Air Resources Board.

(4) All applicants shall complete and submit an IRS form W-9 to the Division.

(5) Approved applications shall continue to comply with the provisions of this rule.

R307-124-7. Grant Program Limitations.

Grant applications shall not be approved if:

(1) Awarding a grant to an applicant would result in the Department's inability to fulfill its obligations under this program or this rule;

(2) The applicant does not meet the approval requirements of Section R307-124-5;

(3) The fund balance is zero; or

(4) Awarding a grant to an applicant would result in the fund

balance being less than zero.

R307-124-8. Review.

The Division reserves the right to request supplemental information it may deem necessary from an applicant, in order to effectively administer the program and this rule.

KEY: air pollution, alternative fuels, tax credits, motor vehicles
Date of Enactment or Last Substantive Amendment:
Notice of Continuation:
Authorizing, and Implemented or Interpreted Law: 19-2-301 through 305; 19-1-403.3

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-044-16

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Joel Karmazyn, Environmental Scientist

DATE: August 24, 2016

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend R307-302. Solid Fuel Burning Devices.

On February 25, 2016, the Environmental Protection Agency (EPA) approved all but two of the area source rules that were included as control measures in the $PM_{2.5}$ State Implementation Plan. R307-302, Solid Fuel Burning Devices in Box Elder, Cache, Davis, Salt Lake, Tooele, Utah, and Weber Counties, was one of those rules. The EPA informed staff that amendments to R307-302 were needed before it could be approved. The EPA suggested that R307-302 be amended to include continuous controls in the form of a list of prohibited burning materials. These controls would apply at all times, including during start-up and refueling.

On June 1, 2016, staff brought R307-302 to the Board with the changes the EPA had requested. Several Board members had suggestions on how to improve the rule before it was put out for public comment. Staff has considered those suggestions, and the rule has been amended to include the following changes:

- A definition for “seasoned wood” was added.
- The word “fireplace” was removed because it was redundant.
- R307-302-5(3) was amended to clarify that a person burning wood in a solid fuel burning device may only burn seasoned wood.
- The term “facilities” was removed because “facility” is defined in R307-101-2.
- “Phase 2” was removed from R307-302-6 to be consistent with the terminology used in the 2015 New Source Performance Standard.
- The option to register a solid fuel burning device with the local health district was removed because Utah Code 19-2-107.5 requires registration with the Division.

On August 18, 2016, the EPA published a conditional approval of R307-302 based on the Division's commitment to include a list of prohibited fuels in the rule. The EPA also stated that the rule would satisfy the Clean Air Act requirement to implement Reasonably Available Control Measures (RACM). If the Board promulgates R307-302 as amended, EPA has indicated that they can approve it, and it will become part of Utah's $PM_{2.5}$ State Implementation Plan.

Staff Recommendation: Staff recommends that the Board propose the amended R307-302 for public comment.

R307. Environmental Quality, Air Quality.
R307-302. Solid Fuel Burning Devices [~~in Box Elder, Cache, Davis, Salt Lake, Tooele, Utah, and Weber Counties~~].
R307-302-1. Purpose and Definitions.

(1) R307-302 establishes emission standards for [~~fireplaces and~~]all solid fuel burning devices [~~used in residential, commercial, institutional and industrial facilities and associated outbuildings~~] used to provide comfort heating.

(2) The following additional definitions apply to R307-302:

"Seasoned wood" means wood that has a moisture content of less than or equal to 25%.

"Sole source of heat" means the solid fuel burning device is the only available source of heat for the entire residence, except for small portable heaters.

"Solid fuel burning device" means fireplaces, wood stoves and boilers used for burning wood, coal, or any other nongaseous and non-liquid fuel, both indoors and outdoors, but excluding outdoor wood boilers, which are regulated under R307-208.

R307-302-2. Applicability.

(1) R307-302-3 and R307-302-6 shall apply to any solid fuel burning device used to provide comfort heating in PM10 [~~and~~]or PM2.5 nonattainment [~~and~~]or maintenance areas as defined in 40 CFR 81.345 (July 1, 2011). [~~and geographically described as all regions of Salt Lake and Davis counties; all portions of the Cache Valley; all regions in Weber and Utah counties west of the Wasatch mountain range;~~] Collectively, The PM10 and PM2.5 nonattainment and maintenance plan areas are geographically defined as all regions of Salt Lake and Davis counties; all portions of the Cache Valley; all regions in Weber County west of the Wasatch mountain range; all regions of Utah County; in Box Elder County, from the Wasatch mountain range west to the Promontory mountain range and south of Portage; and in Tooele County, from the northernmost part of the Oquirrh mountain range to the northern most part of the Stansbury mountain range and north of Route 199.

(2) R307-302-4 shall apply only within the city limits of Provo in Utah County.

(3) R307-302-5 shall apply in all portions of Box Elder, Cache, Davis, Salt Lake, Tooele, Utah and Weber counties.

(4) The following exemptions apply to R307-302:

(a) R307-302 does not apply to restaurant and institutional food preparation.

(b) R307-302 does not apply to commercial and industrial boilers subject to an approval order issued under R307-401.

(c) R307-302-3 does not apply to sources located above 7,000 feet in elevation within Box Elder, Davis, Salt Lake, Tooele, Utah and Weber counties.

(d) R307-302 does not apply to firefighting training devices that meet the definition of a solid fuel burning device.

R307-302-3. No-Burn Periods for [~~Fine~~] Particulates.

(1) [~~By June 1, 2015,~~]A person using a solid fuel burning

device as a sole source[~~s~~] of [~~residential~~] heat[~~ing using solid fuel burning devices~~] must [~~be~~] register[~~ed~~] with the director in order to be exempt during mandatory no-burn periods.

(2) When the ambient concentration of PM10 measured by the monitors in Salt Lake, Davis, Weber, or Utah counties reaches the level of 120 micrograms per cubic meter and the forecasted weather for the specific area includes a temperature inversion which is predicted to continue for at least 24 hours, the director will issue a public announcement and will distribute such announcement to the local media notifying the public that a mandatory no-burn period for solid fuel burning devices [~~and fireplaces~~] is in effect. The mandatory no-burn periods will only apply to those areas or counties impacting the real-time monitoring site registering the 120 micrograms per cubic meter concentration. [~~Residents, commercial, institutional and industrial facilities of~~] A person in the affected areas shall not use a solid fuel burning device[~~s or fireplaces except those that are~~]unless it is the sole source of heat for [~~the~~]an entire residence and registered with the director.

(3) PM10 Contingency Plan. If the PM10 Contingency Plan described in Section IX, Part A, of the State Implementation Plan has been implemented, the trigger level for no-burn periods as specified in R307-302-3(2) will be 110 micrograms per cubic meter for that area where the PM10 Contingency Plan has been implemented.

(4) When the ambient concentration of PM2.5 measured by monitors in Box Elder, Cache, Davis, Salt Lake, Tooele, Utah or Weber counties are forecasted to reach or exceed 25 micrograms per cubic meter, the director will issue a public announcement to provide broad notification that a mandatory no-burn period for solid fuel burning devices [~~and fireplaces~~] is in effect. The mandatory no-burn periods will only apply to those counties identified by the director. [~~Residents, commercial, institutional and industrial facilities~~]A person within the geographical boundaries described in R307-302-2(1) shall not use a solid fuel burning device[~~s or fireplaces except those that are~~]unless it is the sole source of heat for [~~the~~]an entire residence and registered with the director.

(5) PM2.5 Contingency Plan. If the PM2.5 contingency plan of the State Implementation Plan has been implemented, the trigger level for no-burn periods as specified in R307-302-3(4) shall be 15 micrograms per cubic meter for the area where the PM2.5 contingency plan has been implemented.

R307-302-4. No-Burn Periods for Carbon Monoxide.

(1) Beginning on November 1 and through March 1, the director will issue a public announcement and will distribute such announcement to the local media notifying the public that a mandatory no-burn period for solid fuel burning devices [~~and fireplaces~~] is in effect when the running eight-hour average carbon monoxide concentration as monitored by the state at 4:00 PM reaches a value of 6.0 ppm or more.

(2) In addition to the conditions contained in R307-302-4(1), the director may use meteorological conditions to initiate a no-burn period. These conditions are:

(a) A national weather service forecasted clearing index value of 250 or less;

(b) Forecasted wind speeds of three miles per hour or less;

(c) Passage of a vigorous cold front through the Wasatch Front; or

(d) Arrival of a strong high pressure system into the area.

(3) During the no-burn periods specified in R307-302-4(1) and (2), [~~residents, commercial, institutional and industrial facilities~~]a person in Provo City shall not use a solid fuel burning device[~~s or fireplaces except those that are~~] unless it is the sole source of heat for [~~the~~]an entire residence and [~~are~~]is registered with the director [~~or the local health district office~~].

R307-302-5. Opacity and Prohibited Fuels for Heating Appliances.

(1) Except during no-burn periods as required by R307-302-3 and 4, visible emissions from solid fuel burning devices [~~and fireplaces~~] shall be limited to a shade or density no darker than 20% opacity as measured by EPA Method 9, except for the following:

([~~1~~]a) An initial fifteen minute start-up period, and

([~~2~~]b) A period of fifteen minutes in any three-hour period in which emissions may exceed the 20% opacity limitation for refueling.

(2) Prohibited Fuels: A person shall not cause or allow any of the following materials to be burned in a solid fuel burning device at any time:

(a) asphaltic products;

(b) books and magazines;

(c) garbage;

(d) paints;

(e) colored/wrapping paper;

(f) plastic;

(g) rubber products;

(h) treated wood;

(i) waste petroleum products; or

(j) any other material not intended by a manufacturer for use as a fuel in a solid fuel burning device.

(3) A person burning wood in a solid fuel burning device shall only burn seasoned wood.

R307-302-6. Prohibition.

(1) [~~Beginning September 1, 2013, n~~]No person shall sell, offer for sale, supply, install, or transfer a wood burning stove that is not EPA [~~Phase 2~~] certified or a fireplace that is not EPA qualified.

(2) Ownership of a non EPA [~~Phase 2~~] certified stove within a residential dwelling installed prior to March 6, 2014 may be transferred as part of a real estate transaction, so long as the

unit remains intact within the real property of sale.

KEY: air pollution, fireplaces, stoves, solid fuel burning
Date of Enactment or Last Substantive Amendment: [~~February 4, 2015~~]2016

Notice of Continuation: May 6, 2015
Authorizing, and Implemented or Interpreted Law: 19-2-101; 19-2-104

NOTICE OF
PROPOSED RULE AMENDMENT

- The agency identified below in box 1 provides notice of proposed rule change pursuant to Utah Code Section 63G-3-301.
- Please address questions regarding information on this notice to the agency.
- The full text of all rule filings is published in the Utah State Bulletin unless excluded because of space constraints.
- The full text of all rule filings may also be inspected at the Office of Administrative Rules.

Rule Information

DAR file no: Date filed:

State Admin Rule Filing Key: 157553

Utah Admin. Code ref. (R no.): R307-302-5

Agency Information

1. Agency: ENVIRONMENTAL QUALITY - Air Quality

Room no.: Fourth Floor

Building:

Street address 1: 195 N 1950 W

Street address 2:

City, state, zip: SALT LAKE CITY UT 84116-3085

Mailing address 1: PO BOX 144820

Mailing address 2:

City, state, zip: SALT LAKE CITY UT 84114-4820

Contact person(s):

Name:	Phone:	Fax:	E-mail:	Remove:
Ryan Stephens	801-536-4419	801-536-0085	rstephens@utah.gov	

(Interested persons may inspect this filing at the above address or at DAR during business hours)

Rule Title

2. Title of rule or section (catchline):
Opacity for Heating Appliances.

Notice Type

3. Type of notice: Amendment

Rule Purpose

4. Purpose of the rule or reason for the change:

   This rule change is being proposed for the purpose of developing an EPA approvable PM2.5 State Implementation Plan. The amendment is being proposed in response to a request from the EPA that the rule should provide controls during start-up and refueling processes.

Response Information

5. This change is a response to comments by the Administrative Rules Review Committee.

   ◉ No ○ Yes

Rule Summary

6. Summary of the rule or change:

   The rule has been amended to include the following changes: 1) A definition for “seasoned wood” was added; 2)The word “fireplace” was removed because it was redundant; 3) R307-302-5(3) was amended to clarify that a person burning wood in a solid fuel burning device may only burn seasoned wood; 4) The term “facilities” was removed because “facility” is defined in R307-101-2; 5) “Phase 2” was removed from R307-302-6 to be consistent with the terminology used in the 2015 New Source Performance Standard; 6) The option to register a solid fuel burning device with the local health district was removed because Utah Code 19-2-107.5 requires registration with the Division; and 7) A list of continuous controls in the form of prohibited burning materials was added.

Aggregate Cost Information

7. Aggregate anticipated cost or savings to:

   A) State budget:

   Affected: ○ No ◉ Yes

   There will be minimal impact on the state budget. If the state owns a regulated heating appliance as described in the rule, then the state may have a small cost associated with switching to non-prohibited materials.

   B) Local government:

   Affected: ○ No ◉ Yes

   There will be minimal impact on local governments. If a government owns a regulated heating appliance as described in the rule, then the government may have a small cost associated with switching to non-prohibited materials.

   C) Small businesses:

   Affected: ○ No ◉ Yes

   ("small business" means a business employing fewer than 50 persons)

   There will be minimal impact on small businesses. If a small business owns a regulated heating appliance as described in the rule, then the small business may have a cost associated with switching to non-prohibited materials.

   D) Persons other than small businesses, businesses, or local government entities:

   Affected: ○ No ◉ Yes

   ("person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an agency)

   Persons other than small businesses, businesses, or local government entities will be impacted in a small way. "Other persons" will not be able to burn materials on the prohibited burn list in regulated devices. They will have to purchase an approved solid fuel as described in the rule in order to use their device.

Compliance Cost Information

8. Compliance costs for affected persons:

   People who use solid fuel burning devices will have to take on the cost of switching fuels, if their fuel is on the prohibited list.

Department Head Comments

9. A) Comments by the department head on the fiscal impact the rule may have on businesses:

   This rule amendment will have a minimal fiscal impact on businesses. Some businesses may be impacted by the rule if they are burning prohibited items in a solid fuel burning device used for comfort heating. The fiscal impact to these businesses will be the cost of switching to an approved fuel.

   B) Name and title of department head commenting on the fiscal impacts:

Citation Information

10. This rule change is authorized or mandated by state law, and implements or interprets the following state and federal laws.
State code or constitution citations (required) (e.g., Section 63G-3-402; Subsection 63G-3-601(3); Article IV) :
19-2-104

Incorporated Materials

11. This rule adds, updates, or removes the following title of materials incorporated by reference (a copy of materials incorporated by reference must be submitted to DAR; if none, leave blank) :

Official Title of Materials Incorporated (from title page)
Publisher
Date Issued (mm/dd/yyyy)
Issue, or version (including partial dates)
ISBN Number
ISSN Number
Cost of Incorporated Reference
Adds, updates, removes-- SELECT ONE --

Comments

12. The public may submit written or oral comments to the agency identified in box 1. (The public may also request a hearing by submitting a written request to the agency. The agency is required to hold a hearing if it receives requests from ten interested persons or from an association having not fewer than ten members. Additionally, the request must be received by the agency not more than 15 days after the publication of this rule in the Utah State Bulletin. See Section 63G-3-302 and Rule R15-1 for more information.)
A) Comments will be accepted until 5:00 p.m. on (mm/dd/yyyy) : 10/31/2016
B) A public hearing (optional) will be held:
On (mm/dd/yyyy): At (hh:mm AM/PM): At (place):

Proposed Effective Date

13. This rule change may become effective on (mm/dd/yyyy): 11/07/2016

NOTE: The date above is the date on which this rule MAY become effective. It is NOT the effective date. After a minimum of seven days following the date designated in Box 12(A) above, the agency must submit a Notice of Effective Date to the Office of Administrative Rules to make this rule effective. Failure to submit a Notice of Effective Date will result in this rule lapsing and will require the agency to start the rulemaking process over.

Indexing Information

14. Indexing information - keywords (maximum of four, one term per field, in lower case, except for acronyms (e.g., "GRAMA") or proper nouns (e.g., "Medicaid")):

air pollution, fireplaces, solid fuel burning, stoves

File Information

15. Attach an RTF document containing the text of this rule change (filename):

No document is associated with this filing.

To the Agency

Information requested on this form is required by Sections 63G-3-301, 302, 303, and 402. Incomplete forms will be returned to the agency for completion, possibly delaying publication in the Utah State Bulletin, and delaying the first possible effective date.

Agency Authorization

Agency head or designee, and title: -- SELECT ONE -- Date (mm/dd/yyyy): 08/24/2016

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-046-16

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Bill Reiss, Environmental Engineer

DATE: August 25, 2016

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend SIP Subsection IX. Part H: Emission Limits and Operating Practices. Specifically Proposed for Amendment are the PM2.5 Requirements in Subparts H. 11, 12, and 13, and the PM10 Requirements in Subpart H.2.

On December 3, 2014, the Board adopted the State Implementation Plan (SIP) Subsection IX. Part H. subparts 11, 12, and 13: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, $PM_{2.5}$ Requirements. The terms in these subparts enforce the plan requirements for stationary sources located in the Salt Lake City and Provo $PM_{2.5}$ nonattainment areas. Part H was submitted to EPA as part of the Moderate Area $PM_{2.5}$ SIP for each area.

Part H also includes, in subparts 1–4, emission limits and operating practices specific to PM_{10}. The Board revised these subparts, in support of PM_{10} Maintenance Plans for the Salt Lake County and Utah County nonattainment areas, on December 2, 2015. These PM_{10} emission limits and operating practices were written to be as consistent as possible with the $PM_{2.5}$ limits and practices in subparts 11–13. As such, the revisions to the PM_{10} limits also addressed comments made by the EPA in its review of the draft 2014 $PM_{2.5}$ SIP.

Some of those comments could not be addressed at the time the SIP was finalized, so in essence, the PM_{10} conditions had "leap-frogged" the corresponding $PM_{2.5}$ conditions.

Most of the amendments proposed herein are intended as a final "clean-up" of the $PM_{2.5}$ conditions. The amendments will make the $PM_{2.5}$ conditions in Part H consistent with the corresponding PM_{10} conditions. This clean-up will address all of EPA's comments. Most importantly, this effort is intended to facilitate EPA's review and ultimate approval of the Moderate Area $PM_{2.5}$ SIPs for the Salt Lake City and Provo nonattainment areas, as well as the PM_{10} Maintenance Plans. Part H is central to both SIPs.

The proposed $PM_{2.5}$ revisions can be generalized to cover the following objectives:

Source Monitoring: To require the use of Continuous Emission Monitoring Systems (CEMS) wherever feasible, assign stack testing frequencies at no less than once every 3 years, and employ where practicable the use of interim, parametric monitoring (between stack tests).

Emission Limits: To match the emission limits with the 24-hour averaging period of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS), include condensable $PM_{2.5}$ in the limits where appropriate, and generally ensure federal enforceability.

In addition to the objectives summarized above, the proposed $PM_{2.5}$ amendments include:

- Corrections to emission limits at Chemical Lime Company (H.12.e) based on updated emission factors.

- Revision to the compliance schedule for Compass Minerals (formerly Great Salt Lake Minerals, at H.12.g).

- Elimination of the conditions for Hill Air Force Base (H.12.i). RACT will instead be insured through compliance with R307-355, Control of Emissions from Aerospace Manufacture and Rework Facilities.

- Clarification of the terms affecting units 1, 2, and 3 at Kennecott's Utah Power Plant (H.12.k).

- Elimination of the conditions for Vulcraft/Nucor Building Systems (H.12.u). RACT will instead be insured through compliance with R307-350, Miscellaneous Metal Parts and Products Coatings.

Finally, existing language at Part H.11.g.vii, which was intended to facilitate the production of gasoline meeting the sulfur specification of Tier 3, cannot be approved by EPA. The proposed revision eliminates this language.

The only proposed revision to Part H affecting PM_{10} re-introduces a requirement for Kennecott to operate its existing wet scrubber at the Copperton Concentrator (H.2.g.2). This revision will not affect emissions. Rather, it addresses a potential backsliding issue that would have hampered Region 8's approval of the PM_{10} Maintenance Plan.

Staff Recommendation: Staff recommends that the Board propose for public comment SIP Subsection IX. Part H: Emission Limits and Operating Practices, as amended in subparts 2, 11, 12, and 13.

H.2 Source Specific Emission Limitations in Salt Lake County PM_{10} Nonattainment/Maintenance Area

g. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

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

KUC shall keep records of daily total mileage for all periods when the mine is in operation. KUC shall track haul truck miles with a Global Positioning System or equivalent. The system shall use real time tracking to determine daily mileage.

B. To minimize fugitive dust on roads at the mine, the owner/operator shall perform the following measures:

I. Apply water to all active haul roads as weather and operational conditions warrant except during precipitation or freezing weather conditions, and shall apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.

II. Chemical dust suppressant shall be applied as weather and operational conditions warrant except during precipitation or freezing weather conditions on unpaved access roads that receive haul truck traffic and light vehicle traffic.

III. Records of water and/or chemical dust control treatment shall be kept for all periods when the BCM is in operation.

IV. KUC is subject to the requirements in the most recent federally approved Fugitive Emissions and Fugitive Dust rules.

C. To minimize emissions at the mine, the owner/operator shall:

I. Control emissions from the in-pit crusher with a baghouse.

D. Implementation Schedule

KUC shall purchase new haul trucks with the highest engine Tier level available which meet mining needs. KUC shall maintain records of haul trucks purchased and retired

ii. Copperton Concentrator (CC)

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

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

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

i. ~~Bingham Canyon Mine (BCM)~~

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

~~KUC shall keep records of daily total mileage for all periods when the mine is in operation. KUC shall track haul truck miles with a Global Positioning System or equivalent. The system shall use real time tracking to determine daily mileage.~~

B. ~~KUC shall use ultra-low sulfur diesel fuel in its haul trucks.~~

C. ~~To minimize emissions at the mine, the owner/operator shall:~~

I. ~~Control emissions from the in-pit crusher with a baghouse.~~

II. ~~Use ore conveyors as the primary means for transport of crushed ore from the mine to the concentrator.~~

D. ~~To minimize fugitive dust on roads at the mine, the owner/operator shall perform the following measures:~~

I. ~~Apply water to all active haul roads as weather and operational conditions warrant except during precipitation or freezing weather conditions, and shall apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.~~

II. ~~Chemical dust suppressant shall be applied as weather and operational conditions warrant except during precipitation or freezing weather conditions on unpaved access roads that receive haul truck traffic and light vehicle traffic.~~

E. ~~KUC is subject to the requirements in the most recent federally approved Fugitive Emissions and Fugitive Dust rules.~~

H.11. General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM2.5 Requirements~~H.11. General Requirements~~

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 ~~two~~ 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 ~~during steady-state operation~~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 (either PM10 and/or PM2.5 listed in Subsections IX.H.12 and IX.H.13 include both filterable and condensable PM, unless otherwise specified in the source specific conditions listed in IX.H.12 and IX.H.13.

e. Stack Testing:
   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 "SO_2 Removal & PM, SO_2, 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, Method 5, 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.~~PM_{10}: 40 CFR 51, Appendix M, Methods 201, 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. For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5B, 5D,5E, 5F, or 5I as appropriate, or other EPA-approved testing methods acceptable to the Director. The back half condensables shall also be tested using EPA approved testing methods acceptable to the Director. The portion of the front half of the catch considered PM_{10} 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. PM2.5: 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 PM2.5 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.~~$PM_{2.5}$: For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, 201a and 202, or other EPA approved testing methods acceptable to the Director. All particulate captured shall be considered $PM_{2.5}$. The back half condensables shall be used for compliance demonstration as well as for inventory purposes. For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5B, 5D,5E, 5F, or 5I as appropriate, or other EPA-approved testing methods acceptable to the Director. The back half condensables shall also be tested EPA-approved testing methods acceptable to the Director. 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.~~

F. SO_2: 40 CFR 60 Appendix A, Method ~~6, 6A, 6B,~~ 6C, or other EPA-approved testing methods acceptable to the Director.

G. NO_x: 40 CFR 60 Appendix A, Method ~~7, 7A, 7B, 7C, 7D,~~ 7E, or other EPA-approved testing methods acceptable to the Director.

H. VOC: 40 CFR 60 Appendix A, Method 25A or other EPA-approved testing methods acceptable to the Director.~~VOC: EPA-approved testing methods acceptable to the Director.~~

I. 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.

J. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. ~~Notification of the test date shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location. The production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.~~

K. 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

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

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

A. FCCU SO_2 Emissions

I. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an SO_2 emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.

II. Compliance with this limit shall be determined by following 40 C.F.R. §60.105a(g).

B. FCCU PM Emissions

I. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds coke burned on a 3-hour average basis.

II. Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests once every five years at each FCCU.

III. By no later than January 1, 2019, each owner or operator of an FCCU shall install, operate and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters for determination of source-wide PM2.5 emissions as appropriate

ii. Limits on Refinery Fuel Gas

A. By no later than January 1, 2018, all petroleum refineries in or affecting the $PM_{2.5}$ nonattainment area shall reduce the H_2S content of the refinery plant gas to 60 ppm 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 monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CR 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.

B. For natural gas, compliance is assumed while the fuel comes from a public utility.

iii. Limits on Heat Exchangers

A. Each owner or operator shall comply with the requirements of 40 CFR 63.654 for heat exchange systems in VOC service as soon as practicable but no later than January 1, 20158. The owner or operator may elect to use another EPA-approved method other than the Modified El Paso Method if approved by the Director.

I. The following applies in lieu of 40 CFR 63.654(b): A heat exchange system is exempt from the requirements in paragraphs 63.654(c) through (g) of this section if it meets any one of the criteria in the following paragraphs (1) through (2) of this section.

1. All heat exchangers that are in VOC service within the heat exchange system that either:

a. Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or

b. Employ an intervening cooling fluid, containing less than 10 percent by weight of VOCs, between the process and the cooling water. This intervening fluid must serve to isolate the cooling water from the process fluid and must not be sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes.

2. The heat exchange system cools process fluids that contain less than 10 percent by weight VOCs (i.e., the heat exchange system does not contain any heat exchangers that are in VOC service).

iv. Leak Detection and Repair Requirements

A. Each owner or operator shall comply with the requirements of 40 CFR 60.590a to 60.593a as soon as practicable but no later than January 1, ~~2018~~2016.

B. For units complying with the Sustainable Skip Period, previous process unit monitoring results may be used to determine the initial skip period interval provided that each valve has been monitored using the 500 ppm leak definition.

v. Requirements on Hydrocarbon Flares

A. Beginning January 1, 2018, all hydrocarbon flares at petroleum refineries located in or affecting a designated $PM_{2.5}$ non-attainment area within the State shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a–109a), if not already subject under the flare applicability provisions of Ja.

B. By no later than January 1, 2019, all major source petroleum refineries in or affecting a designated PM2.5 non-attainment area within the State shall either 1) install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c), or 2) limit flaring during normal operations to 500,000 scfd for each affected flare. Flare gas recovery is not required for dedicated SRU flare and header systems, or HF flare and header systems.

vi. Requirements on Tank Degassing

A. Beginning January 1, 2017, the owner or operator of any stationary tank of 40,000-gallon or greater capacity and containing or last containing any organic liquid, with a true vapor pressure equal or greater than 10.5 kPa (1.52 psia) at storage temperature (see R307-324-4(1)) shall not allow it to be opened to the atmosphere unless the emissions are controlled by exhausting VOCs contained in the tank vapor-space to a vapor control device until the organic vapor concentration is 10 percent or less of the lower explosion limit (LEL).

B. These degassing provisions shall not apply while connecting or disconnecting degassing equipment.

C. The Director shall be notified of the intent to degas any tank subject to the rule. Except in an emergency situation, initial notification shall be submitted at least three (3) days prior to degassing operations. The initial notification shall include:

I. Start date and time;

II. Tank owner, address, tank location, and applicable tank permit numbers;

III. Degassing operator's name, contact person, telephone number;

IV. Tank capacity, volume of space to be degassed, and materials stored;

V. Description of vapor control device.

vii. No Burning of Liquid Fuel Oil in Stationary Sources

A. No petroleum refineries in or affecting any PM nonattainment or maintenance area shall be allowed to burn liquid fuel oil in stationary sources except during natural gas curtailments or as specified in the individual subsections of Section IX, Part H.

B. The use of diesel fuel meeting the specifications of 40 CFR 80.510 in standby or emergency equipment is exempt from the limitation of IX.H.11.g.vii.A above.

viii. ~~The requirements set forth in Parts IX.H.11 and IX.H.12 shall apply unless and until the following occur:~~

A. ~~A Notice of Intent is submitted to the Director, pursuant to the procedures of R307-401, that describes the specific technologies that will be used to produce gasoline that meets the corporate average sulfur specification for Tier 3 of the federal motor vehicle control program, as specified in 40 CFR 80.~~

B. ~~An Approval Order is issued that authorizes implementation of the approach set forth in the Notice of Intent. *(editorial note: The intent of this language was to prevent the SIP limits from becoming an impediment to the production of Tier 3 fuel in the event that an Approval Order could otherwise be issued in accordance with R307-401. Underlying that*~~

~~*purpose is the assumption that, because the offsetting requirement for a would-be major modification in this nonattainment area can no longer be met until such time as sufficient emission reduction credits can be created (post- Dec. 4, 2013), only minor modifications could be permitted. Net emission increases in such a permit could only reach levels defined as "significant" for such purposes. These levels of significance are 15 tons per year (tpy) for PM10, 10 tpy for PM2.5, 40 tpy for SO2 or NOx, and 40 tpy for VOC in the enveloped ozone maintenance area. In the context of a modeled SIP demonstration, it would ordinarily be necessary to incorporate such increases in emissions, at their maximum levels and at every refinery, in the modeled demonstration. However, since this plan revision demonstrates instead that it is impracticable to attain the 2006 24-hour NAAQS for PM2.5 (in accordance with CAA Section 189(a)(1)(B(ii)), the additional emissions would, if modeled, only serve to underscore the conclusion that attainment of this standard, by the applicable attainment date, is in fact impracticable. For this reason, it is unnecessary to re-specify herein each limit so as to also include the additional (significant) emissions.)*~~

C. ~~Notwithstanding the requirements specified in R307-401, the Notice of Intent must demonstrate that the technologies specified in the Approval Order would represent Reasonably Available Control Measures (RACM), as required by Section 172(c)(1) of the Clean Air Act.~~

D. ~~To the extent that the current SIP requirements outlined in Parts IX.H.11 and IX.H.12 have been relied upon by the Utah SIP to satisfy Section 172(c) or Section 189(a)(1) of the Clean Air Act, demonstrate that the technologies specified in the Approval Order would also be consistent with the achievement of reasonable further progress and would not interfere with attainment or maintenance of the National Ambient Air Quality Standards for particulate matter. The demonstration required in this paragraph may incorporate modeling previously conducted by the State for the purposes of Sections172(c)(1) or 189(a)(1)(B) of the Clean Air Act.~~

E. ~~The technologies specified in the Approval Order have been installed and tested in accordance with the Approval Order.~~

F. ~~As of the effective date of the Approval Order the affected PM2.5, SO2, VOC and NOx emissions limits, including applicable monitoring requirements, set forth in that permit as most recently amended, shall become incorporated by reference into the Utah SIP. Henceforth, those terms and conditions specified and identified in the Approval Order28 shall supersede the affected conditions in Parts IX.H.11 and IX.H.12.~~

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 PM2.5 levels exceed 35 ug/m3at the nearest real-time monitoring station, the open burning of reactive wastes with properties identified in 40 CFR 261.23 (a) (6) (7) (8) will be limited to 50 percent of the treatment facility's Department of Solid and Hazardous Waste permitted daily limit. During this period, on days when open burning occurs, records will be maintained identifying the quantity burned and the PM2.5 level at the nearest real-time monitoring station.

ii. During the period November 1 to February 28/29, on days when the 24-hour average PM2.5 levels exceed 35 ug/m3 at the nearest real-time monitoring station, the following shall not be tested:

A. Propellant, energetics, pyrotechnics, flares and other reactive compounds greater than 2,400 lbs. per day; or

B. Rocket motors less than 1,000,000 lbs. of propellant per motor subject to the following exception:

I. A single test of rocket motors less than 1,000,000 lbs. of propellant per motor is allowed on a day when the 24-hour average PM2.5 level exceeds 35 ug/m3 at the nearest real-time monitoring station provided notice is given to the Director of the Utah Air Quality Division. No additional tests of rocket motors less than 1,000,000 lbs. of propellant may be conducted during the inversion period until the 24-hour average PM2.5 level has returned to a concentration below 35 ug/m3 at the nearest real-time monitoring station.

C. During this period, records will be maintained identifying the size of the rocket motors tested and the 24-hour average PM2.5 level at the nearest real-time monitoring station on days when motor testing occur.

iii. Natural Gas-Fired Boilers

A. Building M-576

~~I. Startup and shutdown events shall not exceed 124 hours per boiler per 12-month rolling period.~~

~~I~~I. One 71 MMBTU/hr boiler shall be upgraded with low NOx 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 NOx emission rate is no greater than 30 ppm.

~~I~~II. ~~Emissions will be controlled during startup and shutdown operations by following manufacture procedures based on best management practices.~~ Records shall be kept on site which indicate the date, and time of startup and shutdown.

b. Big West Oil Refinery

i. Source-wide $PM_{2.5}$:

Following installation of the Flue Gas Blow Back Filter (FGF), but no later than January 1, 2019, combined emissions of PM2.5 (filterable+condensable) shall not exceed 0.29 tons per day and 72.5 tons per rolling 12-month period. By no later than January 1, 2019, Big West Oil shall conduct stack testing to establish the ratio of condensable PM2.5 from the Catalyst Regeneration System.~~Following installation of the Flue Gas Blow Back Filter (FGF), but no later than January 1, 2019, combined emissions of filterable $PM_{2.5}$ shall not exceed 0.18 tons per day and 45 tons per rolling 12-month period. By no later than January 1, 2019, Big West Oil shall conduct stack testing to establish the ratio of condensable PM2.5 from the Catalyst Regeneration System.~~

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.b.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM2.5: 1.9 lb/MMscf
Condensable PM2.5: 5.7 lb/MMscf

Plant gas:
Filterable PM2.5: 1.9 lb/MMscf
Condensable PM2.5: 5.7 lb/MMscf

Fuel Oil: The PM2.5 emission factors shall be determined from the latest edition of AP-42

FCC Stacks: The PM2.5 emission factors 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 for the FCC listed in IX.H.12.b.i.A above apply until such time as stack testing is conducted as outlined below:

PM2.5 stack testing on the FCC shall be performed initially no later than January 1, 2019 and at least once every three (3) years thereafter. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide PM2.5 Cap shall be determined for each day as follows:

Total 24-hour PM2.5 emissions for the emission points shall be calculated by adding the daily results of the PM2.5 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 PM2.5 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 gas consumption shall be measured by meters that can delineate the flow of gas to the boilers, furnaces and the SRU incinerator.

The equation used to determine emissions from these units shall be as follows:

Emissions = Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The daily PM2.5 emissions from the FCC shall be calculated using the following equation:

E = FR * EF

Where:
E = Emitted PM2.5
FR = Feed Rate to Unit (kbbls/day)
EF = emission factor (lbs/kbbl), established by the most recent stack test

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.

~~PM2.5 emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:~~

~~Natural gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)~~
~~Plant gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)~~

~~Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points.~~

~~The equations 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)~~
~~The daily filterable PM2.5 emissions from the Catalyst Regeneration System shall be calculated using the following equation:~~

~~E = FR * EF~~

~~Where:~~
~~E = Emitted PM2.5~~
~~FR = Feed Rate to Unit (kbbls/day)~~
~~EF = emission factor (lbs/kbbl), established by most recent stack test~~

~~Total 24-hour filterable PM2.5 emissions shall be calculated by adding the results of the above filterable PM2.5 equations for natural gas and plant gas combustion to the estimate for the Catalyst Regeneration System. Results shall be tabulated every 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
By no later than January 1, 2019, combined emissions of NOx shall not exceed 0.80 tons per day (tpd) and 195 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.b.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
Diesel fuel: shall be determined from the latest edition of AP-42

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 for the FCC listed in IX.H.12.b.ii.A above apply until such time as stack testing is conducted as outlined below:

Initial NOx stack testing on natural gas/refinery fuel gas combustion equipment above 40 MMBtu/hr has been performed and the next stack test shall be performed within 3 years of the previous stack test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.12.b.ii.A above. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide NOx Cap shall be determined for each day as follows:

Total 24-hour NOx 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:

NOx = Emission Factor (lb/MMscf)*Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)

Where the emission factor is derived from the fuel used, as listed in IX.H.12.b.ii.A above

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The daily NOx emissions from the FCC shall be calculated using a CEM as outlined in IX.H.11.f

Total daily NOx emissions shall be calculated by adding the results of the above NOx 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.

~~NOx emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:~~

~~Natural gas – latest version of AP-42 (currently see AP-42, Table 1.4-1)~~
~~Plant gas – assumed equal to natural gas (use values from AP-42, Table 1.4-1)~~

~~Since the emission factors are considered to be the same for either gas, this factor shall be applied to the metered quantity of blended gas. Should future information reveal that there is a difference in the emission factors for natural gas and plant gas, then the respective quantities shall be delineated in the AO.~~

~~Daily plant gas consumption at the furnaces and boilers shall be measured by flow meters. The equations 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)~~

~~The daily NOx emissions from the Catalyst Regeneration System shall be calculated using the following equation:~~

~~NOx = (Flue Gas, moles/hr) x (ADV ppm /10^6) x (30.006 lb/mole) x (operating hr/day)/(2000 lb/ton)~~

~~Where ADV = average daily value from NOx CEM~~

~~Total daily NOx emissions shall be calculated by adding the results of the above NOx equations for natural gas and plant gas combustion to the estimate for the Catalyst Regeneration System. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.~~

iii. Source-wide SO_2 Cap
By no later than January 1, 2019, combined emissions of shall not exceed 0.60 tons per day and 140 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 - 0.60 lb SO2/MMscf gas

Plant Gas: The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of 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.

Fuel oil: The emission factor to be used for combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA approved equivalent acceptable to the Director, and the density of the fuel oil, as follows:

EF (lb SO2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt. % S/100 * (64 lb SO2/32 lb S)

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

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 the daily SO2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

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 readings (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

~~SO2 emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:~~

~~Natural Gas - 0.60 lb SO2/MMscf gas~~

~~Plant Gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a continuous emissions monitor, which shall measure the H2S content of the fuel gas in ppmv. Daily emission factors shall be calculated using average daily H2S content data from the CEM. The emission factor shall be calculated as follows:~~

~~Emission Factor (lb SO2/MMscf gas) = [(24 hr avg. ppmv H2S)/10^6]*(64 lb SO2/lb mole)*[(10^6 scf/MMscf)/(379 scf/lb mole)]~~

~~Daily natural gas consumption shall be measured by the two meters that supply the refinery.~~

~~Daily plant gas consumption at the furnaces and boilers shall be measured by flow meters.~~

~~The equations used to determine emissions for the boilers and furnaces shall be as follows:~~

~~Emission Factor (lb/MMscf)*Natural Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)~~

~~Emission Factor (lb/MMscf)*Plant Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)~~

~~The daily SO2 emission from the Catalyst Regeneration System shall be calculated using the following equation:~~

~~SO2 = FG * (ADV/1,000,000) * (64 lb/mole) * (operating hours/day) / (2000 lb/ton)~~

~~Where:~~
~~FG = Flue Gas in moles/hour~~

~~ADV = average daily value from SO2 CEM~~

~~Total daily SO2 emissions shall be calculated by adding the daily results of the above SO2 emissions equations for natural gas and plant gas combustion to the estimate for the Catalyst Regeneration System. Results shall be tabulated every day, and records shall be kept which include the CEM readings for H2S (averaged for each day), all meter readings (in the appropriate units), 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.

c. Bountiful City Light and Power: Power Plant

i. Emissions to the atmosphere shall not exceed the following rates and concentrations:

A. GT #1 (5.3 MW Turbine) Exhaust Stack:
NO_x 0.6 g/kW-hr

B. GT #2 and GT #3 (each TITAN Turbine) Exhaust Stack:
NO_x 15 ppm

ii. Compliance to the above emission limitations shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP. ~~Each turbine shall be tested at least once per year.~~

A. Initial stack tests have been performed. Each turbine shall be tested at least once per year.

iii. Combustion Turbine Startup / Shutdown Emission Minimization Plan

A. Startup begins when natural gas is supplied to the combustion turbine(s) with the intent of combusting the fuel to generate electricity. Startup conditions end within sixty (60) minutes of natural gas being supplied to the turbine(s).

B. Shutdown begins with the initiation of the stop sequence of a turbine until the cessation of natural gas flow to the turbine.

C. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.

d. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

i. NOx emissions from the operation of all engines at the plant shall not exceed 0.648 tons per day.

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

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

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

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

C. NOx emissions shall be calculated on a daily basis.

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

E. The number of kilowatt hours generated by each engine shall be determined by examination of electrical meters, which shall record electricity production on a continuous basis.

~~NOx emissions from the operation of all engines at the plant shall not exceed 0.648 tons per day.~~

~~Compliance with the daily mass emission limits shall be demonstrated by multiplying emission factors (in units of mass per kw-hr) determined for each engine by the most recent stack test results, by the respective kilowatt hours generated each day. Power production shall be determined by examination of electrical meters which shall record the electricity production. Continuous recording is required. The records shall be kept on a daily basis.~~

~~NOx emission from the operation of all engines at the plant shall not exceed 205.6 tons per calendar year.~~

~~Stack testing to determine the emission factors necessary to show compliance with the emission limitations stated in this condition shall be performed at least once every five (5) years.~~

~~ii. Emissions to the atmosphere from each of the 1150 kw engine generators shall not exceed the following rates and concentrations:~~

~~Pollutant lb/hr gm/(hp-hr)~~

~~NOx 5.95 1.75~~

~~iii. Emissions to the atmosphere from each of the 1340 kw engine generators shall not exceed the following rates and concentrations:~~

~~Pollutant lb/hr gm/(hp-hr)~~

~~NOx 7.13 1.8~~

~~i. Compliance to the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP.~~

~~vii. Emissions will be controlled during startup and shutdown operations by following the manufacture procedures based on best management practices.~~

e. Chemical Lime Company (LHoist North America)

Lime Production Kiln

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

a. Effective January 1, 2019, NO_x emissions shall not exceed 56 lb/hr.

b. Compliance with the above emissions limit shall be determined by stack testing as outlined in Section IX Part H.11.e of this SIP.

ii. No later than January 1, 2019, or upon source start-up, whichever comes later, a baghouse control technology shall be installed and operating on the Lime Production Kiln for reduction of PM emissions.

a. Effective January 1, 2019, PM emissions shall not exceed 0.12 pounds per ton (lb/ton) of stone feed.

b. Effective January 1, 2019, $PM_{2.5}$ emissions shall not exceed 1.5 lbs/ton of stone feed.

c. Compliance with the above emission limits shall be determined by stack testing as outlined in Section IX Part H.11.e of this SIP and in accordance with 40 CFR 63 Subpart AAAAA.

iii. An initial compliance test is required no later than January 1, 2019 (if start-up occurs on or before January 1, 2019) or within 180 days of source start-up (if start-up occurs after January 1, 2019)

iv. Upon plant start-up kiln emissions shall be exhausted through the baghouse during all startup, shutdown, and operations of the kiln.

v. Start-up/shut-down provisions for SNCR technology be as follows:

a. No ammonia or urea injection during startup until the combustion gases exiting the kiln reach the temperature when NO_x reduction is effective, and

b. No ammonia or urea injection during shutdown.

c. Records of ammonia or urea injection shall be documented in an operations log. The operations log shall include all periods of start-up/shut-down and subsequent beginning and ending times of ammonia or urea injection which documents v.a and v.b above.

~~i. Lime Production Kiln:~~

~~A. Upon plant start-up SNCR technology shall be installed on the Lime Production Kiln for reduction of NOx emissions.~~

~~B. Upon plant start-up a baghouse control technology shall be installed and operating on the Lime Production Kiln for reduction of PM emissions.~~

~~I. PM emissions shall not exceed 0.12 pounds per ton (lb/ton) of stone feed~~

~~II. Compliance with the above emission limit shall be determined by stack testing as outlined in Section IX Part H.11.e of this SIP and in accordance with 40 CFR 63 Subpart AAAAA.~~

~~C. An initial compliance test is required within 180 days of source start-up.~~

~~D. Subsequent to initial compliance testing, stack testing is required at a minimum of every five years.~~

~~E. Startup/shutdown provisions for SNCR technology be as follows: (a) no ammonia or urea injection during startup until the combustion gases exiting the kiln reach the temperature when NOx reduction is effective, and (b) no ammonia or urea injection during shutdown.~~

f. Chevron Products Company - Salt Lake Refinery

i. Source-wide PM2.5 Cap

By no later than January 1, 2019, combined emissions of PM2.5 (filterable+condensable) shall not exceed 0.305 tons per day (tpd) and 110 tons per rolling 12-month period.~~By no later than January 1, 2019, combined emissions of filterable PM2.5 shall not exceed 0.18 tons per day (tpd) and 65 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.~~g~~f.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM2.5: 1.9 lb/MMscf
Condensable PM2.5: 5.7 lb/MMscf

Plant gas:
Filterable PM2.5: 1.9 lb/MMscf
Condensable PM2.5: 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)

Diesel fuel: shall be determined from the latest edition of AP-42

FCC Stack:
The PM2.5 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

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.12.~~g~~f.i.A above apply until such time as stack testing is conducted as outlined below:

Initial PM2.5 stack testing on the FCC stack has been performed and shall be conducted at least once every three (3) years from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide PM2.5 Cap shall be determined for each day as follows:

Total 24-hour PM2.5 emissions for the emission points shall be calculated by adding the

daily results of the PM2.5 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 PM2.5 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.

~~Compliance with the daily PM2.5 limit shall be determined daily by multiplying the quantity of each fuel burned at the affected units by the associated emission factor for that fuel, and summing the results.~~

~~PM2.5 emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:~~

~~Natural gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)~~
~~Plant gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)~~

~~Fuel Oil/ HF alkylation polymer: The filterable PM2.5 emission factor shall be determined based on the sulfur content of the fuel (S) according to the equation:~~

~~EF (lb/1000 gal) = (Wt. % S * 10) + 3.22~~

~~The condensable PM2.5 emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.~~

~~Daily plant gas consumption at the furnaces and boilers shall be measured by flow meters.~~

~~Daily fuel oil consumption shall be monitored with tank gauges. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.~~

~~The filterable PM2.5 emission factor for the FCC Catalyst Regenerator shall be determined based on the results of the most recent stack test.~~

~~By no later than January 1, 2017, Chevron shall conduct stack testing to establish the ratio of condensable PM2.5 from the FCC Catalyst Regenerator and SRUs. At that time the condensable fraction will be added and a new source-wide limitation shall be established in the AO.~~

ii. Source-wide NOx Cap

By no later than January 1, 2019, combined emissions of NOx 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.gf.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

Alkylation polymer: shall be determined from the latest edition of AP-42 (as fuel oil #6)

Diesel fuel: shall be determined from the latest edition of AP-42

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.12.gf.ii.A above apply until such time as stack testing is conducted as outlined below:

Initial NOx stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has been performed and shall be conducted at least 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: lbs/MMbtu shall be derived for each combustion type listed in IX.H.12.gf.ii.A above. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide NOx Cap shall be determined for each day as follows:

Total 24-hour NOx 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 NOx CEM shall be used to calculate daily NOx emissions from the FCC. Emissions shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by the flow rate of the flue gas. The NOx concentration in the flue gas shall be determined by a CEM as outlined in IX.H.11.f.

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.

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

~~Compliance with the daily limit shall be determined daily by multiplying the quantity of each fuel burned at each affected unit by the associated emission factor for that fuel at that unit, and summing the results.~~

~~Chevron shall maintain a record of fuel meter identifiers and locations, conversion factors, and other information required to demonstrate the required calculations. Records shall be kept showing the daily fuel usage, fuel meter readings, required fuel properties, hours of equipment operation, and calculated daily emissions.~~

~~The emission factors to be used for the above limitations are as follows:~~

~~Natural Gas/Plant Gas: by individual furnace/boiler*~~

~~*the most recent listing of these emission factors is maintained in Chevron's AO.~~

~~FCC Regenerator: The emission rate shall be determined by the FCC Regenerator NOx CEM~~

~~All other emission units shall be stack-tested if directed by the Director. Chevron may also perform a stack test to provide information for updating the emission factors.~~

iii. Source-wide SO2

By no later than January 1, 2019, combined emissions of SO2 shall not exceed 1.05 tons per

day (tpd) and 383.3 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:

FCC: The emission rate shall be determined by the FCC SO2 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.

Natural gas: EF = 0.60 lb/MMscf

Fuel oil & HF Alkylation polymer: The emission factor to be used for combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent acceptable to the Director, and the density of the fuel oil, as follows:

EF (lb SO2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO2/32 lb S)

Plant gas: the emission factor shall be calculated from the H2S measurement obtained from the H2S CEM.

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

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 the daily SO2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

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.

~~Daily SO2 emissions from affected units shall be determined by multiplying the quantity of each fuel used daily (24 hr usage) at each affected unit by the appropriate emission factor below. The values shall be summed to show the total daily sulfur dioxide emission.~~

~~Emission factors (EF) for the various fuels and emission points shall be as follows:~~

~~FCC Regenerator: The emission rate shall be determined by the FCC Regenerator SO2 CEM~~

~~SRUs: The emission rate shall be determined by multiplying the sulfur dioxide 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.~~

~~Natural gas: EF = 0.60 lb/MMscf~~

~~Fuel oil & HF Alkylation polymer: The emission factor to be used for combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent acceptable to the Director, and the density of the fuel oil, as follows:~~

~~EF (lb SO2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO2/32 lb S)~~

~~Plant gas: the emission factor shall be calculated from the H2S measurement obtained from the H2S CEM. The emission factor shall be calculated as follows:~~

~~EF (lb SO2/MMscf gas) = (24 hr avg. ppmdv H2S) /10^6 * (64 lb SO2/lb mole) * (10^6 scf/MMscf)/(379 scf/lb mole)~~

~~Chevron shall maintain a record of fuel meter identifiers and locations, conversion factors, and other information required to demonstrate the required calculations. Records shall be kept showing the daily fuel usage, fuel meter readings, required fuel properties, hours of equipment operation, and calculated daily emissions.~~

iv. Emergency and Standby Equipment and Alternative Fuels

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 NOx from each rich-burn compressor engine shall not exceed the following:

Engine Number	NO_x in ppmvd @ 0% O_2
1	236
2	208
3	230

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

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

g. Compass Minerals Ogden Inc.

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

Emission Points	Concentration (ppm)
Boiler #1	9.0
Boiler #2	9.0

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 once every three years subsequent to the initial compliance test.

ii. PM2.5 emissions to the atmosphere from each of the following emission points shall not exceed a concentration of 0.01 grains/dscf (@ 68 degrees F and 29.92 in Hg):

Source
SOP Plant Compaction/Loadout
Salt Plant Screening
SOP Plant Dryer D-001
SOP Plant Dryer D-002
SOP Plant Dryer D-003
SOP Plant Dryer D-004
SOP Plant Drying Circuit Fluid Bed Heater D-005
Salt Plant Dryer D-501

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 at least once every three years.

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

iii. PM2.5 emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Source	Concentration (grains/dscf) (@ 68 degrees F 29.92 in Hg)
SOP Loadout	0.01
SOP Silo Dust Collection	0.01
SOP Plant Compaction	0.020
Salt Plant Dust Collection	0.01

Bulk Truck Salt Loadout	0.0053
Mag Chloride Plant	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 at least once every three years.

iv. Dryer Requirements

A. By October 1, 2017, dryer units D-002 and D-004 shall be retired and removed from service

B. By January 1, 2017, emissions of NOx from all other dryers with heat input in excess of 5 MMBtu/hour shall not exceed 20 ppmvd at 3% O2

C. Compliance to the above NOx 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 at least once every three years.

~~Great Salt Lake Minerals Corporation: Production Plant~~

~~NOx emissions to the atmosphere from the indicated emission point shall not exceed the following concentrations:~~

~~Emission Points~~	~~Concentration (ppm)~~
~~Boiler #1~~	~~9.0~~
~~Boiler #2~~	~~9.0~~

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. A compliance test shall be performed at least once every three years subsequent to the initial compliance test.~~

ii. ~~PM10 emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:~~

~~Source~~	~~Concentration (grains/dscf)~~ ~~(@ 68 degrees F 29.92 in Hg)~~
~~SOP Plant Compaction/Loadout~~	~~0.01~~

~~Salt Plant Screening~~	~~0.01~~
~~SOP Plant Dryer D-001~~	~~0.01~~
~~SOP Plant Dryer D-002~~	~~0.01~~
~~SOP Plant Dryer D-003~~	~~0.01~~
~~SOP Plant Dryer D-004~~	~~0.01~~
~~SOP Plant Drying Circuit Fluid Bed Heater D-005~~	~~0.01~~
~~Salt Plant Dryer D-501~~	~~0.01~~

a. ~~Compliance to the above emission limits shall be determined by stack test as outlined in Section IX Part H.11a of this SIP. The stack test date shall be performed as soon as possible and in no case later than June 1, 2015 except for SOP Plant Dryer D-003 when a stack test shall be performed no later than January 1, 2016. A compliance test shall be done at least once every three years subsequent to the initial compliance test.~~

b. ~~Within one hundred and twenty (120) days after the initial compliance test date required above for each baghouse/scrubber, GSLM shall submit a Notice of Intent to DAQ in which a PM2.5 emission limit in grains/dscf and pounds/hour is proposed.~~

c. ~~c. Process emissions shall be routed through operating controls prior to being emitted into the atmosphere.~~

iii. ~~PM10 emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:~~

~~Source~~	~~Concentration (grains/dscf)~~ ~~(@ 68 degrees F 29.92 in Hg)~~
~~SOP Loadout~~	~~0.01~~
~~SOP Silo Dust Collection~~	~~0.01~~
~~SOP Plant Compaction~~	~~0.020~~
~~Salt Plant Dust Collection~~	~~0.01~~
~~Bulk Truck Salt Loadout~~	~~0.0053~~
~~Mag Chloride Plant~~	~~0.01~~

a. ~~Compliance to the above emission limits shall be determined by stack test as outlined in Section IX Part H.11a of this SIP. The stack test date shall be performed as soon as possible and in no case later than June 1, 2015. A compliance test shall be done at least once every five years subsequent to the initial compliance test.~~

b. ~~Within one hundred and twenty (120) days after the initial compliance test date required~~

~~above for each baghouse/scrubber, GSLM shall submit a Notice of Intent to DAQ in which a PM2.5 emission limit in grains/dscf and pounds/hour is proposed.~~

iv. ~~By January 1, 2017, Low NOx burner technology with a minimum manufacturer guarantee of 77% NOx removal efficiency shall be in operation on all dryers.~~

h. Hexcel Corporation: Salt Lake Operations

~~i. The following limits shall not be exceeded for Fiber Lines 2-8, 10-16, the Pilot Plant, and Matrix Operations:~~

~~A. 4.42 MMscf of natural gas consumed per day.~~

~~B. 0.061 MM pounds of carbon fiber produced per day.~~

~~C. Compliance with each limit shall be determined by the following methods:~~

~~I. Natural gas consumption shall be determined by examination of natural gas billing records for the plant.~~

~~II. Fiber production shall be determined by examination of plant production records.~~

~~III. Records of consumption and production shall be kept on a daily basis for all periods when the plant is in operation.~~

~~ii. All control equipment shall be in operation prior to initiating fiber line operations.~~

i. The following limits shall not be exceeded for fiber line operations:

A. 5.50 MMscf of natural gas consumed per day.

B. 0.061 MM pounds of carbon fiber produced per day.

C. Compliance with each limit shall be determined by the following methods:

I. Natural gas consumption shall be determined by examination of natural gas billing records for the plant and onsite pipe-line metering.

II. Fiber production shall be determined by examination of plant production records.

III. Records of consumption and production shall be kept on a daily basis for all periods when the plant is in operation.

v. After a shutdown and prior to startup of fiber lines 13 to 16, the line's baghouse(s) and natural gas injection dual chambered regenerative thermal oxidizer shall be started and remain in operation during production.

A. During fiber line production, the static pressure differential across the filter media shall be within the manufacturer's recommended range and shall be recorded daily.

B. The manometer or the differential pressure gauge shall be calibrated according to the manufacturer's instructions at least once every 12 months.

vi. After a shutdown and prior to startup of the fiber lines, the residence time and temperature

associated with the regenerative thermal-oxidation fume incinerators and solvent-coating fume incinerators shall be started and remain in operation during production.

A. Unless otherwise indicated, the carbon fiber production thermal-oxidation fume incinerators the minimum temperature shall be 1,400 deg F and the residence time shall be greater than or equal to 0.5 seconds

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

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

Residence times shall be determined by

Where
R = residence time
V = interior volume of the incinerator – ft3
Qmax = maximum exhaust gas flow rate – ft3/second

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

i. ~~Hill Air Force Base: Main Base~~

~~i. VOC emissions from painting and depainting operations shall not exceed 0.5 tons per day.~~

~~ii. Compliance with this daily average shall be determined monthly.~~

j. Holly Corporation: Holly Refining & Marketing Company (Holly Refinery)

i. Source-wide PM2.5 Cap

By no later than January 1, 2019, PM2.5 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.~~k~~i.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 PM2.5/MMscf
NSPS combustion equipment: 0.52 lb PM2.5/MMscf

Fuel oil:
The filterable PM2.5 emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

PM2.5 (lb/1000 gal) = (10 * wt. % S) + 3

The condensable PM2.5 emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.

FCC Wet Scrubbers:
The PM2.5 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

B. The default emission factors listed in IX.H.12.~~k~~i.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 once every three (3) years thereafter. At that time a new flow-weighted average emission factor in terms of: lb PM2.5/MMBtu shall be derived. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide PM2.5 Cap shall be determined for each day as follows:

Total 24-hour PM2.5 emissions for the emission points shall be calculated by adding the daily results of the PM2.5 emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the wet scrubbers to arrive at a combined daily PM2.5 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 on all gas-fueled combustion equipment.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply fuel oil to 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/Plant Gas Consumption (MMscf/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 all meter readings (in the appropriate units), and the calculated emissions.

~~PM2.5 emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:~~

~~Natural gas or Plant gas for all non-NSPS combustion equipment: 7.65 lb PM2.5/MMscf~~
~~Natural gas or Plant gas for all NSPS combustion equipment: 0.52 lb PM2.5/MMscf~~

~~Fuel oil: The filterable PM2.5 emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:~~

~~PM2.5 (lb/1000 gal) = (10 * wt. % S) + 3.22~~

~~The condensable PM2.5 emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.~~

~~Daily natural gas and plant gas consumption shall be determined through the use of flow meters on all gas-fueled combustion equipment.~~

~~Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply fuel oil to combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.~~

~~The equations used to determine emissions for the boilers and furnaces shall be as follows:~~

~~Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural/Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)~~

~~Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)~~

~~Total 24-hour PM2.5 emissions for the emission points shall be calculated by adding the daily results of the above PM2.5 emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt. %S), and the calculated emissions.~~

ii. Source-wide NOx Cap

By no later than January 1, 2019, NOx emissions into the atmosphere from all emission points shall not exceed 347.1 tons per rolling 12-month period and 2.09 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.~~k~~i.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:
Low NOx burners (LNB): 41 lbs/MMscf
Ultra-Low NOx (ULNB) burners: 0.04 lbs/MMbtu
Next Generation Ultra Low NOx 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.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 NOx Cap shall be determined for each day as follows:

Total daily NOx emissions for emission points shall be calculated by adding the results of the NOx 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.

~~NOx emissions shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted.~~

~~Natural gas/refinery fuel gas combustion using Low NOx burners (LNB): 41 lbs/MMscf Natural gas/refinery fuel gas combusted using Ultra-Low NOx burners: 0.04 lbs/MMbtu Natural gas/refinery fuel gas combusted using Next Generation Ultra Low NOx burners:~~
~~0.10 lbs/MMbtu~~
~~Natural gas/refinery fuel gas combusted burners using selective catalytic reduction (SCR):~~
~~0.02 lbs/MMbtu~~
~~All other natural gas/refinery fuel gas combustion burners: 100 lb/MMscf~~

~~All fuel oil combustion: 120 lbs/Kgal~~

~~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.~~

~~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. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.~~

~~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)~~

~~Total daily NOx emissions for emission points shall be calculated by adding the results of the~~
~~tabulated for every 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

By 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:

(lb of SO2/kgal) = (density lb/gal) * (1000 gal/kgal) * (wt. %S)/100 * (64 g SO2/32 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:

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/kgal) * Fuel Oil Consumption (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.

~~The routine turnaround maintenance period (a maximum of once every three years for a maximum of a 15 day period) for the SRU (Unit 17) shall only be scheduled during the period of April 1 through October 31. The projected SRU turnaround period shall be submitted to the Director by April 1 of each year in which a turnaround is planned. Notice shall also be provided to the Director 30 days prior to the planned turnaround.~~

~~SO2 emissions into the atmosphere shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel burned. SO2 emission factors for the various fuels shall be as follows:~~

~~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 in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily H2S content data from the CEM. The emission factor shall be calculated as follows:~~

~~(lb SO2/MMscf gas) = (24 hr avg. ppmv H2S)/10^6 * (64 lb SO2/lb mole) * (10^6 scf/MMscf)/(379 scf / lb mole)~~

~~Fuel oil - The emission factor to be used in conjunction with fuel oil combustion (during natural gas curtailments) shall be calculated based on the weight percent of sulfur, as determined by ASTM Method 0-4294-89 or EPA-approved equivalent, and the density of the fuel oil, as follows:~~

~~(lb of SO2/kgal) = (density lb/gal) * (1000 gal/kgal) * (wt. %S)/100 * (64 g SO2/32 g S)~~

~~The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may be combusted only during periods of natural gas curtailment.~~

~~Fuel Consumption shall be measured as follows:~~

~~Natural gas and plant gas consumption shall be determined through the use of flow meters.~~

~~Fuel oil consumption shall be measured each day by means of leveling gauges on all tanks that supply oil to combustion sources.~~

~~The equations used to determine emissions 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/kgal) * Fuel Oil Consumption (kgal/24 hrs)/(2,000 lb/ton)~~

~~Total daily SO2 emissions shall be calculated by adding daily results of the above SO2 emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day; and records shall be kept which include the CEM readings for H2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt. %S, recorded 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.

k. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

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

KUC shall keep records of daily total mileage for all periods when the mine is in operation. KUC shall track haul truck miles with a Global Positioning System or equivalent. The system shall use real time tracking to determine daily mileage.

~~B. The following source-wide emission limits at the BCM shall not be exceeded:~~

~~I. 6,205 tons of NOX, PM2.5 and SO2 combined per rolling 12-month period until January 1, 2019.~~

~~II. After January 1, 2019, combined emissions of NOX, PM2.5, and SO2 shall not exceed 5,585 tons per rolling 12 month period.~~

~~Compliance with the 12-month period limits shall be determined on a rolling 12-month total based on the previous 12 months per methodology outlined in Emissions Inventory. KUC shall calculate a new 12-month total by the 20th day of each month using data from the previous 12 months. [R307-401-8]~~

B. To minimize fugitive dust on roads at the mine, the owner/operator shall perform the following measures:

I. Apply water to all active haul roads as weather and operational conditions warrant except during precipitation or freezing weather conditions, and shall apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.

II. Chemical dust suppressant shall be applied as weather and operational conditions warrant except during precipitation or freezing weather conditions on unpaved access roads that receive haul truck traffic and light vehicle traffic.

III. Records of water and/or chemical dust control treatment shall be kept for all periods when the BCM is in operation.

IV. KUC is subject to the requirements in the most recent federally approved Fugitive Emissions and Fugitive Dust rules.

~~I. Apply water to all active haul roads as conditions warrant, and shall~~

~~1. ensure the surface of the active haul roads located within the pit influence boundary consists of road base material, blasted waste rock, crushed rock, or chemical dust suppressant, and~~

~~2. apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.~~

C. To minimize emissions at the mine, the owner/operator shall:

I. Control emissions from the in-pit crusher with a baghouse.

~~II. Ore conveyors shall be the primary means for transport of crushed ore from the mine to the concentrator.~~

~~III. Chemical dust suppressant shall be applied as conditions warrant on unpaved access roads that receive haul truck traffic and light vehicle traffic.~~

D. Implementation Schedule

KUC shall purchase new haul trucks with the highest engine Tier level available which meet mining needs. KUC shall maintain records of haul trucks purchased and retired.

~~I. KUC shall reduce emissions of combined PM2.5, SOx and NOx on a 12-month rolling period by 10% to 5,585 tons by 2019. In doing so, KUC is required to purchase the highest tier level trucks available that meet the production requirement, from certified manufactures.~~

ii. Copperton Concentrator (CC)

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

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

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

l. Kennecott Utah Copper: Power Plant

i. UTAH POWER PLANT

A. After January 1, 2018, boiler units #1, #2, and #3 shall not operate during the period November 1 to February 28/29 inclusive. Boiler units #1, #2, and #3 shall be decommissioned and removed upon commencement of unit #5 operations. ~~Boilers #1, #2, and #3 shall not be operated after January 1, 2018, or upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine), whichever is sooner~~

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

POLLUTANT	lb/hr	lb/event	ppmdv (15% O2 dry)
I. PM2.5 with duct firing: Filterable + condensable	18.8		
II. VOC:			2.0*
III. NOx:			2.0*
Startup / Shutdown		395	

* Except during startup and shutdown.~~Under steady state operation~~

IV. Startup / Shutdown Limitations:

1. The total number of startups and shutdowns together shall not exceed 690 per calendar year.

2. The NOx 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. ~~Stack testing to show compliance with the above Unit #5 emission limitations shall be performed as follows:~~

~~POLLUTANT TEST FREQUENCY~~

~~I. NOx: 3 years~~
~~II. VOC: 3 years~~

~~III. PM2.5 3 years~~

~~The heat input during all compliance testing shall be no less than 90% of the design rate.~~

Upon commencement of operation of Unit #5*, stack testing to demonstrate compliance with the emission limitations in IX.H.12.k.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.	PM2.5	every year
II.	NOx	every year
III.	VOC	every year

~~D. The following requirements are applicable to Unit #4 during the period November 1 to February 28/29 inclusive:~~

~~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. 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.~~

~~II. Except during a curtailment of 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% O2)~~
~~68°F, 29.92 in. Hg~~

~~1. Before January 1, 2018~~

~~a. PM2.5~~

~~filterable 0.004~~
~~filterable + condensable 0.03~~

~~b. NOx: 336~~

~~2. After January 1, 2018~~

~~a. PM2.5~~

~~filterable~~	~~0.004~~
~~filterable + condensable~~	~~0.03~~

~~b. NOx: 60~~

~~III. When using coal 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 68°F, 29.92 in. Hg~~	~~lb/hr~~	~~ppmdv (3% O2)~~
~~1. PM2.5~~			
~~filterable~~	~~0.029~~	~~33.5~~	
~~filterable + condensable~~	~~0.29~~	~~382~~	
~~II. NOx:~~			~~384~~

~~IV. Stack testing to show compliance with the emission limitations in H.12.m.i.D.II and III shall be performed as follows for the following air contaminants:~~

~~POLLUTANT~~	~~TEST FREQUENCY~~
~~1. PM2.5~~	~~every year~~
~~2. NOx~~	~~every year~~

~~The heat input during all compliance testing shall be no less than 90% of the design rate.~~

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

~~V. KUC shall operate Units 4 & 5 in accordance with best management practices to limit emissions of NOx during periods of startup and shutdown.~~

D. Prior to January 1, 2018, the following requirements are applicable to Units #1, #2, #3, and #4 during the period November 1 to February 28/29 inclusive:

I. Only natural gas shall only 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 68°F, 29.92 in. Hg	ppmdv (3% O2)
1. PM2.5 Units #1, #2, #3 and #4		
filterable	0.004	
filterable + condensable	0.03	
2. NOx		
Units #1, #2 and #3		336
3. NOx:		
Unit #4		336
(Unit #4 after January 1, 2018		60

III. When using coal 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% O2) 68°F, 29.92 in. Hg
1. PM2.5		
Filterable	0.029	
filterable + condensable	0.29	
2. NOx:		
Units #1, #2 and #3		426.5
Unit #4		384

IV. If the units are operated during the months specified above, stack testing to show compliance with the emission limitations in H.12.k.i.D.II and III shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency	Initial Test
1. PM2.5	every year	#
2. NOx	every year	#

Initial compliance testing is required for Unit #4 after low NOx burner installation. 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 heat input during all compliance testing shall be no less than 90% of the design rate.

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

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

E. The following requirements are applicable to Units #1, #2, #3, and #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% O2) 68°F, 29.92 in Hg
1. Units #1, #2, #3, #4		
(i) PM2.5 filterable	0.029	
(ii) filterable + condensable	0.29	
(iii) NOx Units #1, #2, #3		426.5
(iv) NOx Unit #4		384

II. If the units are operated during the months specified above, stack testing to show compliance with the emission limitations in H.12.k.i.E.I shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency
1. PM2.5	every year
2. NOx	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 Units #1, #2, #3 or #4.

~~ii. BONNEVILLE BORROW AREA PLANT~~

~~A. Maximum total mileage per day for haul trucks shall not exceed 12,500 miles.~~

m. Kennecott Utah Copper: Smelter and Refinery

i. SMELTER:

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

I. Main Stack (Stack No. 11)

1. PM2.5
   a. 85 lbs/hr (filterable)
   b. 434 lbs/hr (filterable + condensable)

2. SO2
   a. 552 lbs/hr (3 hr. rolling average)
   b. 422 lbs/hr (daily average)

3. NOx 154 ~~35~~ lbs/hr (~~annual~~ daily average)

II. ~~Acid Plant Tail Gas~~

~~1. SO2~~
~~a. 1,050 ppmdv (3 hr. rolling average)~~
~~b. 650 ppmdv (6 hr. rolling average)~~

II. Holman Boiler

1. NOx
   a. 14.0 ~~9.34~~ lbs/hr, (calendar-day ~~30-day~~ average)
   ~~b. 0.05 lbs. MMBTU, 30-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)	PM2.5	Every Year
	SO2	CEM
	NOx	CEM
~~II. Acid Plant Tailgas~~	~~SO2~~	~~CEM~~
II. Holman Boiler	NOx	Every three years and ~~CEM or~~ alternate method ~~determined~~ according to applicable NSPS standards

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

C. During startup/shutdown operations, NOx 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	NOx	9.5 lbs/hr
Combined Heat Plant	NOx	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
Tankhouse Boilers	NOx	every three years*
Combined Heat Plant	NOx	every year

Stack testing shall be performed on boilers that have operated more than 300 hours during a three year period.~~* To determine mass emission rate, 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. Provided that the two boilers installed are identical in make, model, and pollution control equipment, compliance with the emission limitation by the second boiler shall be determined by the stack test of the first boiler.~~

C. 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. ~~The owner/operator shall use only natural gas or landfill gas as a primary fuel in the boilers. The boilers may be equipped to operate on #2 fuel oil; however, operation of the boilers on #2 fuel oil shall only occur during periods of natural gas curtailment and during testing and maintenance periods. Operation of the boilers on #2 fuel oil shall be reported to the Director within one working day of start-up. Emissions resulting from operation of the boiler on #2 fuel oil shall be reported to the Director within 30 days following the use of #2 fuel oil in the boilers.~~

iii. Molybdenum Autoclave Project (MAP)~~MAP~~:

A. Emissions to the atmosphere from the Natural Gas Turbine ~~combined with Duct Burner and with TEG Firing~~ shall not exceed the following rate:

EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
Combined Heat Plant	NOx	5.01 lbs/hr

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

EMISSION POINT	POLLUTANT	TESTING FREQUENCY
Combined Heat Plant	NOx	every year

~~To determine mass emission rates (lbs/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.~~

C. Records shall be kept on site which indicate the date and time of startups and shutdowns.~~Standard operating procedures shall be followed during startup and shutdown operations to minimize emissions.~~

n. Nucor Steel Mills

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

A. Electric Arc Furnace Baghouse

I. PM2.5
1. 17.4 lbs/hr (24 hr. average filterable only)
2. 29.53 lbs/hr (condensable only)

II. SO2
1. 93.98 lbs/hr (3 hr. rolling average)
2. 89.0 lbs/hr (daily average)

III. NOx 59.~~7~~5 lbs/hr (calendar-day ~~12-month rolling~~ average)

IV. VOC 22.20 lbs/hr

B. Reheat Furnace #1

NOx 15.0 lb/hr

C. Reheat Furnace #2

NOx 8.0 lb/hr

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

EMISSION POINT	POLLUTANT	TEST FREQUENCY
A. Electric Arc Furnace Baghouse	PM2.5	every year
	SO2	CEM
	NOx	CEM
	VOC	every ~~5~~ year~~s~~
B. Reheat Furnace #1	NOx	every ~~3~~ year~~s~~
C. Reheat Furnace #2	NOx	every ~~3~~ year~~s~~

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

A. To demonstrate compliance with the Electric Arc Furnace stack mass emissions limits for SO2 and NOx of Condition (i)(A) above, Nucor shall calibrate, maintain and operate the measurement systems for continuously monitoring for SO2 and NOx concentrations and stack gas volumetric flow rates in the Electric Arc Furnace stack. Such measurement systems shall meet the requirements of R307-170.

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

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

o. Olympia Sales Company: Cabinet Manufacturing Facility

i. ~~By January 1, 2015,~~ By July 31, 2018, a baghouse control device shall be in operation for control of the process exhaust streams from the Mill, Door, and Sanding areas.~~installed and operating for control of PM from the process exhaust streams from the mill, door, and sanding areas.~~

ii. Process emissions from the ~~mill~~Mill, ~~door~~Door, and ~~sanding~~ Sanding areas shall be exhausted through the baghouse during ~~all~~ startup, shutdown, and ~~normal~~ operations of the plant.

iii. The baghouse shall operate a maximum of 4,160 hours per rolling 12-month period. Records of baghouse operation shall be kept for all periods of plant operation. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log.

iv. The owner/operator shall ~~use High Volume Low Pressure (HVLP) spray guns or equivalent for all painting processes at this facility~~comply with all applicable provisions of R307-349.

p. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

A. Emissions of NOx shall be no greater than 179 lbs/hr on a three (3) hour block average basis.

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NOx and O2 monitors to determine compliance with the NOx limitation. The CEM shall operate as outlined in IX.H.11.f.

ii. Steam Generating Unit #2:

A. Emissions of NOx shall be no greater than 204 lbs/hr on a three (3) hour block average basis.

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 monitors to determine compliance with the NOx limitation.

iii. Steam Generating Unit #3:

A. Emissions of NOx shall be no greater than

I. 142 lbs/hr on a three (3) hour block average basis, applicable between November 1 and February 28/29

II. 203 lbs/hr on a three (3) hour block average basis, applicable between March 1 and October 31

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NOx and O2 monitors to determine compliance with the NOx limitation. The CEM shall operate as outlined in IX.H.11.f.

iv. Steam Generating Units #1-3:

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

v. Natural Gas-fired Simple Cycle Turbine Units:

A. Total emissions of NOx from all three turbines shall be no greater than 600 lbs/day. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NOx and O2 monitors to determine compliance with the NOx limitation. The CEM shall operate as outlined in IX.H.11.f.

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

A. Startup begins when the fuel values open and natural gas is supplied to the combustion turbines

B. Startup ends when either of the following conditions is met:

I. The NOx water injection pump is operational, the dilution air temperature is greater than 600ºF, the stack inlet temperature reaches 570ºF, the ammonia block value has opened and ammonia is being injected into the SCR and the unit has reached an output of ten (10) gross MW; or

II. The unit has been in startup for two (2) hours.

C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross MW with the intent of removing the unit from service.

D. Shutdown ends at the cessation of fuel input to the turbine combustor.

E. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.

F. Turbine output (turbine load) shall be monitored and recorded on an hourly basis with an electrical meter.

~~i. Steam Generating Unit #1:~~
~~A. Emissions of NOx shall be no greater than 336 ppmdv (3% O2, dry).~~

~~B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 m onitors to determine compliance with the NOx limitation.~~

~~ii. Steam Generating Unit #2:~~
~~A. Emissions of NOx shall be no greater than 336 ppmdv (3% O2, dry).~~

~~B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 monitors to determine compliance with the NOx limitation.~~

~~iii. Steam Generating Unit #3:~~
~~A. Emissions of NOx shall be no greater than 336 ppmdv (3% O2, dry).~~

~~B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 monitors to determine compliance with the NOx limitation.~~

~~iv. Natural Gas-fired Simple Cycle Turbine Units:~~
~~A. Total emissions of NOx from all three turbines shall be no greater than 22.2 lbs/hour (15% O2, dry) based on a 30-day rolling average.~~

~~B. Emission of NOx from each individual turbine shall be no greater than 5 ppmdv (15% O2, dry) based on 30 day rolling average.~~

~~C. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 monitors to determine compliance with the applicable NOx limitations. The NOx emission rate (lb/hr) shall be calculated by multiplying the NOx concentration (ppmdv) generated~~

~~from CEMs and the volumetric flow rate.~~

~~D. The owner/operator shall expand the catalyst beds to achieve additional NOx control on Natural Gas-fired Simple Cycle Turbine Units (Units #4, #5 and #6) by no later than January 1, 2016~~

~~v. Combustion Turbine Startup / Shutdown Emission Minimization Plan~~

~~A. Startup begins when the fuel values open and natural gas is supplied to the combustion turbines~~

~~B. Startup ends when either of the following conditions is met:~~

~~I. The NOx water injection pump is operational, the dilution air temperature is greater than 600 oF, the stack inlet temperature reaches 570 oF, the ammonia block value has opened and ammonia is being injected into the SCR and the unit has reached an output of ten (10) gross MW; or~~

~~II. The unit has been in startup for two (2) hours.~~

~~C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross MW with the intent of removing the unit from service.~~

~~D. Shutdown ends at the cessation of fuel input to the turbine combustor.~~

~~E. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.~~

q. Tesoro Refining and Marketing Company: Salt Lake City Refinery

i. Source-wide PM2.5 Cap

By no later than January 1, 2019, combined emissions of PM2.5 (filterable + condensable) shall not exceed 2.25 tons per day (tpd) and 179 tons per rolling 12-month period.~~By no later than January 1, 2019, combined emissions of filterable PM2.5 shall not exceed 0.42 tons per day (tpd) and 110 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.~~r~~p.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM2.5: 1.9 lb/MMscf
Condensable PM2.5: 5.7 lb/MMscf

Plant gas:
Filterable PM2.5: 1.9 lb/MMscf
Condensable PM2.5: 5.7 lb/MMscf

Fuel Oil: The PM2.5 emission factor shall be determined from the latest edition of AP-42

FCC Wet Scrubber:
The PM2.5 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

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.12.~~r~~p.i.A above apply until such time as stack testing is conducted as outlined below:

Initial PM2.5 stack testing on the FCC wet gas scrubber stack shall be conducted no later than January 1, 2019 and at least once every three (3) years thereafter. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the Source-wide PM2.5 Cap shall be determined for each day as follows:

Total 24-hour PM2.5 emissions for the emission points shall be calculated by adding the daily results of the PM2.5 emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the wet scrubber to arrive at a combined daily PM2.5 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:

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.

~~PM2.5 emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:~~

~~Natural gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)~~
~~Plant gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)~~

~~Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points.~~

~~The equations 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)~~

~~By no later than January 1, 2019, Tesoro shall conduct stack testing to establish the ratio of condensable PM2.5 from the FCCU wet gas scrubber stack. At that time the condensable fraction will be added and a new source-wide limitation shall be established in the AO.~~

~~Total 24-hour PM2.5 (filterable + condensable) emissions shall be calculated by adding the results of the above filterable PM2.5 equations for natural gas and plant gas combustion to the values for the FCCU wet gas scrubber stack and to the estimate for the SRU/TGTU/TGI. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.~~

ii. Source-wide NOx Cap
By no later than January 1, 2019, combined emissions of NOx shall not exceed 1.988 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.~~r~~p.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:
Low NOx burners (LNB): 41 lbs/MMbtu
Ultra-Low NOx (ULNB) burners: 0.04 lbs/MMbtu
Diesel fuel: shall be determined from the latest edition of AP-42

B. The default emission factors listed in IX.H.12.~~r~~p.ii.A above apply until such time as stack testing is conducted as outlined below:

Initial NOx stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has already been performed and shall be conducted at least once every three (3) years following the date of the last test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.12.~~r~~p.ii.A above. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide NOx Cap shall be determined for each day as follows:

Total 24-hour NOx 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 NOx CEM shall be used to calculate daily NOx 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 NOx concentration in the flue gas shall be determined by a CEM as outlined in IX.H.11.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.

~~Compliance shall be determined daily 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 NOx CEM shall be used to calculate daily NOx emissions from the FCCU wet gas scrubber stack. Emissions shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by the mass flow of the flue gas. The NOx concentration in the flue gas shall be determined by a CEM.~~

~~The emission factors for all other emission units are based on the results of the most recent stack test for that unit.~~

~~Total daily NOx emissions shall be calculated by adding the emissions for each emitting unit. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.~~

iii. Source-wide SO2 Cap

By no later than January 1, 2019, combined emissions of SO2 shall not exceed 3.1 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 = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
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.

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 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.

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.

~~Daily SO2 emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO2 concentration in the flue gas by the mass flow of the flue gas. The SO2 concentration in the flue gas shall be determined by a CEM.~~

~~Daily SO2 emissions from other affected units shall be determined by multiplying the quantity of each fuel used daily (24 hour usage) at each affected unit by the appropriate emission factor below.~~

~~Emission factors (EF) for the various fuels shall be as follows:~~

~~Natural gas: EF = 0.60 lb/MMscf~~
~~Propane: EF = 0.60 lb/MMscf~~

~~Plant fuel gas: the emission factor shall be calculated from the H2S measurement or from the SO2 measurement obtained by direct testing/monitoring.~~

~~The emission factor, where appropriate, shall be calculated as follows:~~

~~EF (lb SO2/MMscf gas) = [(24 hr avg. ppmdv H2S) /10^6] [(64 lb SO2/lb mole)] [(10^6 scf/MMscf)/(379 scf/lb mole)]~~

~~Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.~~

~~Total daily SO2 emissions shall be calculated by adding the daily results of the above SO2 emissions equations for natural gas, plant fuel gas, and propane combustion to the wet gas scrubber stack. Results shall be tabulated every day, and records shall be kept which include~~

~~the CEM readings for H2S (averaged for each one-hour period), all meter readings (in the appropriate units), 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.

r. 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: Boilers (Each)

Pollutant	Oxygen Ref.	lb/hr
NOx	3%	3.3
$PM_{2.5(Filterable)}$	3%	0.72

Source: Paper Machines Process Stacks (Each)

Pollutant	Oxygen Ref.	lb/hr
NO_X	3%	13.50
$PM_{2.5(Filterable)}$	3%	6.65

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. By no later than January 1, 2015, stack testing shall be completed to establish the ratio of condensable PM2.5. At that time the condensable fraction will be added and a PM2.5 limit established in the AO.

C. Subsequent to initial compliance testing, stack testing is required at a minimum of every ~~five~~ 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 the cessation of natural gas flow to the dryer combustion equipment. Shutdown conditions end within thirty (30) minutes of hot air being diverted to the dryer startup stack.

s. University of Utah: University of Utah Facilities

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

Emissions Point	Pollutant	ppmdv (3% O2 dry)
A. Boilers #3	NOx	187
B. Boilers #4a & 4b*	NOx	9
C. Boilers #5a & 5b	NOx	9
D. Turbine	NOx	9
E. Turbine and WHRU Duct burner	NOx	15

*Boiler #4 will be replaced with Boiler #4a and #4b by 2018.

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
A. Boilers #3	NOx	*	every 3 years
B. Boilers #4a & #4b	NOx	2018	every 3 years
C. Boilers #5a & #5b	NOx	2017	every 3 years
D. Turbine	NOx	*~~2014~~	every 3 years
E. Turbine and WHRU Duct Burner	NOx	*~~2014~~	every 3 years

Initial test already performed
* Initial tests have been performed and the next method test using EPA approved test methods shall be performed within 3 years of the last stack test.

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

iii. After January 1, 2019, Boiler #3 shall only be used as a back-up/peaking boiler and shall not exceed 300 hours of operation per rolling-12 months. Boiler #3 may be operated on a continuous basis if it is equipped with low NOx burners or is replaced with a boiler that has low NOx burners. The burners shall have a NOx rating that are 9 ppm or less.

~~iii. Testing Status (To be applied to A, B, C, D, and E in i and ii above)~~

~~A. After January 1, 2019, Boiler #3 shall only be used as a back-up/peaking boiler. Unit #3 may be operated on a continuous basis with a boiler(s) that is equipped with low NOx burners.~~

~~B. To be applied to boilers #4a, #4b, #5a, and #5b, initial test shall be performed by February 28th of the year specified.~~

~~C. To be applied to boilers #4a, #4b, #5a, and #5b , testing will be performed at least every 3 years, between November 1 and February 28/29.~~

~~D. To be applied to turbine, and turbine and WHRU Duct Burner, testing will be performed a t least every year between November 1 through February 28/29.~~

iv. ~~Standard operating procedures shall be followed during startup and shutdown operations to minimize emissions.~~Records shall be kept on site which indicate the date, and time of startup and shutdown.

~~v. Units 1 & 3 of Building 302 shall have a combustion control system with automatic O2 trim installed by December 2014~~

t. Utah Municipal Power Association: West Valley Power Plant.~~CER Generation II, LLC (Exelon Generation): West Valley Power Plant~~

i. Total emissions of NOx from all five (5) turbines combined shall be no greater than 1050 lb of NOx 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. Total emissions of NOx from all five (5) turbines shall include the sum of all periods in the day including periods of startup, shutdown, and maintenance.

iii. The NOx emission rate (lb/hr) shall be determined by CEM. The CEM shall operate as outlined in IX.H.11.f.

~~i. Emissions of NOx from each individual turbine shall be no greater than 5 ppmdv (15% O2, dry) based on a 30-day rolling average.~~

~~ii. Total emissions of NOx from all five turbines shall be no greater than 37 lbs/hour (15% O2, dry) based on a 30-day rolling average.~~

~~iii. The NOx emission rate (lb/hr) shall be calculated by multiplying the NOx concentration (ppmdv) generated from CEMs and the volumetric flow rate. The 30-day rolling average shall be calculated by adding previous 30 days data on a daily basis.~~

~~iv. Combustion Turbine Startup / Shutdown Emission Minimization Plan~~

~~A. Startup begins when natural gas is supplied to the combustion turbine(s) with the intent of combusting the fuel to generate electricity. Startup conditions end within sixty (60) minutes of natural gas being supplied to the turbine(s).~~

~~B. Shutdown begins with the initiation of the stop sequence of a turbine until the cessation of natural gas flow to the turbine.~~

~~C. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.~~

u. ~~Vulcraft / Nucor Building Systems~~

i. ~~R307-350 Miscellaneous Metal Parts and Products Coatings applies to the painting operations at Vulcraft and Nucor Building Systems.~~

ii. ~~The combined source-wide emissions of VOCs from the joist dip tanks, paint booths, spray painting, degreasers, parts cleaners, and associated operations from the Vulcraft Joist plant and the Nucor Building Systems plant shall not exceed 305.07 tons per rolling 12- month period after January 1, 2014. VOCs emissions shall be calculated from paint and solvent usage based on inventory records.~~

v. Wasatch Integrated Waste Management District

Energy Recovery Facility

i. By January 1, 2018, SNCR technology shall be installed and operating on each of the two Municipal Waste Combustors for the reduction of NOx emissions.

ii. By January 1, 2018, Eemissions of NO_x from the Municipal Waste Combustors shall not exceed 350 320 ppmdv (7% O2, dry basis), based on a 24-hour daily arithmetic average concentration.

iii. Compliance shall be determined by CEMs.

A. Compliance with the NO_x limitation shall be determined by operation of CEMS. The operation of the CEMS shall be in accordance with IX.H.11.f.

iii. Emissions of SO_2 from the Municipal Waste Combustors shall not exceed 31 ppmdv (7% O2, dry basis), based on a 24-hour daily block geometric average concentration.

A. Compliance with the SO_2 limitation shall be determined by operation of CEMS. The operation of the CEMS shall be in accordance with IX.H.11.f.

iv. Emissions of $PM_{2.5}$ from the Municipal Waste Combustors shall not exceed 27 milligrams (filterable) per dry standard cubic meter (Averaging Time: 3-run average), based on a run duration specified in the test method.

A. Compliance with the $PM_{2.5}$ limitation shall be determined by stack testing. The stack testing shall be done in accordance with IX.H.11.e.

v. Gas Suspension Absorber (GSA) and PAC Injection

A. The control system for the GSA shall automatically shut-down or start-up the feeder screws, slurry pumps, and PAC feeder based upon minimum required gas flows and temperature.

B. The facility shall follow the Operations and Maintenance Manual shall ensure the GSA is operated as long as possible during startup/shutdown:

I. Cold Light Off
The GSA is placed into startup sequence during final heating when the ESP inlet temperature reaches 285 degrees Fahrenheit and coincident to introducing MSW to the unit.

II. Hot Light Off
The GSA is placed into startup sequence during final heating when the ESP inlet temperature reaches 285 degrees Fahrenheit and coincident to introducing MSW to the unit.

III. Secure to Hot
Continue operations of the GSA after stopping feeding of refuse until ESP inlet temperature drops below 285 degrees Fahrenheit.

IV. Secure to Cold
Continue operations of the GSA after stopping feeding of refuse until ESP inlet temperature drops below 285 degrees Fahrenheit.

V. Malfunction Shut Down
Continue operations of the GSA after stopping feeding of refuse until ESP inlet temperature drops below 285 degrees Fahrenheit.

The GSA and PAC injection operations shall be recorded and documented in an operations log. The log shall record the hours operated, date, and time during start-up/shut-down events.

vi. Electrostatic Precipitator (ESP)

A. Each unit is equipped with an ESP for control of particulate emissions. The ESPs shall be operated in accordance with the facility Operations and Maintenance Manual. The facility Operations and Maintenance Manual shall ensure the ESP is operated as long as possible during start-up/shut-down:

I. Cold Light Off
The ESP is lined up and placed into operation prior to lighting burners and well before introducing MSW to the unit.

II. Hot Light Off
The ESP is lined up and placed into operation prior to lighting burners and well before introducing MSW to the unit.

III. Secure to Hot
Continue operations of the ESP throughout shutdown period as possible.

IV. Secure to Cold
Continue operations of the ESP throughout shutdown period as possible.

V. Malfunction Shut Down
Continue operations of the ESP throughout shutdown period as possible.

All operations of the ESPs shall be documented in an operations log. This log shall record the hours operated, date, and times during start-up/shut-down events.

Landfill Operation

i. The owner/operator shall be subject to and comply with the requirements of 40 CFR 63 Subpart AAAA (National Emission Standards for Hazardous Air Pollutants: Municipal Solid Waste Landfills)

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

a. Brigham Young University: Main Campus

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

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

Emission Point	Pollutant	ppm (7% O2 dry) *		lb/hr	
A. Unit #1	NOx	95	36	9.55	5.44
B. Unit #4	NOx	127	36	38.5	19.2
C. Unit #6	NOx	127	36	38.5	19.2

* Unit #1 NOx limit is 95 ppm (9.55 lb/hr) until it operates for more than 300 hours during a rolling 12-month period, then the limit will be 36 ppm (5.44 lb/hr). The NOx limit for units #4 and #6 is 127 ppm (38.5 lb/hr) and starting on December 31, 2018, the limit will then be 36 ppm (19.2 lb/hr).

Emission Point	Pollutant	ppm (7% O2 dry)	lb/hr
D. Unit #2	NOx	331	37.4
	SO2	597	56.0
E. Unit #3	NOx	331	37.4
	SO2	597	56.0
F. Unit #5	NOx	331	74.8
	SO2	597	112.07

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

EMISSION POINT	POLLUTANT	INITIAL TEST	TEST FREQUENCY
A. Unit #1	NOx	&	every year*
B. Unit #2	NOx	#	every year*
C. Unit #3	NOx	#	every year*
D. Unit #4	NOx	#	every year*
E. Unit #5	NOx	#	every year*
F. Unit #6	NOx	#	every year*

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

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

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

~~iv. Natural Gas-Fired Boilers~~
~~A. Central Heating Plant Natural Gas-Fired Boilers~~
~~I. Startup and shutdown events shall not exceed 216 hours per boiler per 12-month rolling period.~~
~~II. The owner/operator of Unit #4 and Unit #6 shall replace the burner spud tips with low NOx tips and add a minimum of 18% Flue Gas Recirculation. Other modifications include installing combustion controls fully metered with oxygen trim. The modifications shall be completed by January 1, 2017.~~

iv. Central Heating Plant Coal-Fired Boilers

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

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

I. 0.54 pounds of sulfur per million BTU heat input as determined by ASTM Method D-4239-85, or EPA-approved equivalent acceptable to the Director.

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

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

III. Determine the weight percent sulfur and the fuel heating value by submitting a coal

sample to a laboratory, acceptable to the Director, on no less than a monthly basis; or

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

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

v. Central Heating Plant Boilers

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

b. Geneva Nitrogen Inc.: Geneva Nitrogen Plant

i. Prill Tower:

~~PM10 emissions shall not exceed 0.22 ton/day and 79 ton/yr~~
PM10 emissions (filterable and condensable) shall not exceed 0.236 ton/day
PM2.5 emissions (filterable and condensable) shall not exceed 0.196 ton/day

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

ii. Testing

A~~D~~. Stack testing shall be performed as specified below:

~~I. Frequency. Emissions shall be tested every three years. The source shall also be tested at any time as required by the Director.~~
I. Frequency: Emissions shall be tested every three years. The test shall be performed as soon as possible and in no case later than December 31, 2017.

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

iii. Montecatini Plant:

NOx emissions shall not exceed 30.8 lb/hr

iv. Weatherly Plant:

NOx emissions shall not exceed 18.4 lb/hr

v. Testing:

~~Compliance testing is required on the Prill tower, Montecatini Plant, and Weatherly Plants. The test shall be performed as soon as possible and in no case later than January 1, 2019.~~

~~F. Stack testing to show compliance with the NOx emission limitations shall be performed as specified below:~~

~~I. Testing and Frequency. Emissions shall be tested every three years. The source may also be tested at any time as required by the Director.~~

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

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

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

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

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

2. Performance Criteria:

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

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

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

~~I. Measurement Approach: NOx concentration (ppmdv) shall be determined by using a NOx CEM.~~

~~II. Indicator Range: An excursion is defined as a one-hour average NOx concentration in excess of 200 ppmdv as measured by the NOx CEM. Excursions trigger an inspection, corrective action, and a reporting requirement.~~

~~III. Performance Criteria:~~

~~1. Data Representativeness: Measurements made by a continuous monitoring system shall provide a direct indicator of SCR performance. The low detectable limit is 0.01 ppmdv (in 0.5 ppmdv full scale range) and the precision is 1% of the full scale.~~

~~2. QA/QC Practices and Criteria: The continuous monitoring system shall be operated, calibrated, and maintained in accordance with manufacture's recommendations. Zero and span drift tests shall be conducted on a daily basis.~~

~~3. Monitoring Frequency: Emission shall be monitored continuously and a data point recorded every 15 seconds.~~

~~4. Data Collection Procedure: NOx concentration (ppmdv) shall be recorded and stored electronically.~~

~~5. Averaging Period: Use 15-second NOx concentration (ppmdv) to calculate hourly average NOx concentration (ppmdv).~~

vi. Start-up/Shut-down

A. Startup / Shutdown Limitations:

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

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

~~A. A low temperature catalyst shall be utilized in the abatement process so that the catalyst can be initiated at the lowest temperature possible while avoiding ammonium nitrate and ammonium nitrite condensation temperatures. Geneva Nitrogen shall initiate the SCR abatement process as soon as temperature permits and by using pure clean water in the absorption process for maximum absorption efficiency during start-up conditions.~~

~~B. The wet scrubbing system used for the reduction of PM10/PM2.5 in the Ammonium Nitrate Prill Tower shall be in operation either prior to or at the same time the scrubber initiates operation.~~

c. ~~Pacific States Cast Iron Pipe Company: Pipe Casting Plant~~McWane Ductile - Utah

i. ~~By January 1, 2015, all VOC emissions shall be limited to 140.85 tons per rolling 12-month period.~~

A. ~~By the twentieth day of each month, a new 12-month total shall be calculated using data from the previous 12 months.~~

B. ~~Records shall be kept for all periods the plant is in operation.~~

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

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

B. For purposes of this section a day is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

iii. The Annealing Oven furnaces are limited to 63.29 MMBtu/hr.

iv. Emissions from the desulfurization and ductile treatment system shall be routed through the operating baghouse prior to be emitted into the atmosphere.

v. Emissions from the Special Lining Shotblast operations shall be routed through the operating baghouse prior to being emitted into the atmosphere.

d. PacifiCorp Energy: Lake Side Power Plant

~~i. Block #1 Turbine/HRSG Stacks:~~
~~Emissions of NOx shall not exceed 2.0 ppmvd (15% O2) on a 3-hour average basis.~~

i. Block #1 Turbine/HRSG Stacks:

A. Emissions of NOx shall not exceed 14.9 lb/hr on a 3-hr average basis

B. Compliance with the above conditions shall be demonstrated as follows:

I. NOx monitoring shall be through use of a CEM as outlined in IX.H.11.f

~~ii. Block #2 Turbine/HRSG Stacks:~~
~~Emissions of NOx shall not exceed 2.0 ppmvd (15% O2) on a 3-hour average basis.~~

ii. Block #2 Turbine/HRSG Stacks:

A. Emissions of NOx shall not exceed 18.1 lb/hr on a 3-hr average basis

B. Compliance with the above conditions shall be demonstrated as follows:

I. NOx monitoring shall be through use of a CEM as outlined in IX.H.11.f

~~iii. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 monitors to determine compliance with the applicable NOx limitations.~~

iii. Startup / Shutdown Limitations:

A. Block #1:

I. Startup and shutdown events shall not exceed 613.5 hours per turbine per 12-month rolling period.
II. Total startup and shutdown events shall not exceed 14 hours per turbine in any one calendar day.

III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.

IV. During periods of transient load conditions, NOx emissions from the Block #1 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O2.

B. Block #2:

I. Startup and shutdown events shall not exceed 553.6 hours per turbine per 12-month rolling period.

II. Total startup and shutdown events shall not exceed 8 hours per turbine in any one calendar day.

III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.

IV. During periods of transient load conditions, NOx emissions from the Block #~~1~~ 2 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O2.

C. Definitions:

I. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr~~ppmvd~~ emission limits listed in IX.H.13.d~~e~~.i and ii above.

II. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine.

III. Transient load conditions are those periods, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmv dry @ 15% O2. Transient load conditions consist of the following:

1. Initiation/shutdown of combustion turbine inlet air-cooling.

2. Rapid combustion turbine load changes.

3. Initiation/shutdown of HRSG duct burners.

4. Provision of Ancillary Services and Automatic Generation Control.

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

e. Payson City Corporation: Payson City Power

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

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

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

~~iii. The emission factor shall be derived from the most recent emission test results. The source shall be tested every three years based on the date of the last stack test. Emissions for NOx shall be the sum of emissions from each engine and shall be calculated on a daily basis.~~
~~iv. The number of kilowatt hours generated by each engine shall be recorded on a daily basis.~~
~~v. Startup / Shutdown Limitations:~~
~~A. Startup and shutdown events shall not exceed 936 hours per rolling 12-month period.~~
~~B. Total startup and shutdown events shall not exceed six (6) hours in any one calendar day.~~
~~C. The daily startup and shutdown totals shall be summed across all four dual fuel engines.~~

A. The NOx emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.11.e. Each engine shall be tested at least every three years from the previous test.

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

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

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

f. Provo City Power: Power Plant

i. ~~Emissions of NOx shall be no greater than 2.45 tons per day and 254 tons per rolling 12-month period for all engines and boilers combined.~~

ii. ~~Compliance with the emission limitations shall be determined by the following equations:~~

~~Emissions (tons/rolling 12-month period) = (Power production in kW-hrs/day) x (Emission factor in grams/kW-hr) x (1 lb/453.59 g) x (1ton/2000 lbs)~~

~~Emissions (tons/rolling 12-month period) = (Power production in kW-hrs/rolling 12-month period) x (Emission factor in grams/kW-hr) x (1 lb/453.59 g) x (1ton/2000 lbs)~~

~~The emission factors for NOx shall be derived from the most recent emission test results.~~

iii. ~~Each engine and boiler shall be tested every 8,760 hours of operation and/or at least every five years based on the date of the last stack test, whichever occurs sooner.~~

iv. ~~NOx emissions shall be the sum of emissions from each engine and boiler. The number of kilowatt hours generated by each engine and boiler shall be recorded on a daily basis.~~

~~v. Startup / Shutdown Limitations:~~

~~A. Startup and shutdown events shall not exceed 936 hours per rolling 12-month period.~~

~~B. Total startup and shutdown events shall not exceed six (6) hours in any one calendar day.~~

~~C. The daily startup and shutdown totals shall be summed across all four dual fuel engines.~~

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

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

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

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

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

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

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

g. Springville City Corporation: Whitehead Power Plant

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

iv. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM as outlined in IX.H.11.f. A day is equivalent to the time period from midnight to the following midnight. Emissions of NOx shall be calculated for each individual engine by the following equation:

D = (X * K)/453.6

Where:

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

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

D = daily output of pollutant in lbs/day

~~i. Emissions of NOx shall be no greater than 1.68 ton per day and 248 tons per rolling 12-month period for all Unit Engines combined.~~
~~ii. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM. Emissions shall be calculated for NOx for each individual engine in the following manner:~~
~~Daily Rate Calculation:~~
~~X = grams/kW-hr rate for each generator (recorded by CEM)~~
~~K = total kW-hr generated by the generator each day (recorded by output meter)~~
~~D = daily output of pollutant in lbs/day~~
~~D = (X * K)/453.6~~
~~The daily outputs are summed into a monthly output.~~
~~The monthly outputs are summed into an annual rolling 12-month total of pollutant in tons/year.~~
~~iii. Startup / Shutdown Limitations:~~
~~A. Startup and shutdown events shall not exceed 1638 hours per rolling 12-month period.~~
~~B. Total startup and shutdown events shall not exceed 10.5 hours in any one calendar day.~~
~~C. The daily startup and shutdown totals shall be summed across all seven (7) dual fuel engines.~~

ITEM 9

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-045-16

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Ryan Stephens, Rules Coordinator

DATE: August 25, 2016

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.

The amendments to Section IX, Part H of the $PM_{2.5}$ and PM_{10} State Implementation Plan (SIP) will have to be incorporated into the Air Quality Rules. R307-110-17 is the rule that does this. If the Board adopts the amendments proposed to Part H, then those amendments will become part of Utah's SIP when this rule is eventually adopted by the Board.

Staff Recommendation: Staff recommends that the Board propose R307-110-17 for public comment.

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

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

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part H, Emission[~~s~~] Limits and Operating Practices, as most recently amended by the Utah Air Quality Board on [~~December 2~~]December 7, 201[~~5~~]6, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

KEY: air pollution, PM10, PM2.5, ozone
Date of Enactment or Last Substantive Amendment: [~~February 4,~~] 2016
Notice of Continuation: February 1, 2012
Authorizing, and Implemented or Interpreted Law: 19-2-104

NOTICE OF
PROPOSED RULE AMENDMENT

- The agency identified below in box 1 provides notice of proposed rule change pursuant to Utah Code Section 63G-3-301.
- Please address questions regarding information on this notice to the agency.
- The full text of all rule filings is published in the Utah State Bulletin unless excluded because of space constraints.
- The full text of all rule filings may also be inspected at the Office of Administrative Rules.

Rule Information

DAR file no: Date filed:

State Admin Rule Filing Key: 157860

Utah Admin. Code ref. (R no.): R307-110-17

Agency Information

1. Agency: ENVIRONMENTAL QUALITY - Air Quality

Room no.: Fourth Floor

Building:

Street address 1: 195 N 1950 W

Street address 2:

City, state, zip: SALT LAKE CITY UT 84116-3085

Mailing address 1: PO BOX 144820

Mailing address 2:

City, state, zip: SALT LAKE CITY UT 84114-4820

Contact person(s):

Name:	Phone:	Fax:	E-mail:	Remove:
Ryan Stephens	801-536-4419	801-536-0085	rstephens@utah.gov	

(Interested persons may inspect this filing at the above address or at DAR during business hours)

Rule Title

2. Title of rule or section (catchline):
Section IX, Control Measures for Area and Point Sources, Part H, Emissions Limits.

Notice Type

3. Type of notice: Amendment

Rule Purpose

4. Purpose of the rule or reason for the change:
   The purpose of this rule is to incorporate the recently amended Part H of the PM10 and PM2.5 State Implementation Plan (SIP) into the Utah Air Quality Rules. The amendments to Part H were made in response to comments submitted by the Environmental Protection Agency (EPA) on Utah's 2014 submission of the PM2.5 SIP. The changes are necessary for EPA to approve the PM2.5 SIP and the PM10 Maintenance Plan.

Response Information

5. This change is a response to comments by the Administrative Rules Review Committee.
   No Yes

Rule Summary

6. Summary of the rule or change:
   The amendments to the text of R307-110-17 change the title of the rule to match the title that is found in the SIP. The date has also been changed to reflect the most recent incorporation of Part H. Part H has been amended to include the following: 1) more frequent monitoring, 2) emission limits that match the 24-hour averaging period of the PM2.5 National Ambient Air Quality Standard, 3) condensable PM2.5 limits where appropriate, 4) corrections to the emission limits at Chemical Lime Company, 5) revisions to the compliance schedule for Compass Minerals, 6) elimination of the conditions for Hill Air Force Base and Vulcraft/Nucor Building Systems, 7) elimination of the provisions intended to facilitate the production of gasoline meeting the sulfur requirements of Tier 3, and 8) a requirement for Kennecott to operate its existing wet scrubber at the Copperton Concentrator.

Aggregate Cost Information

7. Aggregate anticipated cost or savings to:

A) State budget:

Affected: ◉ No ○ Yes

This rule will not have an impact on the state budget.

B) Local government:

Affected: ◉ No ○ Yes

This rule will not impact local governments.

C) Small businesses:

Affected: ○ No ◉ Yes

("small business" means a business employing fewer than 50 persons)

The businesses listed in Part H that employ less than 50 people will have to comply with the requirements of the SIP. The costs associated with Part H will mostly be made up of the costs associated with more frequent monitoring. The monitoring is required by federal law due to the states obligation to impose Reasonably Available Control Technology (RACT) on the sources listed in Part H. In order to determine RACT, cost is taken into consideration. Most of the costs required by part H were imposed in 2014 when the SIP was last amended for PM2.5.

D) Persons other than small businesses, businesses, or local government entities:

Affected: ◉ No ○ Yes

("person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an agency)

Other persons will not be directly impacted by this rule because the rule is regulating businesses.

Compliance Cost Information

8. Compliance costs for affected persons:

The compliance costs for the affected persons will mostly come from the costs associated more frequent monitoring requirements. For some sources this will be the cost of switching to continuous emission monitoring systems (CEMS). The cost may also be the price of more stack testing and parametric monitoring. This cost will vary depending on the size of the source and what equipment is needed. Cost was taken into account, as is required by the Clean Air Act, when the requirements of Part H were drafted.

Department Head Comments

9. A) Comments by the department head on the fiscal impact the rule may have on businesses:

The businesses listed in Part H will have to comply with the requirements of the SIP. The costs associated with Part H will mostly be made up of the costs associated with more frequent monitoring. The requirements in Part H need to be enforceable and meet the standard of Reasonably Available Control Technology (RACT). In order to determine RACT, cost is taken into consideration. Most of the costs required by part H were imposed in 2014 when the SIP was last amended for PM2.5.

B) Name and title of department head commenting on the fiscal impacts:

Citation Information

10. This rule change is authorized or mandated by state law, and implements or interprets the following state and federal laws.
    State code or constitution citations (required) (e.g., Section 63G-3-402; Subsection 63G-3-601(3); Article IV) :
    19-2-104

Incorporated Materials

11. This rule adds, updates, or removes the following title of materials incorporated by reference (a copy of materials incorporated by reference must be submitted to DAR; if none, leave blank) :

Official Title of Materials Incorporated (from title page)	Section IX, Control Measures for Area and Point Sources, Part H, Emissions Limits.
Publisher	Utah Division of Air Quality
Date Issued (mm/dd/yyyy)	
Issue, or version (including partial dates)	
ISBN Number	
ISSN Number	
Cost of Incorporated Reference	
Adds, updates, removes	Updates

Comments

12. The public may submit written or oral comments to the agency identified in box 1. (The public may also request a hearing by submitting a written request to the agency. The agency is required to hold a hearing if it receives requests from ten interested persons or from an association having not fewer than ten members. Additionally, the request must be received by the agency not more than 15 days after the publication of this rule in the Utah State Bulletin. See Section 63G-3-302 and Rule R15-1 for more information.)
    A) Comments will be accepted until 5:00 p.m. on (mm/dd/yyyy) : 10/31/2016
    B) A public hearing (optional) will be held:
    On (mm/dd/yyyy): At (hh:mm AM/PM): At (place):

Proposed Effective Date

13. This rule change may become effective on (mm/dd/yyyy): 11/07/2016
    NOTE: The date above is the date on which this rule MAY become effective. It is NOT the effective date. After a minimum of seven days following the date designated in Box 12(A) above, the agency must submit a Notice of Effective Date to the Office of Administrative Rules to make this rule effective. Failure to submit a Notice of Effective Date will result in this rule lapsing and will require the agency to start the rulemaking process over.

Indexing Information

14. Indexing information - keywords (maximum of four, one term per field, in lower case, except for acronyms (e.g., "GRAMA") or proper nouns (e.g., "Medicaid")):
air pollution, PM10, ozone, PM2.5

File Information

15. Attach an RTF document containing the text of this rule change (filename):
No document is associated with this filing.

To the Agency

Information requested on this form is required by Sections 63G-3-301, 302, 303, and 402. Incomplete forms will be returned to the agency for completion, possibly delaying publication in the Utah State Bulletin, and delaying the first possible effective date.

Agency Authorization

Agency head or designee, and title:	Bryce Bird Director	Date (mm/dd/yyyy): 09/06/2016

ITEM 10

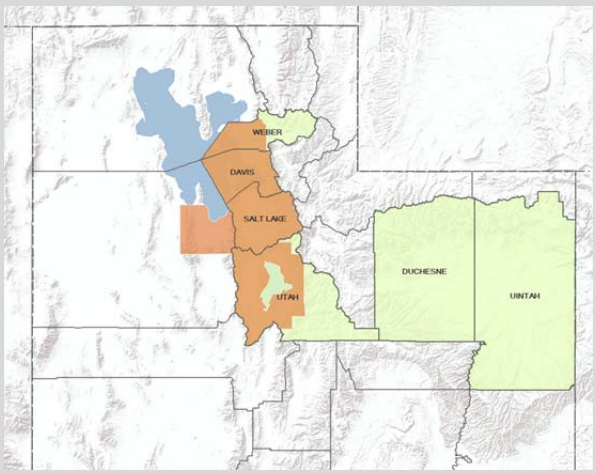
STAFF REVIEW FOR UTAH'S OZONE DESIGNATION

Overview

- On October 1, 2015, EPA strengthened the ozone standard from 75 parts per billion (ppb) to 70 ppb. The 70 ppb standard is calculated as the fourth-highest daily maximum, averaged across three consecutive years.
- The governor will submit an area designation recommendation to the EPA by October 1, 2016. The areas designated nonattainment must include places that exceed the current 70 ppb standard and areas that contribute to exceedances of the standard.
- Salt Lake, Davis, Weber, Utah, Duchesne, and Uintah counties have three-year design values that exceed the 70 ppb standard (green on map at right).
- The Division of Air Quality evaluated the counties that exceed the standard and adjacent areas using five criteria to determine the most appropriate nonattainment area recommendations.
  - Air Quality Data
  - Emissions & Emissions Related Data
  - Geography & Topography
  - Meteorology
  - Jurisdictional Boundaries

Counties of Utah where monitored ozone exceeds the 70 ppb design value (green)

Wasatch Front Area Designation Review (orange)



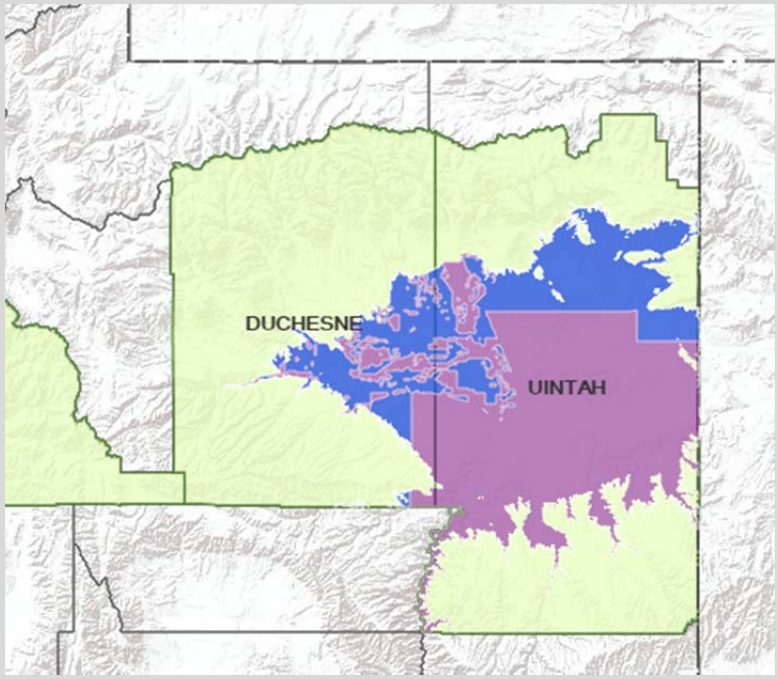
Wasatch Front

- We are required to consider counties adjacent to the violating counties that are part of the Core Based Statistical Area. This captures Box Elder, Morgan, Summit, Wasatch, Tooele, and Juab counties.
- Low emissions combined with the topography of the Wasatch Mountains led to the conclusion that Morgan and Wasatch counties and portions of Weber and Utah counties do not contribute to ozone on the Wasatch Front. Juab, Box Elder, and parts of Tooele were also excluded based on low emissions from those counties.
- A combination of topography and meteorology indicates that Summit County does not contribute to ozone exceedances on the Wasatch Front and should be excluded from the designation.
- Based on staff's review of the five criteria above, the ozone nonattainment area on the Wasatch Front should include all of Salt Lake and Davis counties, Weber and Utah counties west of the Wasatch Front, and a part of Tooele County that includes Tooele (orange on map above).
- The Wasatch Front nonattainment area classification will likely be marginal.

Uinta Basin

- Meteorology and topography are the driving factors for high ozone events in the Uinta Basin. The high ozone events occur in the winter months when there is snow on the ground and a cold temperature inversion traps the ozone precursor emissions, NOx and VOCs, in the Basin. The sun reflecting off the snow creates needed energy for ozone formation.
- Complex jurisdictional issues in the Basin complicate air quality regulation. State lands are intermixed with the Uintah and Ouray Indian Reservation and Indian Country lands. Ouray is the regulatory monitor that drives the designation because it has the highest monitored values in the region. Though State monitors at Vernal and Roosevelt have measured exceedances of the new ozone standard, they are not as high nor occur as frequently.
- Based on the unique nature of the Uinta Basin ozone events and extensive studies of the area, staff 's review shows that the ozone nonattainment area could begin at a maximum elevation of 6,000 feet following the topography of the Basin combined with Duchesne and Uintah county boundaries (blue on map below). This review excludes the Uintah and Ouray Indian Reservation and Indian Country lands that are within the 6,000-foot boundary (purple on the map below).
- The Uinta Basin designation could be Marginal or Moderate Nonattainment.

Uinta Basin Area Designation Review (blue)



Air Toxics Compliance Monitoring

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-519-16

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: August 1, 2016

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – July 2016

Asbestos Demolition/Renovation NESHAP Inspections	28
Asbestos AHERA Inspections	42
Asbestos State Rules Only Inspections	4
Asbestos Notifications Accepted	200
Asbestos Telephone Calls Answered	444
Asbestos Individuals Certifications Approved/Disapproved	23/0
Asbestos Company Certifications/Re-Certifications	2/2
Asbestos Alternate Work Practices Approved/Disapproved	14/0
Lead-Based Paint (LBP) Inspections	12
LBP Notifications Approved	0
LBP Telephone Calls Answered	13
LBP Letters Prepared and Mailed	0
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	3
LBP Individual Certifications Approved/Disapproved	10/0
LBP Firm Certifications	11

Notices of Violation Issued	0
Compliance Advisories Issued	10
Warning Letters Issued	9
Settlement Agreements Finalized	1
Penalties Agreed to:	
#1 Lead Safety of Utah	$218.75

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-1194-16

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: August 16, 2016

SUBJECT: Compliance Activities – July 2016

Annual Inspections Conducted:

Major 6
Synthetic Minor 1
Minor 27

On-Site Stack Test Audits Conducted: 1

Stack Test Report Reviews: 55

On-Site CEM Audits Conducted: 1

Emission Reports Reviewed: 18

Temporary Relocation Requests Reviewed & Approved: 6

Fugitive Dust Control Plans Reviewed & Accepted: 97

Soil Remediation Report Reviews: 0

[1]Miscellaneous Inspections Conducted: 36

Complaints Received: 33

Breakdown Reports Received: 0

195 North 1950 West • Salt Lake City, Utah
Mailing Address: P.O. Box 144820 • Salt Lake City, Utah 84114-4820
Telephone (801) 536-4000 • Fax (801)536-4099 • T.D.D. (801) 903-3978
www.deq.utah.gov
Printed on 100% recycled paper

Compliance Actions Resulting From a Breakdown..... 0

Warning Letters Issued: 3

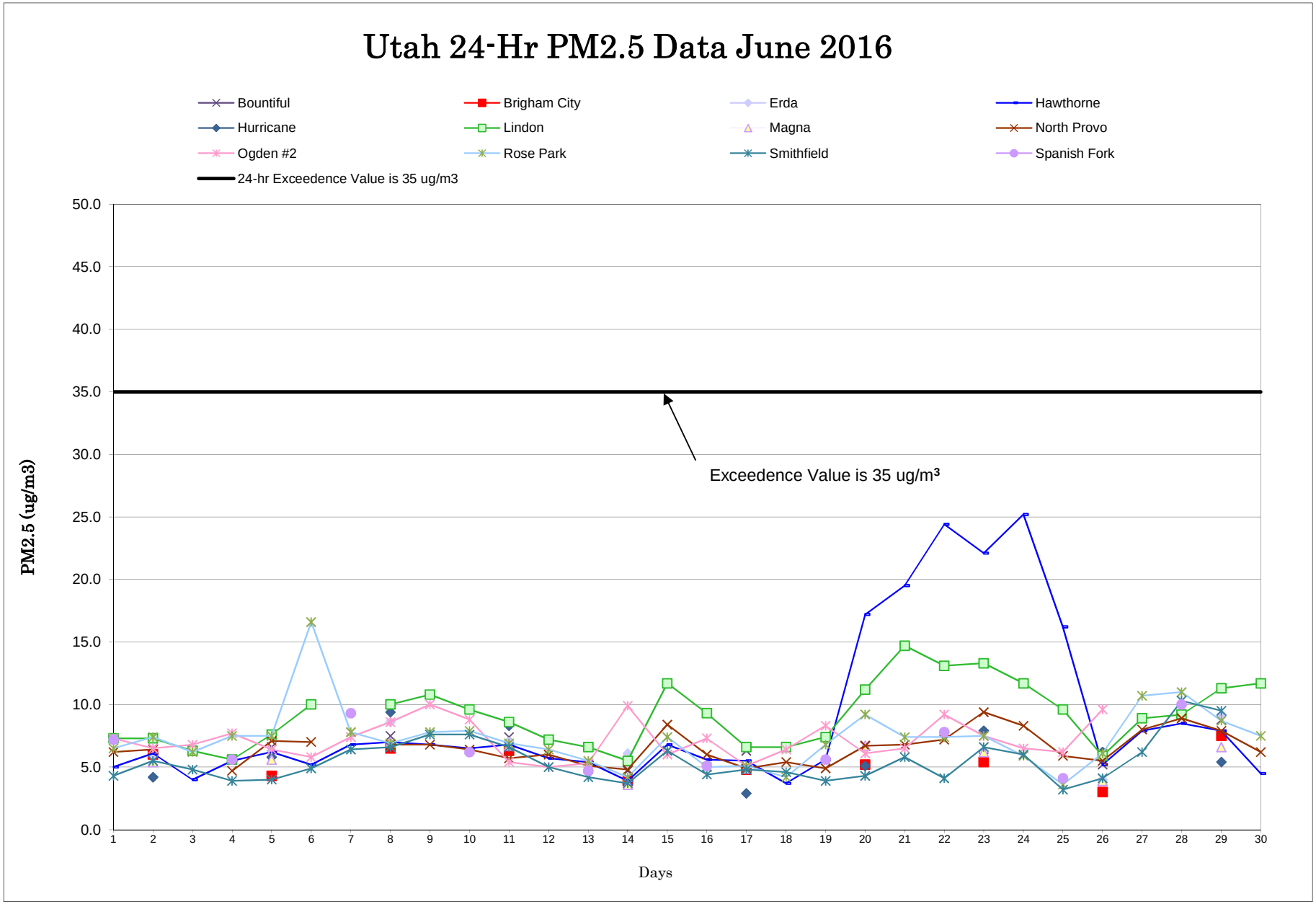
Notices of Violation Issued:..... 0

Compliance Advisories Issued:..... 2

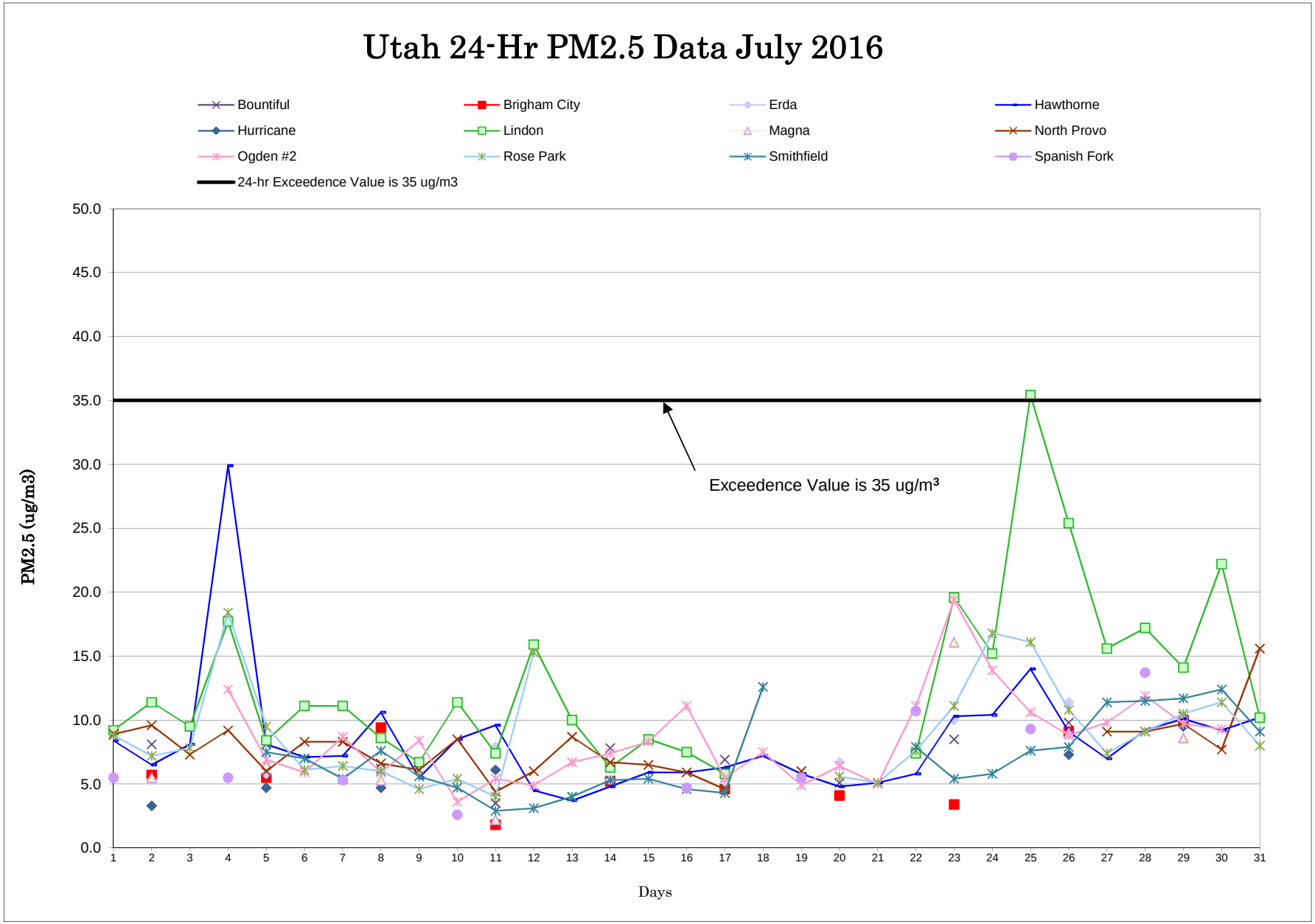
Settlement Agreements Reached: 3

Houwelling Utah Property, Inc..... $583.00
MACA Supply..... $239.00
TTM Technologies..... $359.00

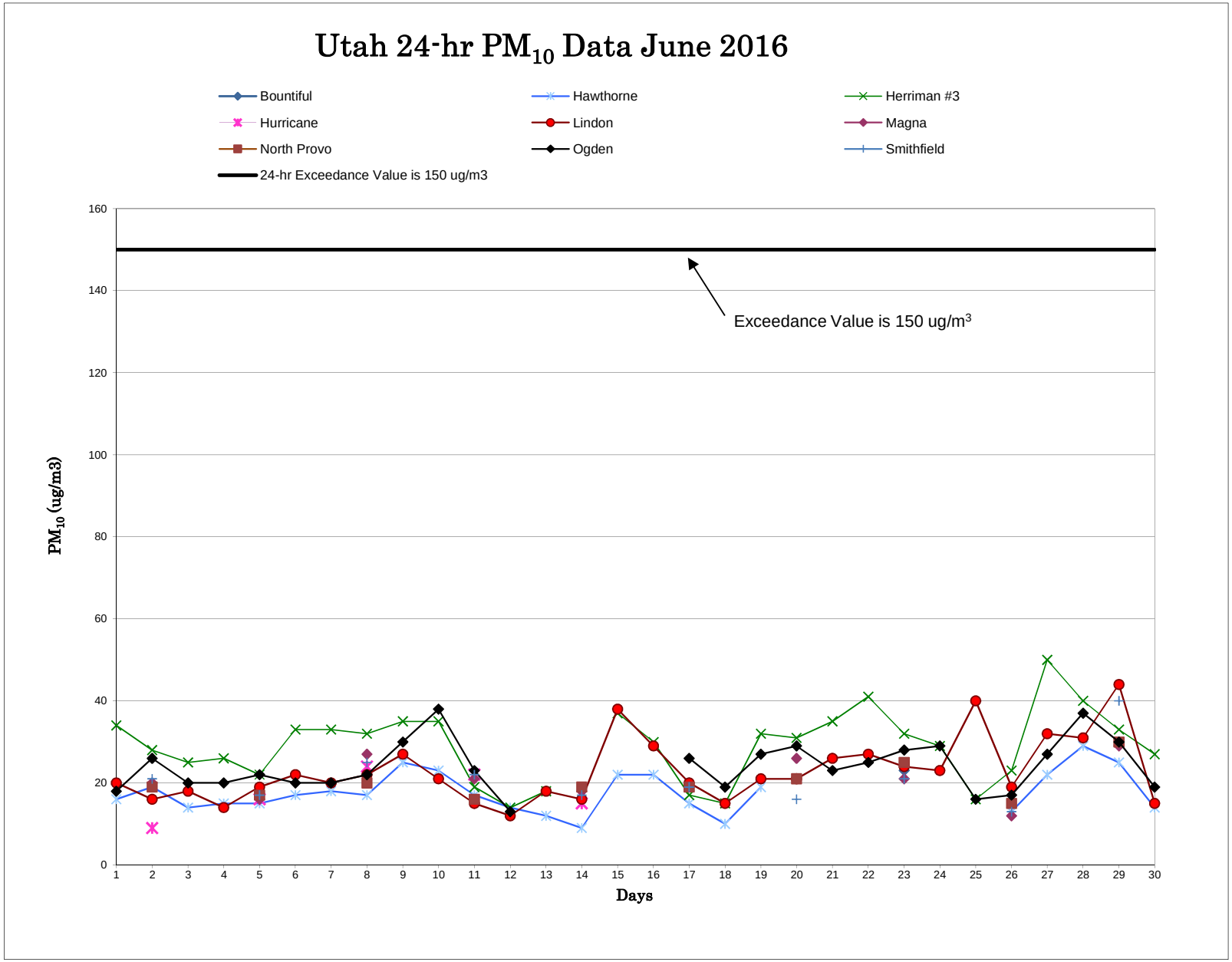
[1]Miscellaneous inspections include, e.g., surveillance, level I inspections, VOC inspections, complaints, on-site training, dust patrol, smoke patrol, open burning, etc.

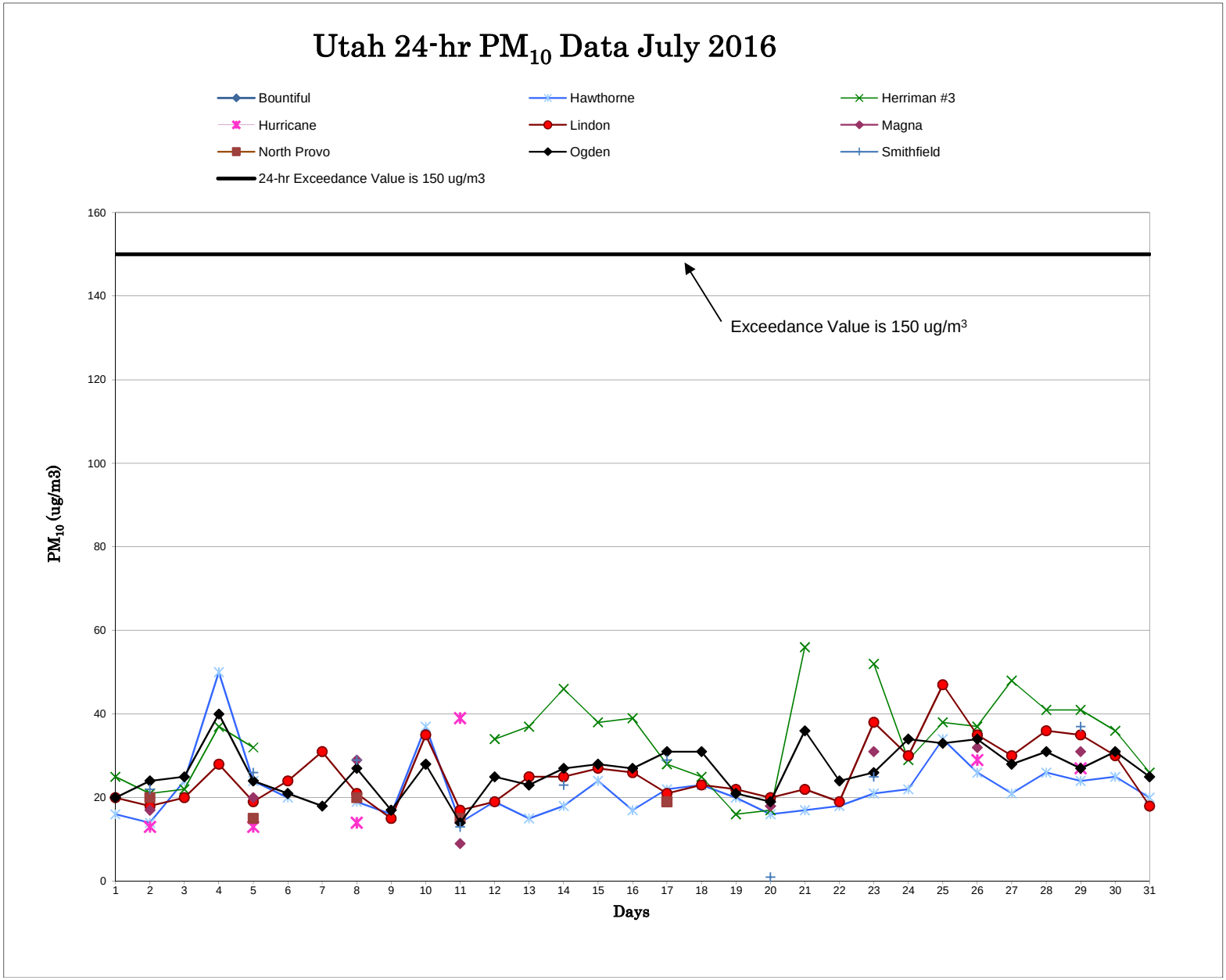


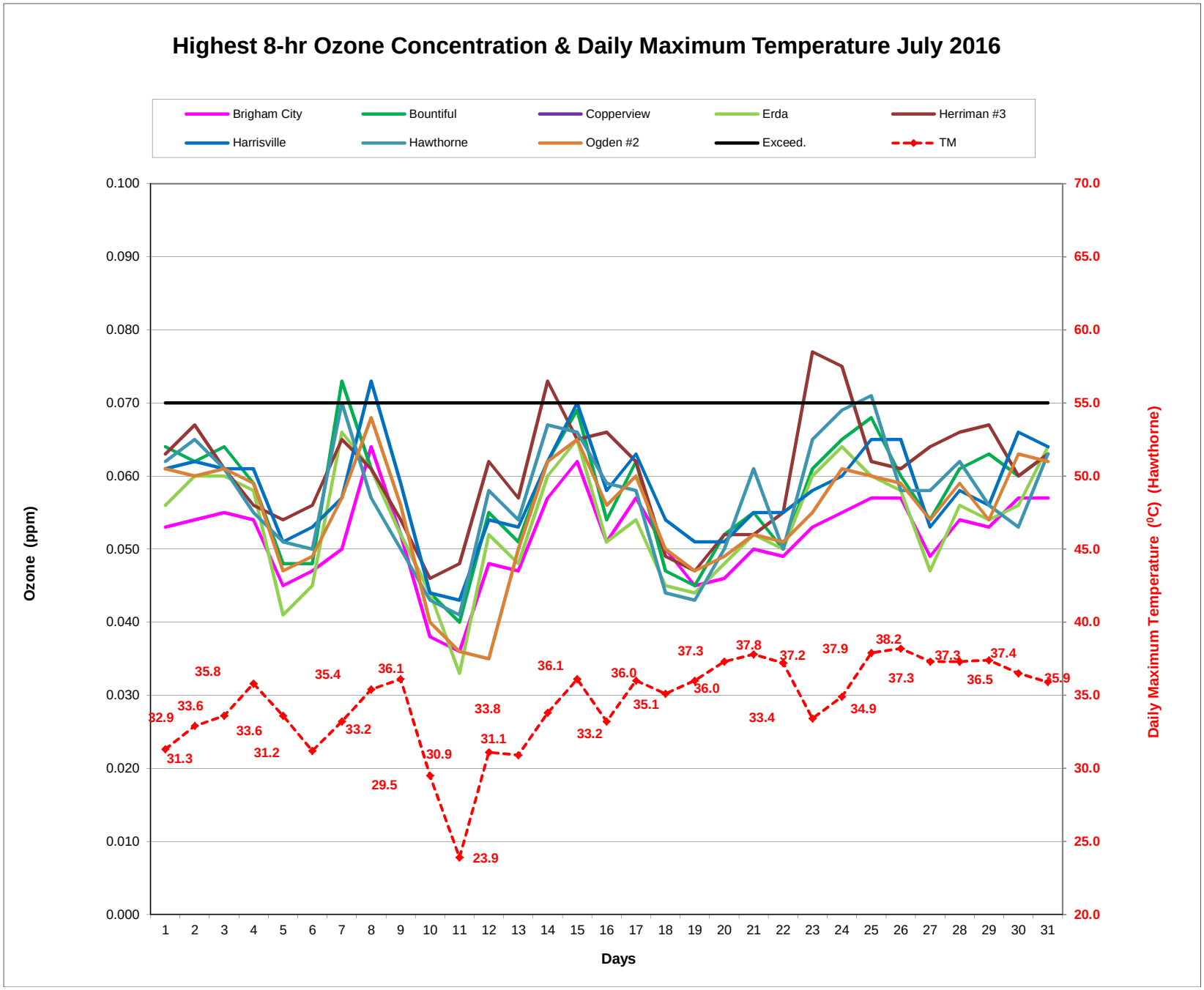
Utah Division of Air Quality

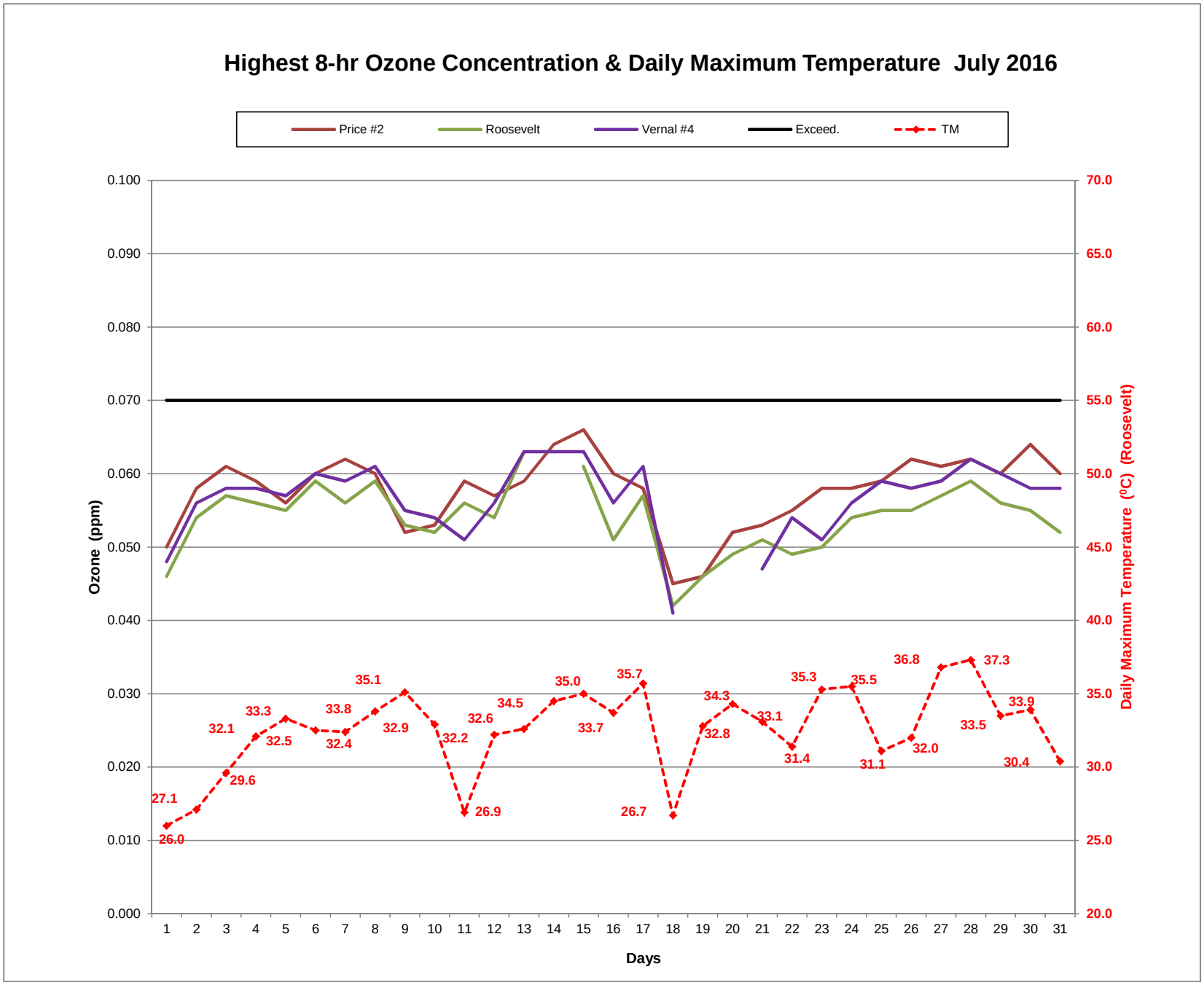


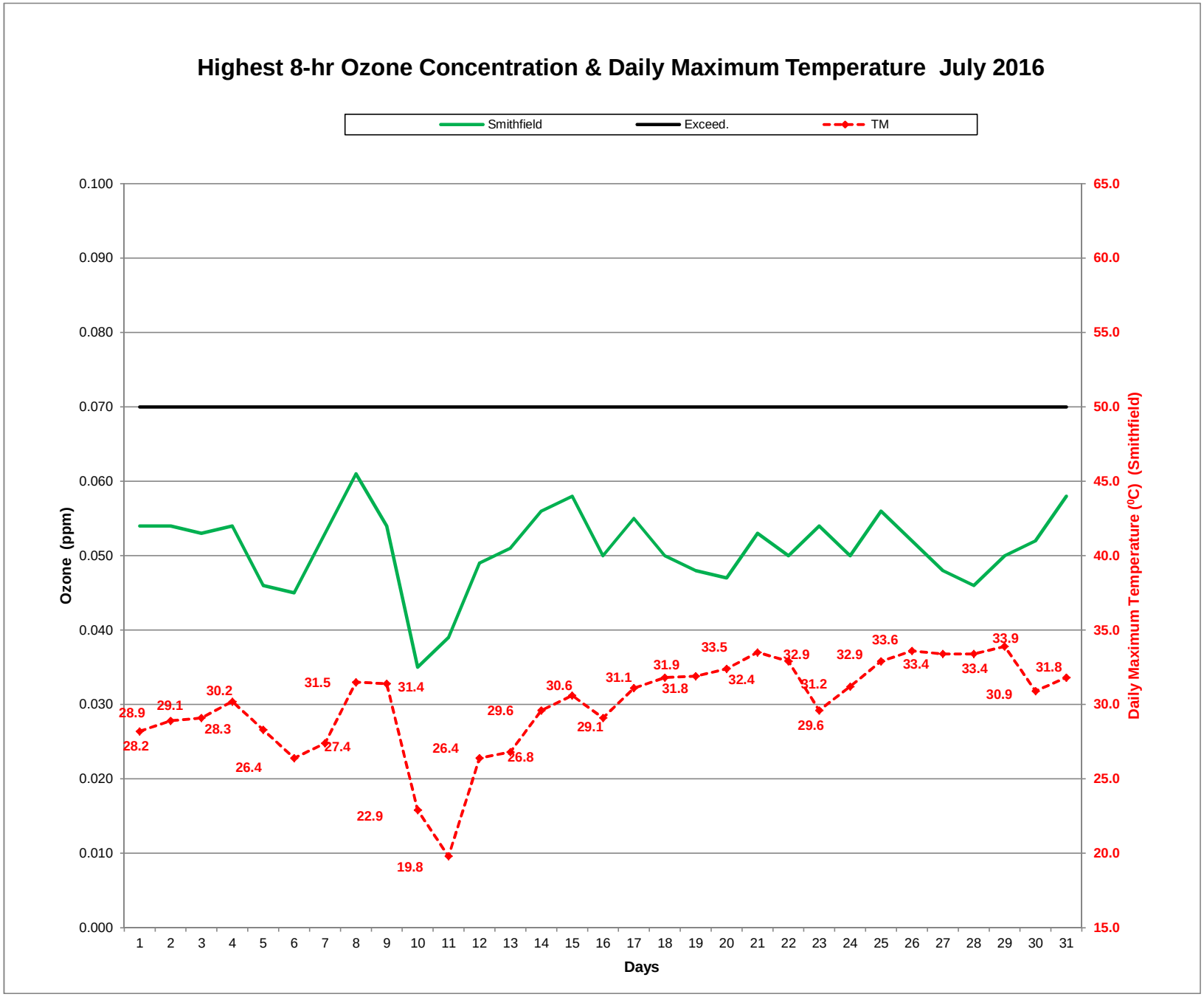
Utah Division of Air Quality

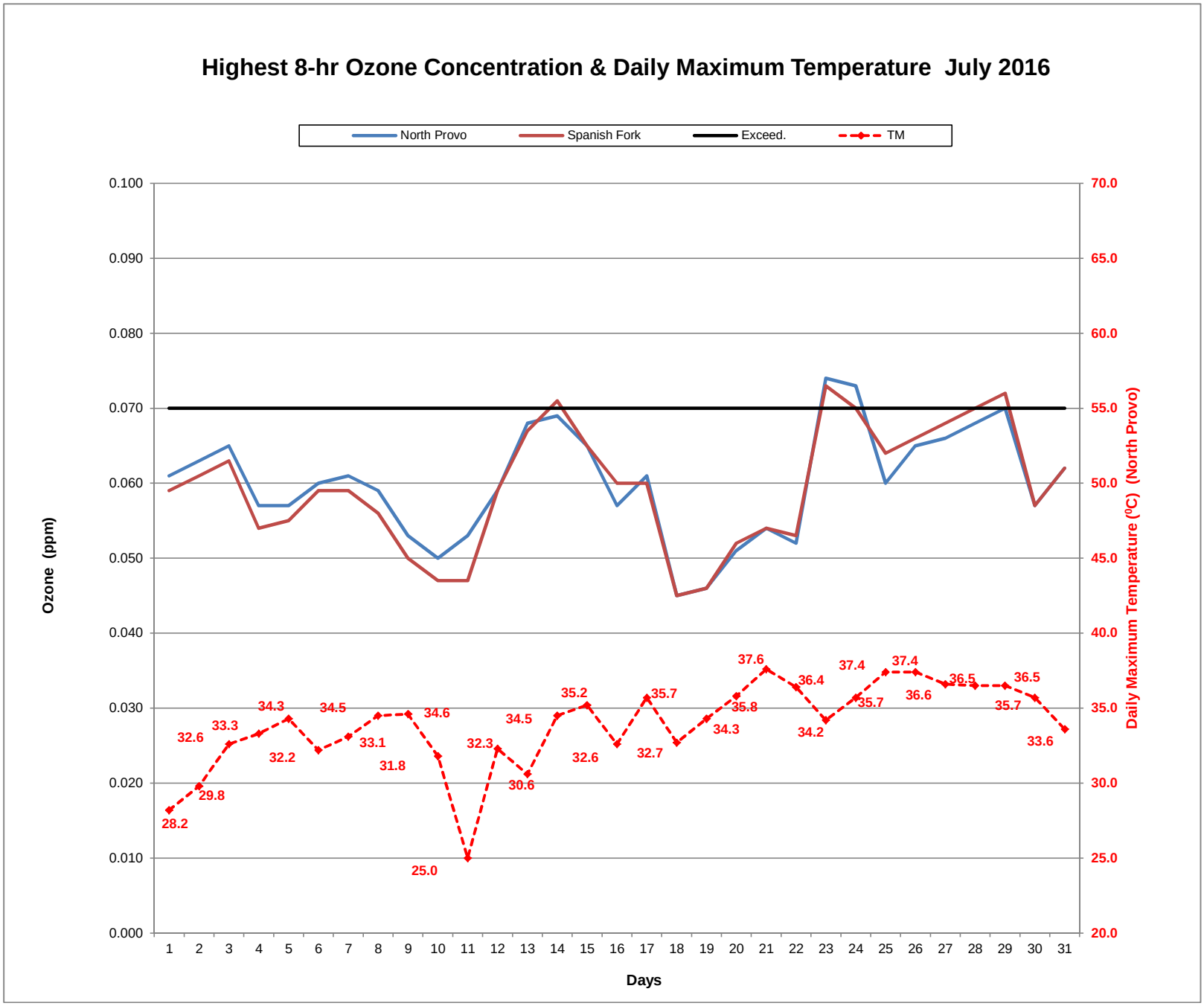

Utah 24-hr PM10 Data June 2016
Bountiful
Hawthorne
Herriman #3
Hurricane
Lindon
Magna
North Provo
Ogden
Smithfield
24-hr Exceedance Value is 150 ug/m3
Exceedance Value is 150 ug/m3
PM10 (ug/m3)
Days
0
20
40
60
80
100
120
140
160
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30


Utah 24-hr PM10 Data July 2016
Bountiful
Hawthorne
Herriman #3
Hurricane
Lindon
Magna
North Provo
Ogden
Smithfield
24-hr Exceedance Value is 150 ug/m3
Exceedance Value is 150 ug/m3
PM10 (ug/m3)
Days
0
20
40
60
80
100
120
140
160
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31


Highest 8-hr Ozone Concentration & Daily Maximum Temperature July 2016
Brigham City
Bountiful
Copperview
Erda
Herriman #3
Harrisville
Hawthorne
Ogden #2
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Hawthorne)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
32.9
33.6
35.8
33.6
35.4
36.1
30.9
23.9
33.8
36.1
36.0
35.1
36.0
37.3
37.8
37.2
37.9
38.2
37.3
37.4
35.9
31.3
31.2
33.2
29.5
31.1
33.2
33.4
34.9
37.3
36.5


Highest 8-hr Ozone Concentration & Daily Maximum Temperature July 2016
Price #2
Roosevelt
Vernal #4
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Roosevelt)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
26.0
27.1
29.6
32.1
32.5
33.3
32.4
33.8
35.1
32.9
32.2
26.9
32.6
34.5
35.0
33.7
35.7
26.7
32.8
34.3
33.1
31.4
35.3
35.5
31.1
32.0
36.8
33.5
37.3
33.9
30.4


Highest 8-hr Ozone Concentration & Daily Maximum Temperature July 2016
Smithfield
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (⁰C) (Smithfield)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
28.2 28.9 29.1 28.3 30.2 26.4 27.4 31.5 22.9 31.4 19.8 26.4 26.8 29.6 30.6 29.1 31.1 31.8 31.9 33.5 32.4 32.9 31.2 29.6 32.9 33.6 33.4 33.4 33.9 30.9 31.8


Highest 8-hr Ozone Concentration & Daily Maximum Temperature July 2016
North Provo
Spanish Fork
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (North Provo)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
28.2
29.8
32.6
33.3
32.2
34.3
34.5
33.1
31.8
34.6
25.0
32.3
30.6
34.5
35.2
32.6
35.7
32.7
34.3
35.8
37.6
34.2
36.4
37.4
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37.4
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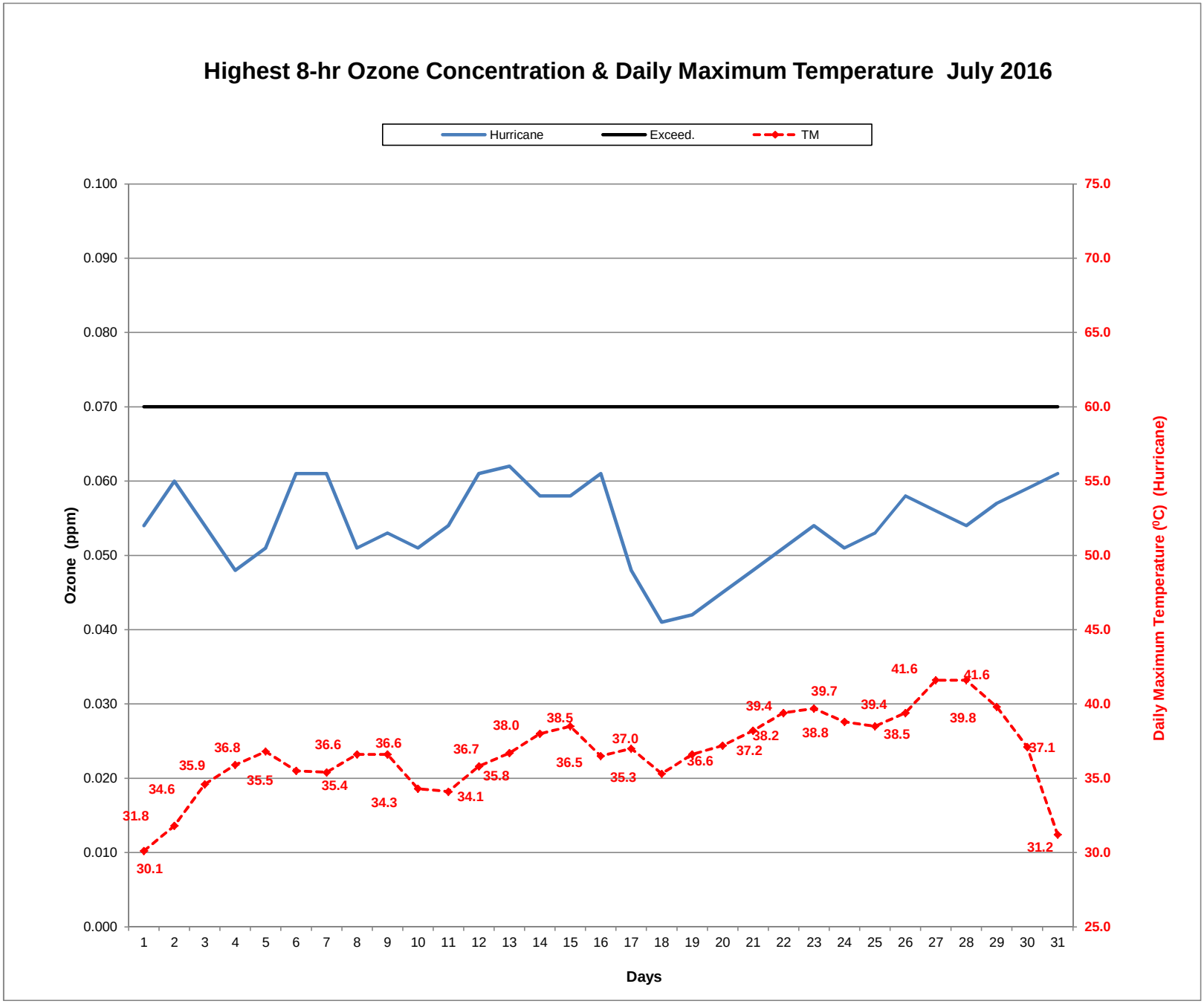
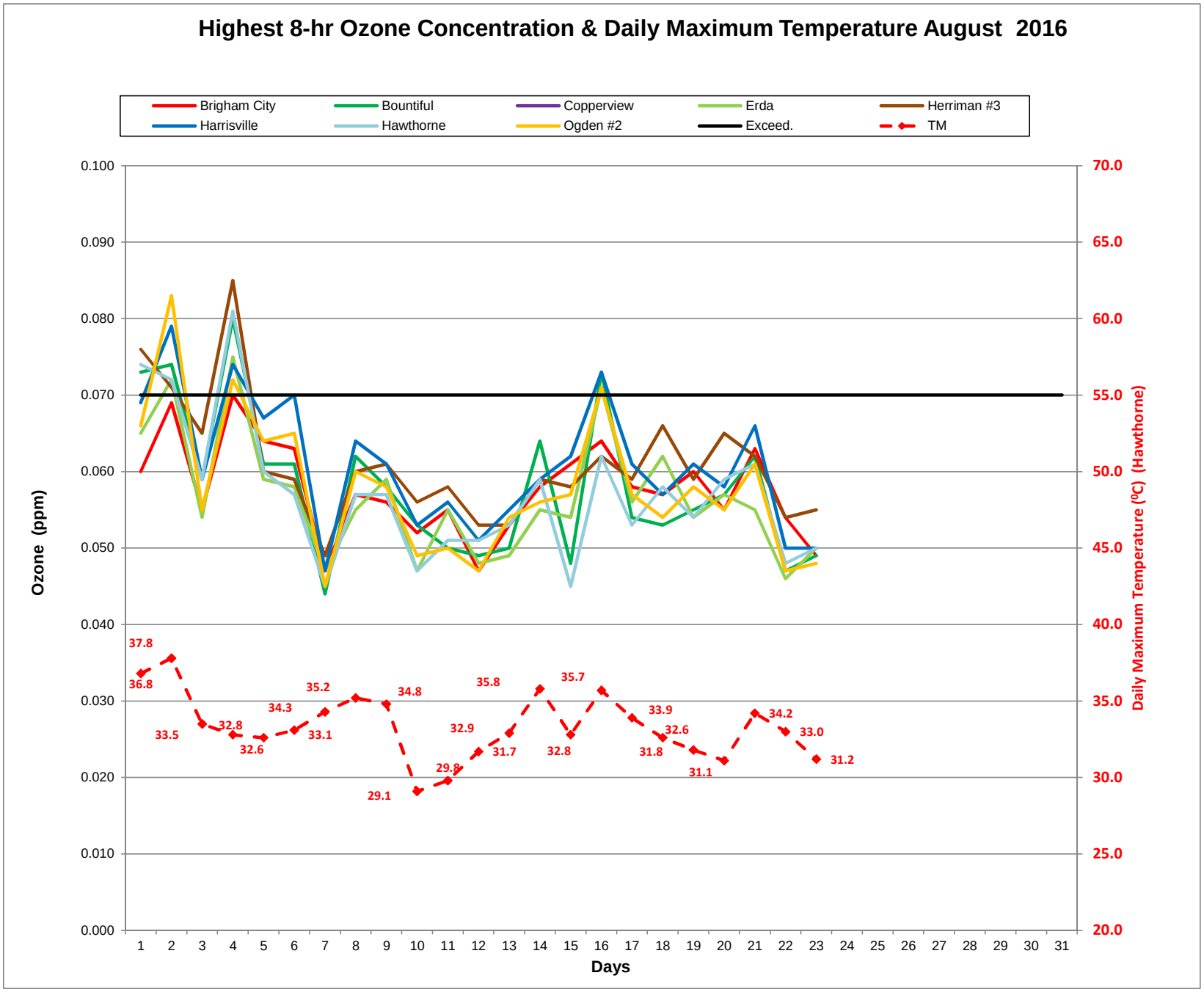
36.5
35.7
36.5
33.6


Highest 8-hr Ozone Concentration & Daily Maximum Temperature July 2016
Hurricane
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (⁰C) (Hurricane)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
75.0
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
30.1
31.8
34.6
35.9
36.8
35.5
35.4
36.6
36.6
34.3
34.1
36.7
35.8
38.0
38.5
36.5
35.3
37.0
36.6
37.2
38.2
39.4
38.8
39.7
39.4
38.5
41.6
39.8
41.6
37.1
31.2


Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2016
Brigham City
Bountiful
Copperview
Erda
Herriman #3
Harrisville
Hawthorne
Ogden #2
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (0C) (Hawthorne)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
37.8
36.8
33.5
32.8
32.6
34.3
35.2
33.1
34.8
29.1
29.8
32.9
35.8
31.7
35.7
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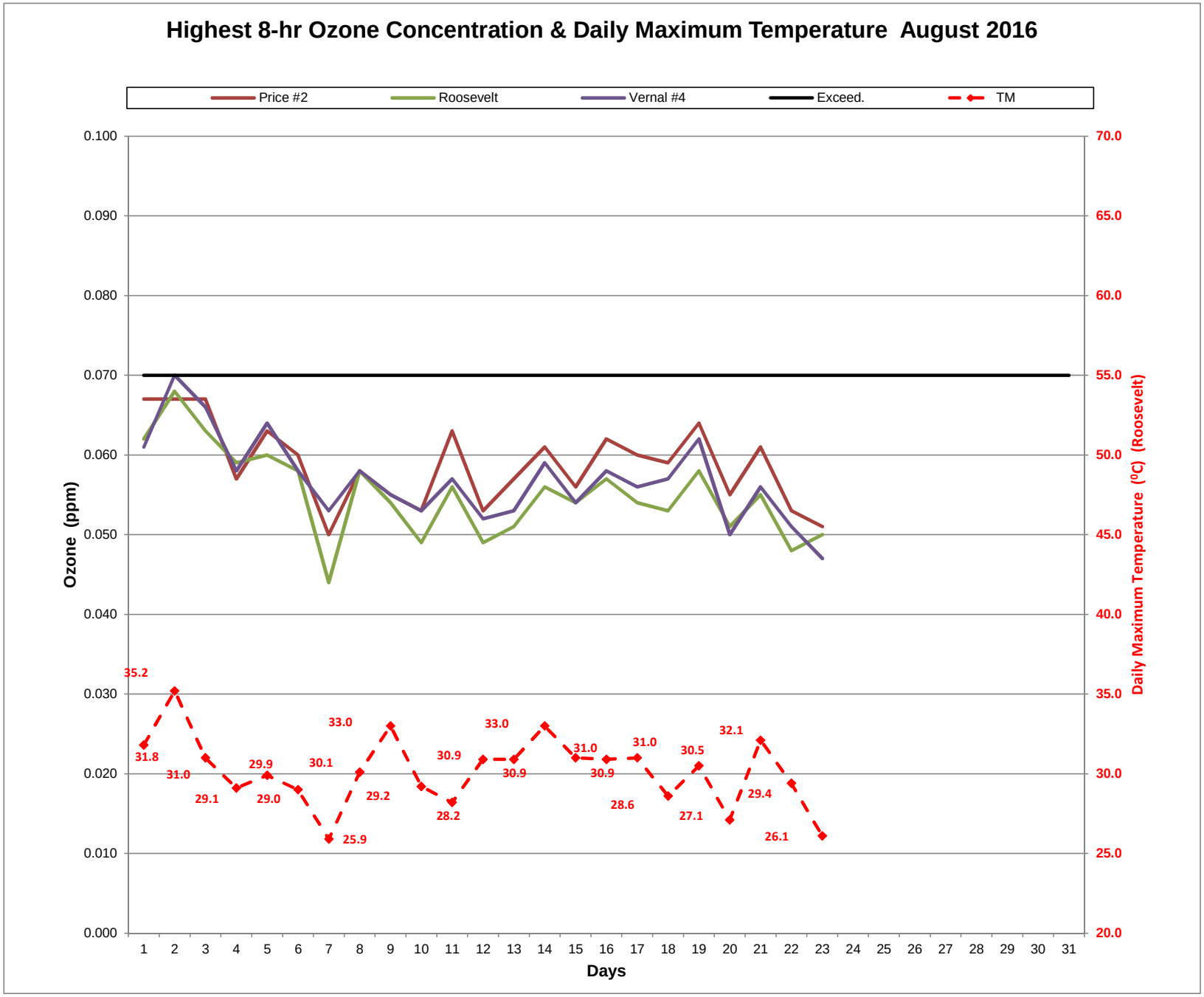
33.9
32.6
31.8
31.1
34.2
33.0
31.2


Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2016
Price #2
Roosevelt
Vernal #4
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (Roosevelt)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
35.2
31.8
31.0
29.1
29.9
29.0
30.1
25.9
33.0
29.2
30.9
28.2
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31.0
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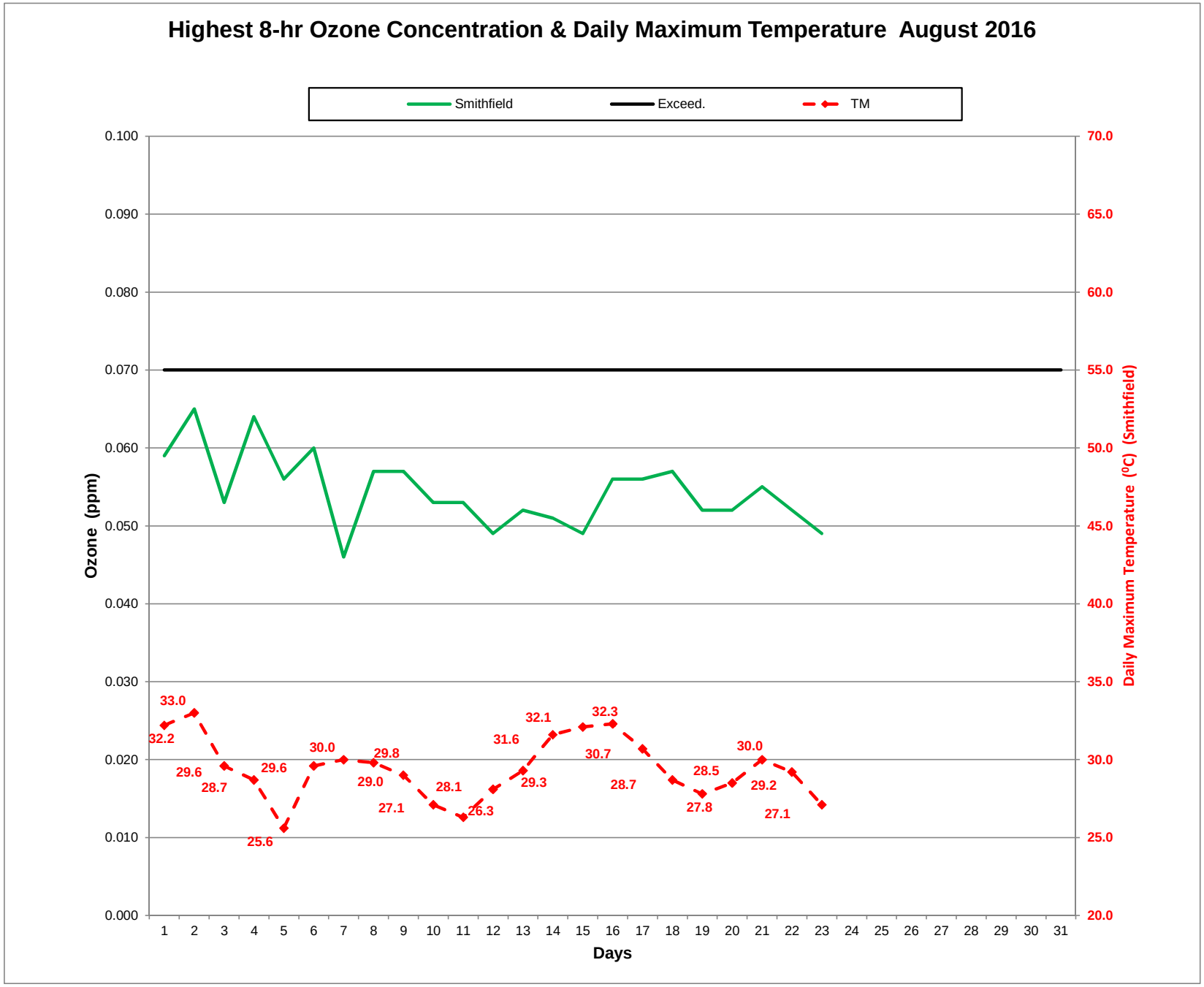
30.5
27.1
32.1
29.4
26.1


Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2016
Smithfield
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (Smithfield)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
32.2
33.0
29.6
28.7
25.6
29.6
30.0
29.0
29.8
27.1
28.1
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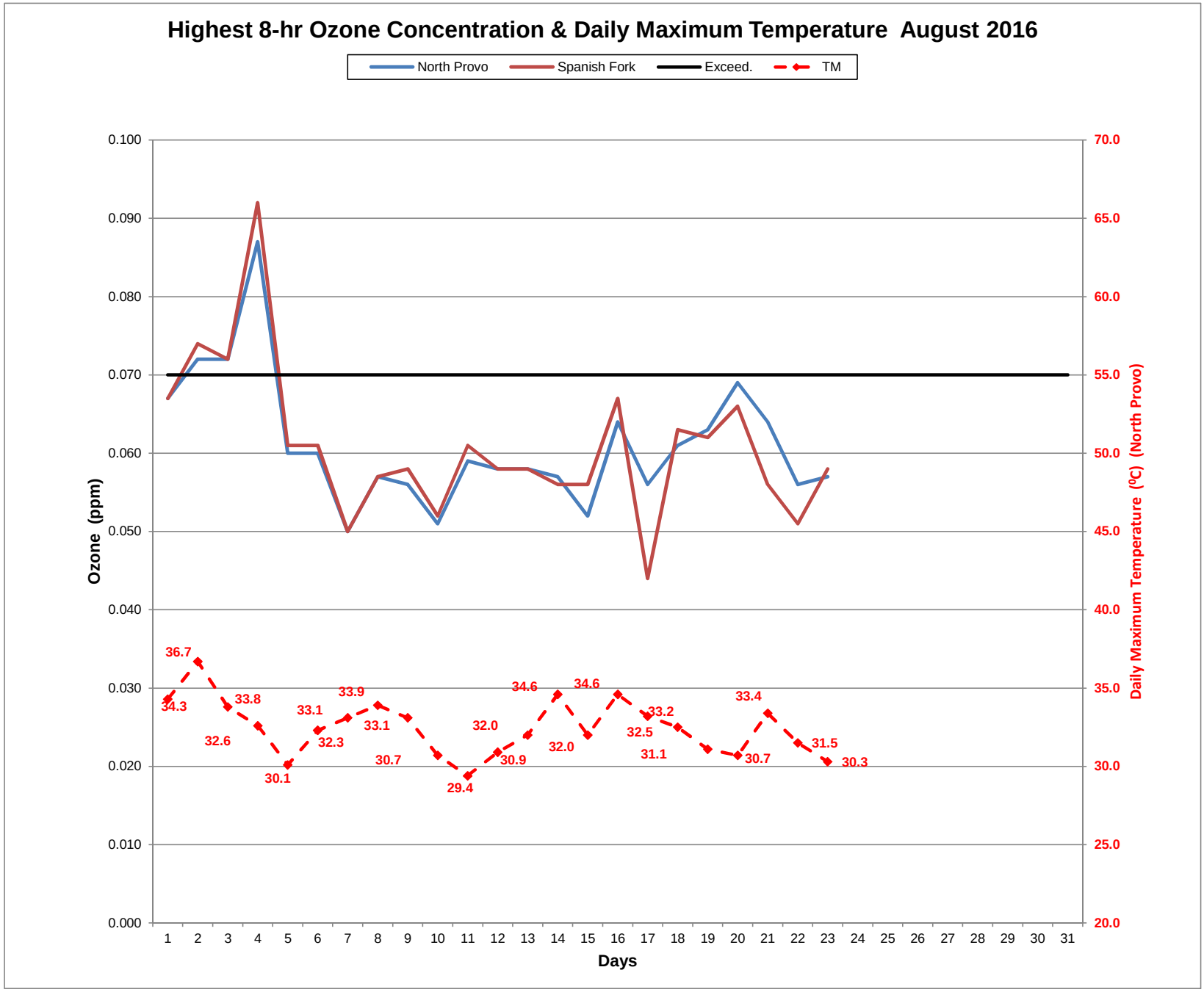
29.2
27.1


Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2016
North Provo
Spanish Fork
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (North Provo)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
34.3
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33.9
33.1
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29.4
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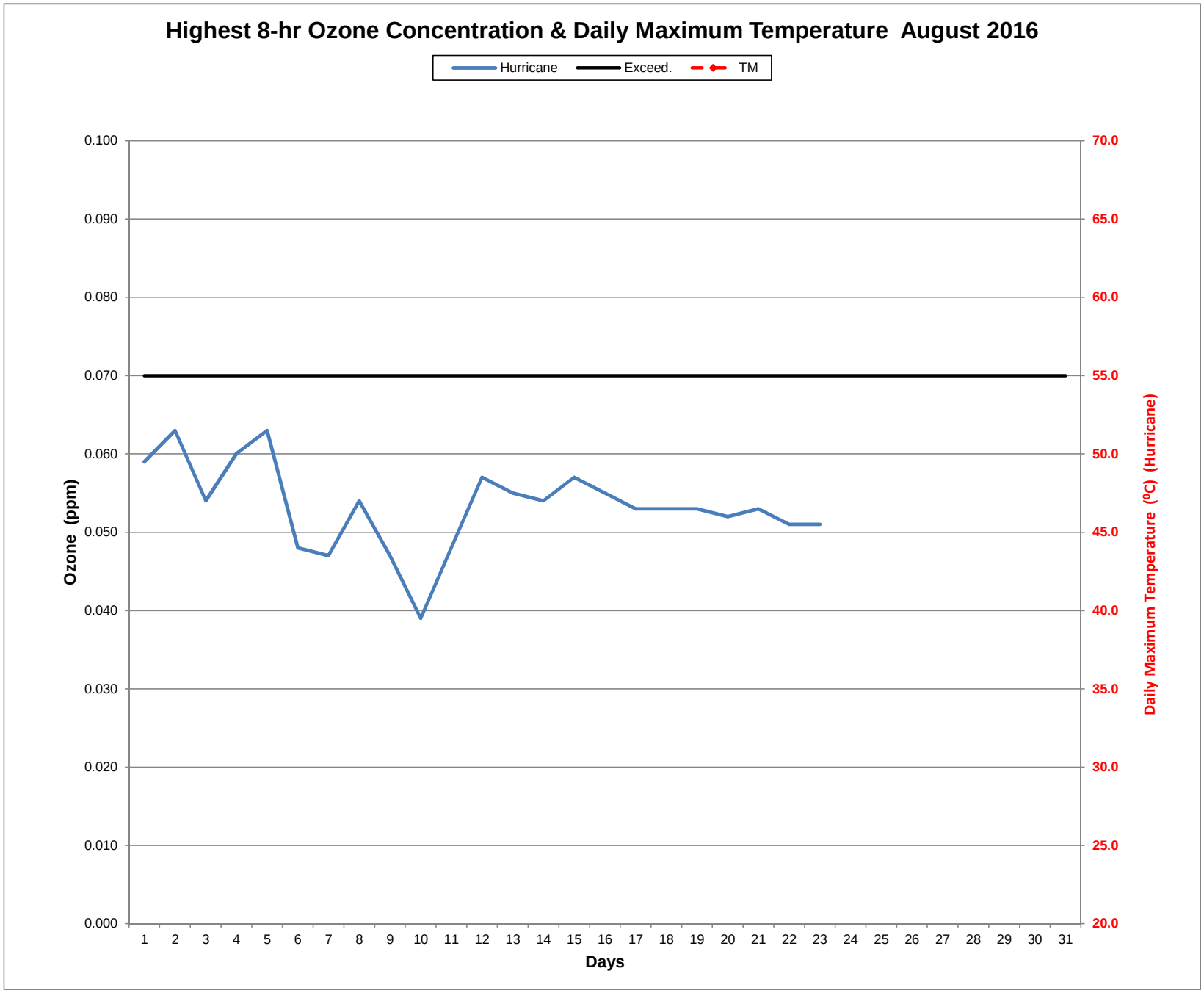
Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2016
Hurricane
Exceed.
TM
Ozone (ppm)
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
Daily Maximum Temperature (°C) (Hurricane)
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Days