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-051-15

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 21, 2015

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Repeal Existing SIP Subsections IX. Part H. 1, 2, 3, and 4 and Re-enact with SIP Subsections IX. Part H. 1, 2, 3, and 4: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM_{10} Requirements.

Introduction:

This item supports a proposed maintenance plan for Utah's three PM_{10} nonattainment areas, Salt Lake County, Utah County, and Ogden City.

The existing State Implementation Plan (SIP) for PM_{10}, affecting Salt Lake and Utah Counties, was adopted in 1991 and included numerous controls on specific stationary sources of PM_{10}, SO_2 and NOx. Emission limits reflecting controls at these sources were included in the SIP, thus making them federally enforceable.

SIP limits affecting Utah County were revised in 2002, and effectively approved into the SIP by EPA in 2003.

As part of this maintenance plan, the list of stationary sources to be included in the SIP was reconsidered, particularly as it applies to Salt Lake County. Criteria were established to include sources located in any of the nonattainment areas with actual emissions (in 2011), or with potentials to emit, that are at least 100 tons per year for PM_{10}, SO_2, or NOx.

Using these criteria means that some sources will not be retained in the revised Part H, while other new sources, that did not exist when the original SIP was written, will be added.

There are no SIP sources in the Ogden City nonattainment area.

Contingency Measures:

The maintenance plan, if approved, will allow Utah to request that EPA redesignate these areas back to attainment for PM_{10}. The Clean Air Act requires, under Section 175A(d), that any such plan revision must contain contingency provisions to assure the State will promptly correct any violation of the standard which occurs after the redesignation of the area. Furthermore, these provisions must include a requirement that the State will implement all measures which were contained in the SIP for the area prior to redesignation.

As discussed above, some of the stationary sources that had appeared in the existing SIP did not meet the emissions criteria, and therefore were not retained in this revised Part H.

Certain emission limits for these sources may be candidates for these contingency provisions should the respective areas be redesignated and should there be a subsequent violation of the PM_{10} standard. Because of the 2002 SIP revision for Utah County, this affects only sources that had been listed in the Salt Lake County portion of the SIP. As such, these sources and their respective SIP conditions from the existing SIP have been identified in section (10) of the maintenance plan proposed for SIP Section IX.A.10. There were no SIP sources in the Ogden City nonattainment area.

SIP Organization:

As originally written in 1991, the PM_{10} nonattainment SIP for Salt Lake and Utah Counties included an Appendix A wherein the emission limits for specific stationary sources were included in the SIP. This Appendix A was later reorganized as SIP Section IX Part H.

In 2005, Utah prepared a revision to the PM_{10} plan that showed continued attainment through the year 2017. This revision, also structured as a maintenance plan, included the changes to Part H that gave it its present form. The PM_{10} provisions of Part H are contained in subsections 1 – 4, while the $PM_{2.5}$ provisions are contained in subsections 11, 12, and 13.

As presently structured, subsections 1 – 3 contain:

- H.1. – General Requirements that apply to all listed sources
- H.2. – Source-Specific Limitations in Salt Lake and Davis Counties
- H.3. – Source-Specific Limitations in Utah County

As proposed, the focus of these three subsections will remain the same.

Existing subsection H.4, “Establishment of Alternative Requirements,” is not part of the proposal. Rather, H.4 is being re-purposed to include “Interim Emission Limits and Operating Practices.”

These interim limits are intended to cover sources that are phasing-in control measures implemented as part of the $PM_{2.5}$ SIP. The end of the phase-in period will be January 1, 2019. As the control technology at these sources becomes operational, these interim limits will be superseded by the limits appearing in subsections H 1 – 3.

Staff Recommendation: Staff recommends that the Board propose for public comment to repeal existing SIP Subsections IX Part H 1, 2, 3, and 4 and re-enact with SIP Subsections IX Part H 1, 2, 3, and 4: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM_{10} Requirements, as proposed.

H.1 General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM10 Requirements

a. Except as otherwise outlined in individual conditions of this Subsection IX.H.1 listed below, the terms and conditions of this Subsection IX.H.1 shall apply to all sources subsequently addressed in Subsection IX.H.2 and IX.H.3. Should any inconsistencies exist between these two subsections, the source specific conditions listed in IX.H.2 and IX.H.3 shall take precedence.

b. The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.

c. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request, and shall include a period of two years ending with the date of the request.

d. All emission limitations listed in Subsections IX.H.2 and IX.H.3 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.2 and IX.H.3.

e. Stack Testing.

i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.2 and I.X.H.3 shall be performed in accordance with the following:

A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved methods acceptable to the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or other EPA-approved testing methods acceptable to the Director.

C. 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.

D. SO2: 40 CFR 60 Appendix A, Method 6C or other EPA-approved testing methods acceptable to the Director.

E. NOx: 40 CFR 60 Appendix A, Method 7E or other EPA-approved testing methods acceptable to the Director.

F. 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.

G. 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. 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.

H. 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 (FCCU)

A. FCCU SO2 Emissions

I. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an SO2 emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.

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

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) or 40 C.F.R. §60.104a(d) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests once every three (3) 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 from the FCCU for determination of source-wide PM10 emissions.

ii. Limits on Refinery Fuel Gas.

A. All petroleum refineries in or affecting any PM2.5 nonattainment area or any PM10 nonattainment or maintenance area shall reduce the H2S 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. Sulfur Removal Units

A. All petroleum refineries in or affecting any PM10 nonattainment or maintenance area shall require:

I. Sulfur removal units/plants (SRUs) that are at least 95% effective in removing sulfur from the streams fed to the unit; or

II. SRUs that meet the SO2 emission limitations listed in 40 CFR 60.102a(f)(1) or 60.102a(f)(2) as appropriate.

B. The amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).

C. Compliance shall be demonstrated by daily monitoring of flows to the SRU(s). Continuous monitoring of SO2 concentration in the exhaust stream shall be conducted via CEM as outlined in IX.H.1.f above. Compliance shall be determined on a rolling 30-day average.

iv. No Burning of Liquid Fuel Oil in Stationary Sources

A. No petroleum refineries in or affecting any PM10 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.1.g.iv.A above.

v. Requirements on Hydrocarbon Flares.

A. Beginning January 1, 2018, all hydrocarbon flares at petroleum refineries located in or affecting a designated PM10 nonattainment 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 Subpart Ja.

B. By no later than January 1, 2019, all major source petroleum refineries in or affecting a designated PM10 nonattainment area within the State shall install and operate a flare gas recovery system or equivalent flare gas minimization process(es) designed to limit hydrocarbon flaring from each affected flare to levels below the values listed in 40 CFR 60.103a(c), except during periods when one or more process units, connected to the affected flare, are undergoing startup, shutdown or experiencing malfunction. Flare gas recovery is not required for dedicated SRU flare and header systems, or HF flare and header systems.

H.2 Source Specific Emission Limitations in Salt Lake County PM10 Nonattainment/Maintenance Area

a. Big West Oil Company

i. Source-wide PM10 Cap

By no later than January 1, 2019, combined emissions of PM10 shall not exceed 1.037 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.a.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM10: 1.9 lb/MMscf
Condensable PM10: 5.7 lb/MMscf

Plant gas:
Filterable PM10: 1.9 lb/MMscf
Condensable PM10: 5.7 lb/MMscf

Fuel Oil: The PM10 emission factor shall be determined from the latest edition of AP-42

Cooling Towers: The PM10 emission factor shall be determined from the latest edition of AP-42

FCC Stacks: The PM10 emission factor shall be established by stack test.

B. The default emission factors listed in IX.H.2.a.i.A above apply until such time as stack testing is conducted as outlined below:

PM10 stack testing on the FCC shall be conducted at least once every three (3) years. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM10 Cap shall be determined for each day as follows:

Total 24-hour PM10 emissions for the emission points shall be calculated by adding the daily results of the PM10 emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, and the FCCs to arrive at a combined daily PM10 emission total. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily 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 for the boilers and furnaces shall be as follows:

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 PM10 emissions from the Catalyst Regeneration System shall be calculated using the following equation:

E = FR * EF

Where:
E = Emitted PM10
FR = Feed Rate to Unit (kbbls/day)
EF = emission factor (lbs/kbbl), established by 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.

ii. Source-wide NOx Cap
By no later than January 1, 2019, combined emissions of NOx shall not exceed 0.80 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.a.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 listed in IX.H.2.a.ii.A above apply until such time as stack testing is conducted as outlined below:

NOx stack testing on natural gas/refinery fuel gas combustion equipment above 40 MMBtu/hr shall be conducted at least once every three (3) years. 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.2.a.ii.A above. Stack testing shall be performed as outlined in IX.H.1.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.2.a.ii.A above

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

The daily 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 as outlined in IX.H.1.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 Catalyst Regeneration System.

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

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO2 Cap
By no later than January 1, 2019, combined emissions of SO2 shall not exceed 0.60 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. 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)]

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 as outlined in IX.H.1.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.

The daily SO2 emission from the FCC 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 as outlined in IX.H.1.f

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

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

Results shall be tabulated for each day, and records shall be kept which include the CEM readings for H_2S (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.

b. 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: 0.6 g NOx / kW-hr

B. GT #2 and GT #3 (each TITAN Turbine)
Exhaust Stack: 7.5 lb NOx / hr

ii. Compliance to the above emission limitations shall be determined by stack test. Stack testing shall be performed as outlined in IX.H.1.e.

A. 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.

c. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

i NO_X 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. 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.1.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 determined by examination of electrical meters, which shall record electricity production on a continuous basis.

d. Chevron Products Company

i. Source-wide PM10 Cap

By no later than January 1, 2019, combined emissions of PM10 shall not exceed 0.715 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.d.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM10: 1.9 lb/MMscf
Condensable PM10: 5.7 lb/MMscf

Plant gas:
Filterable PM10: 1.9 lb/MMscf
Condensable PM10: 5.7 lb/MMscf

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

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

Cooling Towers: shall be determined from the latest edition of AP-42

FCC Stack:
The PM10 emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

B. The default emission factors listed in IX.H.2.d.i.A above apply until such time as stack testing is conducted as outlined below:

PM10 stack testing on the FCC stack shall be conducted at least once every three (3) years. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM10 Cap shall be determined for each day as follows:

Total 24-hour PM10 emissions for the emission points shall be calculated by adding the daily results of the PM10 emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, the FCC and the SRUs to arrive at a combined daily PM10 emission total. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

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

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

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

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NOx Cap

By no later than January 1, 2019, combined emissions of NOx shall not exceed 2.1 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.d.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.2.d.ii.A above apply until such time as stack testing is conducted as outlined below:

NOx stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr shall be conducted at least once every three (3) years. 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.2.d.ii.A above. Stack testing shall be performed as outlined in IX.H.1.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. 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 as outlined in IX.H.1.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.

iii. Source-wide SO2 Cap

By no later than January 1, 2019, combined emissions of SO2 shall not exceed 1.05 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. The default emission factors to be used are as follows:

FCC Regenerator: The emission rate shall be determined by the FCC Regenerator SO2 CEM as outlined in IX.H.1.f

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 as outlined in IX.H.1.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 H_2S measurement obtained from the H_2S CEM. The emission factor shall be calculated as follows:

EF (lb SO_2/MMscf gas) = (24 hr avg. ppmdv H_2S) /10^6 * (64 lb SO_2/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.

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows:

Total daily SO_2 emissions shall be calculated by adding the daily SO_2 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 the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), and the calculated 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.

e. Hexcel Corporation: Salt Lake Operations

i. The following limits shall not be exceeded for fiber line 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. After a shutdown and prior to startup of a fiber line, all control equipment shall be started and remain in operation during production. Control equipment on each fiber line may consist of incinerators, baghouses, and regenerative thermal oxidizers.

A. The proper operation of control equipment shall be determined by maintaining records of control equipment that is not operating while the fiber line(s) in production.

f. Holly Refining and Marketing Company

i. Source-wide PM10 Cap

By no later than January 1, 2019, PM10 emissions (filterable + condensable) from all sources shall not exceed 0.416 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.g.i.B below, the default emission factors to be used are as follows:

Natural gas or Plant gas:
non-NSPS combustion equipment: 7.65 lb PM10/MMscf
NSPS combustion equipment: 0.52 lb PM10/MMscf

Fuel oil:
The filterable PM10 emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

PM10 (lb/1000 gal) = (10 * wt. % S) + 3.22

The condensable PM10 emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.

Cooling Towers: The PM10 emission factor shall be determined from the latest edition of AP-42.

FCC Wet Scrubbers:
The PM10 emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

B. The default emission factors listed in IX.H.2.g.i.A above apply until such time as stack testing is conducted as outlined below:

Stack testing on all NSPS combustion equipment shall be conducted at least once every three (3) years. At that time a new flow-weighted average emission factor in terms of: lb PM10/MMBtu shall be derived. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM10 Cap shall be determined for each day as follows:

Total 24-hour PM10 emissions for the emission points shall be calculated by adding the daily results of the PM10 emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and wet scrubbers to arrive at a combined daily PM10 emission total. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters 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), 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 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.2.g.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
Selective catalytic reduction (SCR): 0.02 lbs/MMbtu
All other combustion burners: 100 lb/MMscf

Where:
"Natural gas/refinery fuel gas" shall represent any combustion of natural gas, refinery fuel gas, or combination of the two in the associated burner.

All fuel oil combustion: 120 lbs/Kgal

B. The default emission factors listed in IX.H.2.f.ii.A above apply until such time as stack testing is conducted as outlined in IX.H.1.e or by NSPS.

C. Compliance with the Source-wide 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.

iii. Source-wide SO2 Cap

By no later than January 1, 2019, the emission of SO2 from all emission points shall not exceed 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 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 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 SO_2/kgal) = (density lb/gal) * (1000 gal/kgal) * (wt. %S)/100 * (64 g SO_2/32 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 SO_2 Cap shall be determined for each day as follows:

Total daily SO_2 emissions shall be calculated by adding daily results of the SO_2 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 every day; and records shall be kept which include the CEM readings for H_2S (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.

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.

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, 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 on unpaved access roads that receive haul truck traffic and light vehicle traffic.

E. KUC is subject to the requirements in the 1994 federally approved Fugitive Emissions and Fugitive Dust rules, R307-1-4.5.

h. Kennecott Utah Copper (KUC): Power Plant and Tailings Impoundment

i. Utah Power Plant

A. Boilers #1, #2, and #3 shall not be operated upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine).

B. Unit #5 shall not exceed the following emission rates to the atmosphere:

Pollutant	lb/hr	lb/event	ppmdv (15% O_2 dry)
I. PM_{10} with duct firing:			
Filterable + condensable	18.8		
II. NO_x:			2.0
Startup/shutdown		395	

III. Startup / Shutdown Limitations:

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

2. The NO_x emissions shall not exceed 395 lbs from each startup/shutdown event, which shall be calculated using manufacturer data.

3. Definitions:

(i) Startup cycle duration ends when the unit achieves half of the design electrical generation capacity.

(ii) Shutdown duration cycle begins with the initiation of turbine shutdown sequence and ends when fuel flow to the gas turbine is discontinued.

C. Upon commencement of operation of Unit #5*, stack testing to demonstrate compliance with the emission limitations in IX.H.2.h.i.B shall be performed as follows for the following air contaminants

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

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

Pollutant	Test Frequency
I. PM_{10}	3 years
II. NO_x	3 years

D. The following requirements are applicable to Units #1, #2, #3, and #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. 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 68^{o}F, 29.92 in. Hg	grains/dscf	ppmdv (3% O_2)
1. PM_{10} Units #1, #2, #3 and #4		
filterable	0.004	
filterable + condensable	0.03	
2. NOx:		
Units #1, #2 and #3 (each)		336
3. NO_x		
Unit #4		336
(Unit 4 after January 1, 2018)		60

III. When using coal as a fuel during a curtailment of the natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Pollutant 68^{o}F, 29.92 in Hg	grains/dscf	ppmdv (3% O_2)
1. Units #1, #2 and #3		
(i) PM_{10}		
filterable	0.029	
filterable +		

condensable	0.29	
(ii) NO_x Units 1, 2 & 3		426.5
2. Unit #4		
(i) PM_{10}		
filterable	0.029	
filterable + condensable	0.29	
(ii) NO_x		384

IV. If the units operated during the months specified above, stack testing to show compliance with the emission limitations in H.2.h.i.D.II and III shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency	Initial Test
1. PM_{10}	3 years	*
2. NO_x	3 years	*

* Initial compliance testing is required for Unit #4 after low NO_x 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 limited use of natural gas during maintenance firings and break-in firings does not constitute operation and does not require stack testing.

E. The following requirements are applicable to 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 68^{o}F, 29.92 in Hg	ppmdv (3% O_2)
1. Units #1, #2, and #3		
(i) PM_{10} filterable	0.029	
(ii) NO_x Units #1, #2, and3		426.5
2. Unit #4		
(i) PM_{10} filterable	0.029	

(ii) NO_x 384

II. If the units operated during the months specified above, stack testing to show compliance with the emission limitations in H.2.h.i.E.I shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency
1. PM_{10}	every year
2. NO_x	every year

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

F. The sulfur content of any fuel burned shall not exceed 0.66 lb of sulfur per million BTU per test.

I. Coal increments will be collected using ASTM 2234, Type I conditions A, B, or C and systematic spacing.

II. Percent sulfur content and gross calorific value of the coal on a dry basis will be determined for each gross sample using ASTM D methods 2013, 3177, 3173, and 2015.

III. KUC shall measure at least 95% of the required increments in any one month that coal is burned in Units #1, #2, #3 or #4.

ii. Tailings Impoundment

A. No more than 50 contiguous acres or more than 5% of the total tailings area shall be permitted to have the potential for wind erosion.

I. Wind erosion potential is the area that is not wet, frozen, vegetated, crusted, or treated and has the potential for wind erosion.

II. KUC shall conduct wind erosion potential grid inspections monthly between February 15 and November 15. The results of the inspections shall be used to determine wind erosion potential.

III. If KUC or the Director of Utah Division of Air Quality (Director) determines that the percentage of wind erosion potential is exceeded, KUC shall develop a corrective action plan and implementation schedule within 60 days following verbal notification by either party. KUC shall then meet with the Director, to discuss the modified fugitive dust controls/operational practices, and an implementation schedule for such.

B. If between February 15 and November 15 KUC's weather forecast is for a wind event (a wind event is defined as wind gusts exceeding 25 mph for more than one hour) the procedures listed below shall be followed within 48 hours of issuance of the forecast. KUC shall:

I. Alert the Utah Division of Air Quality promptly.

II. Continue surveillance and coordination of appropriate measures.

C. KUC is subject to the requirements in the 1994 federally approved Fugitive Emissions and Fugitive Dust rule, R307-1-4.5.

i. Kennecott Utah Copper (KUC): Smelter & Refinery

i. Smelter

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

I. Main Stack (Stack No. 11)

1. PM_{10}
   a. 89.5 lbs/hr (filterable, daily average)
   b. 439 lbs/hr (filterable + condensable, daily average)

2. SO_2
   a. 552 lbs/hr (3 hr. rolling average)
   b. 422 lbs/hr (daily average)

3. NO_X
   a. 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_X
   a. 9.34 lbs/hr, 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)	PM10	every year
	SO2	CEM
	NOx	CEM
II. Holman Boiler	NOx	CEM or alternate method determined according to applicable NSPS standards

C. During startup/shutdown operations, NO_x and SO_2 emissions are monitored by CEMS or alternate methods in accordance with applicable NSPS standards.

ii. Refinery:

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

Emission Point	Pollutant	Maximum Emission Rate
The sum of two (Tankhouse) Boilers	NO_X	9.5 lbs/hr
Combined Heat Plant	NO_X	5.96 lbs/hr

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

Emission Point	Pollutant	Testing Frequency
Tankhouse Boilers	NO_x	every three years
Combined Heat Plant	NO_x	every year

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. Stack testing will be performed only on boilers operating more than 100 hours per calendar year for steam generation for the facility.

C. Standard operating procedures shall be followed during startup and shutdown operations to minimize emissions.

iii. Molybdenum Autoclave Project (MAP):

A. Emissions to the atmosphere from the Natural Gas Turbine combined with Duct Burner and with Turbine Electric Generator (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. Standard operating procedures shall be followed during startup and shutdown operations to minimize emissions.

j. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

A. Emissions of NOx shall be no greater than 179 lbs/hr

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.1.f.

ii. Steam Generating Unit #2:

A. Emissions of NOx shall be no greater than 204 lbs/hr

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, applicable between November 1 and February 28/29

II. 203 lbs/hr, 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.1.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 22.2 lbs/hour (15% O2, dry) based on a 30-day rolling average.

B. 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.

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NOx and O2 monitors to determine compliance with the NOx limitation. The CEM shall operate as outlined in IX.H.1.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 600 ^{o}F, the stack inlet temperature reaches 570 ^{o}F, 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.

k. Tesoro Refining & Marketing Company

i. Source-wide PM10 Cap

By no later than January 1, 2019, combined emissions of PM10 shall not exceed 2.25 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.k.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM10: 1.9 lb/MMscf
Condensable PM10: 5.7 lb/MMscf

Plant gas:
Filterable PM10: 1.9 lb/MMscf
Condensable PM10: 5.7 lb/MMscf

Fuel Oil: The PM10 emission factor shall be determined from the latest edition of AP-42

Cooling Towers: The PM10 emission factor shall be determined from the latest edition of AP-42

FCC Wet Scrubbers:
The PM10 emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

B. The default emission factors listed in IX.H.2.k.i.A above apply until such time as stack testing is conducted as outlined below:

PM10 stack testing on the FCCU wet gas scrubber stack shall be conducted at least once every three (3) years. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the Source-wide PM10 Cap shall be determined for each day as follows:

Total 24-hour PM10 emissions for the emission points shall be calculated by adding the daily results of the PM10 emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and wet scrubber and to the estimate for the SRU/TGTU/TGI to arrive at a combined daily PM10 emission total. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

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

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

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

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NOx Cap

By no later than January 1, 2019, combined emissions of NOx shall not exceed 1.988 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.k.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.2.k.ii.A above apply until such time as stack testing is conducted as outlined below:

NOx stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr shall be conducted at least once every three (3) years. 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.2.k.ii.A above. Stack testing shall be performed as outlined in IX.H.1.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 mass flow of the flue gas. The NOx concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

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

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

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO2 Cap

By no later than January 1, 2019, combined emissions of SO2 shall not exceed 3.1 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. 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 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.

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 SO_2 emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas. The SO_2 concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

Daily SO_2 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 the CEM readings for H_2S (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.

l. 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:

Emission Point	Pollutant	ppmdv (3% O_2 dry)
A. Boiler #3	NO_x	187
B. Boilers #4a & #4b	NOx	9
C. Boilers #5a & #5b	NOx	9
D. Turbine	NO_x	9
E. Turbine and WHRU Duct burner	NO_x	15

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

ii. Testing to show compliance with the emissions limitations of Condition i above shall be performed as specified below:

Emission Point	Pollutant	Initial Test	Test Frequency
A. Boiler #3	NO_x	*	every 3 years
B. Boilers #4a & 4b	NOx	2018	every 3 years
C. Boilers #5a & 5b	NOx	2017	every 3 years
D. Turbine	NO_x	*	every 3 years
E. Turbine and WHRU Duct burner	NO_x	*	every 3 years

* Initial tests have been performed and the next test shall be performed within 3 years of the last stack test.

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 NO_X burners or is replaced with a boiler that has low NO_x burners.

m. West Valley Power Holdings, LLC.: West Valley Power Plant.

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. The CEM shall operate as outlined in IX.H.1.f.

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.

H.3 Source Specific Emission Limitations in Utah County PM10 Nonattainment/Maintenance 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.

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

Emission Point	Pollutant	ppm (7% O_2 dry)*		lb/hr	
A. Unit #1	NO_x	95	36	9.55	5.44
B. Unit #4	NO_x	127	36	38.5	19.2
C. Unit #6	NO_x	127	36	38.5	19.2

* Unit #1 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 limit for units #4 and #6 is 127 ppm (38.5 lb/hr) and starting on January 1, 2017, the limit will then be 36 ppm (19.2 lb/hr).

Emission Point	Pollutant	ppm (7% O_2 dry)	lb/hr
D. Unit #2	NO_x	331	37.4
E. Unit #3	NO_x	331	37.4
F. Unit #5	NO_x	331	74.8

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

Emission Point	Pollutant	Initial test	Test Frequency
A. Unit #1	NO_X	&	every three years
B. Unit #2	NO_X	#	every three years
C. Unit #3	NO_X	#	every three years
D. Unit #4	NO_X	#	every three years
E. Unit #5	NO_X	#	every three years
F. Unit #6	NO_X	#	every three years

Stack tests shall be performed in accordance with IX.H.1.e.

& If Unit #1 is operated for more than 100 hours per rolling 12-month period, the stack test shall be performed within 60 days of exceeding 100 hours of operations. Unit #1 shall only be operated as a back-up boiler to Units #4 and #6 and shall not be operated more than 300 hours per rolling 12-month period. If Unit #1 operates more than 300 hours per rolling 12-month period, then low NO_X burners with Flue Gas Recirculation shall be installed and tested within 18 months of exceeding 300 hours of operation and the maximum NO_x concentration shall be 36 ppm.

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, 2017.

iv. Central Heating Plant Natural Gas-Fired Boilers

A. Startup and shutdown events shall not exceed 216 hours per boiler per 12-month rolling period.

B. 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 approved equivalent

II. 0.60% by weight as determined by ASTM Method D-4239-85, or approved equivalent.

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.

b. Geneva Nitrogen Inc.: Geneva Nitrogen Plant

i. Prill Tower:

PM_{10} emissions (filterable and condensable) shall not exceed 0.236 ton/day
$PM_{2.5}$ emissions (filterable and condensable) shall not exceed 0.196 ton/day

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

ii. Testing

A. Stack testing shall be performed as specified below:

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

B. The daily limit shall be calculated by multiplying the most recent stack test results by the appropriate hours of operation for each day.

iii. Montecatini Plant:

NO_X emissions shall not exceed 30.8 lb/hr

iv. Weatherly Plant:

NO_X emissions shall not exceed 18.4 lb/hr

v. Testing

Stack testing to show compliance with the NO_x emission limitations shall be performed every three years.

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

vi. Start-up/Shut-down

A. Startup / Shutdown Limitations:

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

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

c. PacifiCorp Energy: Lake Side Power Plant

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.1.f

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.1.f

iii. Startup / Shutdown Limitations:

A. Block #1:

I. Startup and shutdown events shall not exceed 613.5 hours per turbine per 12-month rolling period.

II. Total startup and shutdown events shall not exceed 14 hours per turbine in any one calendar day.

III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12- month rolling period.

IV. During periods of transient load conditions, 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 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O2.

C. Definitions:

I. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr emission limits listed in IX.H.3.c.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% O_2. Transient load conditions include 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

b. Emissions of NO_X shall be no greater than 1.54 ton per day for all engines combined.

c. 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)

i. 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.1.e. Each engine shall be tested at least every three years from the previous test.

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

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

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

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

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

A. The NO_x emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall be tested every 8,760 hours of operation or at least every three years from the previous test, whichever occurs first.

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

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

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

g. Springville City Corporation: Whitehead Power Plant

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

ii. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM. CEM will be performed in accordance with IX.H.1.f. A day is equivalent to the time period from midnight to the following midnight. Emissions shall be calculated for NOx 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

H.4 Interim Emission Limits and Operating Practices

a. The terms and conditions of this Subsection IX.H.4 shall apply to the sources listed in this section on a temporary basis, as a bridge between the 1991 PM10 State Implementation Plan and this PM10 Maintenance Plan. For all other point sources listed in IX.H.2 and IX.H.3 the limits apply upon approval by the Utah Air Quality Board of the PM10 Maintenance Plan. These bridge requirements are needed to impose limits on the sources that have time delays for implementation of controls. During this timeframe, the sources listed in this section may not meet the established limits listed in IX.H.2 and IX.H.3. As the control technology for the sources listed in this section is installed and operational, the terms and conditions listed in IX.H.1 through 3 become applicable and those limits replace the limits in this subsection.

b. Petroleum Refineries:

i. All petroleum refineries in or affecting the PM_{10} nonattainment/maintenance area shall, for the purpose of this PM_{10} Maintenance Plan:

A. Achieve an emission rate equivalent to no more than 9.8 kg of SO_2 per 1,000 kg of coke burn- off from any Catalytic Cracking unit by use of low-SO_x catalyst or equivalent emission reduction techniques or procedures, including those outlined in 40 CFR 60, Subpart J. Unless otherwise specified in IX.H.2, compliance shall be determined for each day based on a rolling seven-day average.

B. Compliance Demonstrations.

I. Compliance with the maximum daily (24-hr) plant-wide emission limitations for PM_{10}, SO_2, and NO_x shall be determined by adding the calculated emission estimates for all fuel burning process equipment to those from any stack-tested or CEM-measured source components. NO_x and PM_{10} emission factors shall be determined from AP-42 or from test data.

For SO_x, the emission factors are:

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Plant gas: the emission factor shall be calculated from the H_2S measurement required in IX.H.1.g.ii.A.

Fuel oils (when permitted): The emission factor shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or approved equivalent, and the density of the fuel oil, as follows:

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO_2/32 lb S)

Where mixtures of fuel are used in an affected unit, the above factors shall be weighted according to the use of each fuel.

II. Daily emission estimates for stack-tested source components shall be made by multiplying the latest stack-tested hourly emission rate times the logged hours of operation (or other relevant parameter) for that source component for each day. This shall not preclude a source from determining emissions through the use of a CEM that meets the requirements of R307-170.

c. Big West Oil Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all external combustion process equipment shall not exceed the following:

I. 0.377 tons per day, between October 1 and March 31;
II. 0.407 tons per day, between April 1 and September 30.

B. Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

The daily primary PM_{10} contribution from the Catalyst Regeneration System shall be calculated using the following equation:

Emitted PM_{10} = (Feed rate to FCC in kbbl/time) * (22 lbs/kbbl)

wherein the emission factor (22 lbs/kbbl) may be re-established by stack testing. Total 24-hour PM_{10} emissions shall be calculated by adding the daily emissions from the external combustion process equipment to the estimate for the Catalyst Regeneration System.

ii. SO_2 Emissions

A. Combined emissions of sulfur dioxide from all external combustion process equipment shall not exceed the following:

I. 2.764 tons/day, between October 1 and March 31;
II. 3.639 tons/day, between April 1 and September 30.

B. Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

The daily SO_2 emission from the Catalyst Regeneration System shall be calculated using the following equation:

SO_2 = [43.3 lb SO_2/hr / 7,688 bbl feed/day] x [(operational feed rate in bbl/day) x (wt% sulfur in feed / 0.1878 wt%) x (operating hr/day)]

The FCC feed weight percent sulfur concentration shall be determined by the refinery laboratory every 30 days with one or more analyses. Alternatively, SO_2 emissions from the Catalyst Regeneration System may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

Emissions from the SRU Tail Gas Incinerator (TGI) shall be determined for each day by multiplying the sulfur dioxide concentration in the flue gas by the mass flow of the flue gas.

Total 24-hour SO_2 emissions shall be calculated by adding the daily emissions from the external combustion process equipment to the values for the Catalyst Regeneration System and the SRU.

iii. NO_x Emissions

A. Combined emissions of NO_x from all external combustion process equipment shall not exceed the following:

I. 1.027 tons per day, between October 1 and March 31;
II. 1.145 tons per day, between April 1 and September 30.

B. Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

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

NO_x = (Flue Gas, moles/hr) x (180 ppm /1,000,000) x (30.006 lb/mole) x (operating hr/day)

wherein the scalar value (180 ppm) may be re-established by stack testing.

Alternatively, NO_x emissions from the Catalyst Regeneration System may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

Total 24-hour NO_x emissions shall be calculated by adding the daily emissions from gas-fired compressor drivers and the external combustion process equipment to the value for the Catalyst Regeneration System.

d. Chevron Products Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all external combustion process equipment shall be no greater than 0.234 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

ii. SO_2 Emissions

A. Combined emissions of sulfur dioxide from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator, shall not exceed 0.5 tons/day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Alternatively, SO_2 emissions from the FCC CO Boiler and Catalyst Regenerator may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iii. NO_x Emissions

A. Combined emissions of NO_x from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator and the SRU Tail Gas Incinerator, shall be no greater than 2.52 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Alternatively, NO_x emissions from the FCC CO Boiler and Catalyst Regenerator may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iv. Chevron shall be permitted to combust HF alkylation polymer oil in its Alkylation unit.

e. Holly Refining and Marketing Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all combustion sources, shall be no greater than 0.44 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2), or from testing as described below, by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

ii. SO_2 Emissions

A. Combined emissions of SO_2 from all sources shall be no greater than 4.714 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from sectionIX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Emissions from the FCCU wet scrubbers shall be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iii. NO_x Emissions:

A. Combined emissions of NO_x from all sources shall be no greater than 2.20 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

f. Tesoro Refining & Marketing Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from gas-fired compressor drivers and all external combustion process equipment, including the FCC/CO Boiler (ESP), shall be no greater than 0.261 tons per day.

Emissions for gas-fired compressor drivers and the group of external combustion process equipment shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

ii. SO_2 Emissions

A. Combined emissions of SO_2 from gas-fired compressor drivers and all external combustion process equipment, including the FCC/CO Boiler (ESP), shall not exceed the following:

I. November 1 through end of February: 3.699 tons/day
II. March 1 through October 31: 4.374 tons/day

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Emissions from the ESP stack (FCC/CO Boiler) shall be determined by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas.

The SO_2 concentration in the flue gas shall be determined by a continuous emission monitor (CEM).

iii. NO_x Emissions

A. Combined emissions of NO_x from gas-fired compressor drivers and all external combustion process equipment shall be no greater than 1.988 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.a.(2) by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.