Utah State Implementation Plan

Emission Limits
and Operating Practices

Section IX, Part H

Adopted by the Air Quality Board
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IX.H EMISSION LIMITS AND OPERATING PRACTICES

(Adopted 24 September 1990 and updated June 28, 1991; February 27, 1997; July 3, 2002; July 6, 2005; May 4, 2011; and sections IX.H.11, 12, and 13 were added January 8, 2014.)

IX.H.1 General Requirements.

The terms and conditions of this Subsection IX.H.1 shall apply to all sources subsequently addressed in Subsection IX.H.2 and 3. Should any inconsistencies exist between these two subsections, the source-specific conditions listed in IX.H.2 and 3 shall take precedence.

a. Stack testing to show compliance with the emission limitations for the sources in this appendix shall be performed in accordance with 40 CFR 60, Appendix A; 40 CFR 51 Appendix M; and R307-305-5. The back half condensibles are required for inventory purposes. The following test methods shall be used for the indicated air contaminants:

(1) PM_{10} For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201 or 201a plus the back half condensibles using Method 202, or other appropriate EPA approved reference method.

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, 5d, 5e, plus back half condensibles using method 202, or other appropriate EPA approved reference method. All particulate captured in the back half shall be considered PM_{10}.

The PM_{10} captured in the front half shall be considered for compliance purposes.

(2) SO_2 Appendix A, Method 6, 6A, 6B or 6C

(3) NO_X Appendix A, Method 7, 7A, 7B, 7C, 7D or 7E

(4) Sample Location Appendix A, Method 1

(5) Volumetric Flow Rate Appendix A, Method 2

(6) Calculations To determine mass emission rates, 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.

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 Executive Secretary. 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.

b. Compliance with the annual limitations shall be determined based on a rolling 12-month total. By the last day of each month a new 12-month total shall be calculated using data from the previous 12 months.

c. Any information used to determine compliance shall be recorded for all periods when the plant 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 Executive Secretary upon request.

d. All installations and facilities authorized by this regulation shall be adequately and properly maintained.

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

f. Visible emissions shall be as follows except as otherwise designated in specific source subsections:

* baghouse applications shall not exceed 10% opacity;
* scrubber and ESP applications shall not exceed 15% opacity;
* combustion sources without control facilities shall not exceed 10% opacity;
* fugitive emissions shall not exceed 15% opacity; and
* fugitive dust and all other sources shall not exceed 20% opacity.

g. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. For intermittent sources and mobile sources opacity observations shall be conducted using procedures similar to Method 9, but the requirement for observations to be made at 15-second intervals over a six minute period shall not apply.

h. All unpaved roads and other unpaved operational areas that are used by mobile equipment shall be water sprayed and/or chemically treated to control fugitive dust. Treatment shall be of sufficient frequency and quantity to maintain the surface material in a damp or moist condition, unless the ambient temperature is below freezing. The opacity shall not exceed 20% during all times. If chemical treatment other than magnesium chloride is to be used, the plan must be approved by the executive secretary. Records of water and/or chemical treatment shall be kept for all periods when the plant is in operation. The records shall include the following items:

A. Date;
B. Number of treatments made, dilution ratio, and quantity;
C. Rainfall received, if any, and approximate amount; and
D. Time of day treatments were made.

Records of treatment shall be made available to the executive secretary upon request and shall include a period of two years ending with the date of the request.

i. Petroleum Refineries.

(1) All petroleum refineries in or affecting the PM_{10} nonattainment/maintenance area shall, for the purpose of this PM_{10} SIP:

(a) remove a minimum of 95% of the sulfur from feed streams processed by the sulfur recovery unit (SRU) for all periods of operation except for startup, shutdown, or malfunction of the SRU. The feed streams to be processed shall include the acid gas from the amine regeneration unit and the sour-water stripper. SRU efficiency shall be estimated and reported to the Executive Secretary a minimum of once per year.

(b) reduce the H_2S content of the refinery plant gas to 0.10 grain/dscf (160 ppm) or less, except during startup, shutdown, or malfunction of the amine plant. Compliance shall be based on a rolling average of 24 hours. The owner/operator shall install and maintain a continuous monitoring system for monitoring the H_2S content of the refinery plant gas and a continuous recorder to record the H_2S in the plant fuel gas. The monitoring system shall comply with all applicable sections of R307-170 and 40 CFR 60, Appendix B, Specification 7. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60, Subpart J, and may be used interchangeably.

If the monitor reading is not available, the refinery plant gas shall be sampled as closely to the monitor location as safely possible at least once each day. The sample shall be analyzed for sulfur content by use of a chemical detector tube capable of reading the required concentration (e.g., Drager Hydrogen Sulfide No. 1/D or equivalent).

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

(c) no longer burn fuel oil in external combustion equipment, except during periods of natural gas curtailment or as specified in IX.H.2. External combustion shall mean combustion that takes place at no greater pressure than one inch of mercury above ambient pressure.

(d) 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-SOx 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 daily based on a rolling seven-day average.

(e) not exceed 20% opacity at any process flare. Opacity at catalytic cracking units, including those with ESP facilities, shall not exceed 20%, with compliance to be determined in accordance with Subsection (g) above.

(2) Compliance Demonstrations.

(a) (a) 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. NOx and PM10 emission factors shall be determined from AP-42 or from test data.

For SOx, the emission factors are:

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Plant gas: the emission factor shall be calculated from the H2S measurement required in IX.H.1.i(1)(b). The emission factor, where appropriate, shall be calculated as follows:

$$(\text{lb } SO_2/\text{MMscf gas}) = (24 \text{ hr avg. ppmv } H_2S)/10^6 * (64 \text{ lb } SO_2/\text{lb mole}) * (10^6 \text{ scf/MMscf}) /(379 \text{ scf / lb mole})$$

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:

$$\text{EF (lb } SO_2/\text{k gal}) = \text{density (lb/gal)} * (1000 \text{ gal/k gal}) * \text{wt.\% S}/100 * (64 \text{ lb } SO_2/32 \text{ lb S})$$

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

(b) 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) The sulfur dioxide concentration in the flue gas of Sulfur Recovery Units shall be determined by a continuous emission monitor that meets or exceeds the requirements contained in 40 CFR 60, Appendix B, Performance Specification 2. The monitor shall be maintained and calibrated in accordance with R307- 170. The mass flow rate of the flue gas shall be determined by a volumetric flow measurement device that meets or exceeds the requirements contained in 40 CFR 52 Appendix E.

(d) Any parameters necessary to determine compliance, including but not limited to: CEM data, fuel gas meter readings, hours of operation for stack-tested source components, and the calculated emissions, shall be recorded on a daily basis. These records shall be kept for a minimum of five years. Any or all of these records shall be made available to the Executive Secretary upon request.

(e) The emissions increase (above normal operations) experienced during the SRU routine turnarounds shall not be included in the daily (24-hr) or annual compliance demonstrations.

(f) Emissions due to upset flaring shall not be included in the daily (24-hr) or annual compliance demonstrations.

(3) SRU maintenance period

(a) The routine turnaround maintenance period (expected every 2 to 5 years for approximately a 15 day period) for a Sulfur Recovery Unit shall only be scheduled during the period of April 1 through October 31. The projected SRU turnaround period shall be submitted to the Executive Secretary by April 1 of each year in which a turnaround is planned. Notice shall also be provided the Executive Secretary 30 days prior to the planned turnaround.

(b) Alternatively, a source may choose to conduct its turnaround maintenance outside of the window identified in paragraph 3.A above; however, in such case the exemption provided in Subsection IX.H.1.i(2)(e) above shall no longer apply.

IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties

a. BOUNTIFUL CITY POWER

(1) (a) NO_X emissions from the 5.3 MW Turbine Exhaust Stack shall not exceed 0.0721 tons per day.

(b) Annual NO_X emissions from the entire plant shall not exceed 248.00 tons per rolling 12-month period. Combined emissions shall be the sum of emissions from natural gas fired turbine and each internal combustion engine.

Compliance with the mass emission limits shall be demonstrated by multiplying the most recent stack test results, for the turbine and each engine, by the total hours of operation along with any necessary conversion factors. Compliance with the annual limitation shall be based on a rolling 12-month total. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log.

(2) Engine #8 shall be retested to verify the emissions factors after every 800 operating hours, or at least once every 24 months. All other engines and the turbine shall be tested once a year. Emission testing for NO_X shall be performed using a portable monitoring system.

(3) If the annual NO_X emissions for the entire plant exceed 200 tons for any previous 12-month period, the owner/operator shall submit a report of the emissions to the Executive Secretary within 30 days. Within 90 days the owner/operator shall submit to the Executive Secretary for approval, a plan with proposed specifications for the installation, calibration, and maintenance of a Continuous Emissions Monitoring System (CEMS) for NO_X. The CEMS shall be on line within 12 months following the approval of the plan.

(4) Visible emissions shall be no greater than 10 percent opacity except for 15 minutes at start-up and 15 minutes at shutdown and during allowed straight fuel oil use. When straight fuel oil is used, visible emissions shall be no greater than 20 percent opacity except for operation not exceeding 3 minutes in any hour.

b. CENTRAL VALLEY WATER RECLAMATION FACILITY

(1) (a) NO_X 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.

(b) NO_X emissions from the operation of all engines at the plant shall not exceed 205.6 tons per year.

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

c. CHEVRON PRODUCTS CO.

(1) PM_{10} Emissions

DAILY LIMIT: Combined emissions of PM_{10} from all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator shall be no greater than 0.234 tons per day.

Emissions for the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.2 or from testing listed 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.

The emission factor for the FCC CO Boiler and Catalyst Regenerator shall be determined by a stack test at least once every three years.

(2) SO_2 Emissions

(a) Cap Sources:

(i) *DAILY LIMIT:* Combined emissions of sulfur dioxide from gas-fired compressor drivers and all all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator, shall not exceed 2.977 tons/day.

Emissions for gas-fired compressor drivers and the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.2 or from testing listed 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.

The emission factor for the FCC CO Boiler and Catalyst Regenerator shall be determined by a stack test at least once every three years. Compliance with Subsection IX.H.1.i.(1)(d) shall be determined as part of each test.

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.i.2.b.

(ii) *12-MONTH LIMIT:* Emissions of SO_2 from all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator, shall be no greater than 953.9 tons per rolling twelve-month period.

(b) Sulfur Recovery Unit (SRU):

Emissions of SO_2 from the SRU shall not exceed 2.128 tons/day.

Emissions from the SRU Tail Gas Incinerator (TGI) shall be determined daily by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas.

Whenever the SO_2 CEM is bypassed for short periods, SO_2 CEM data from the previous three days will be averaged and used as an emission factor to determine emissions.

(3) NO_X Emissions

(a) *DAILY LIMIT:*

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 3.248 tons per day.

Emissions for gas-fired compressor drivers and the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.2 or from testing listed 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.

The emission factor for the FCC CO Boiler and Catalyst Regenerator shall be determined by a stack test at least once every three years.

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.i.2.b.

(b) *12-MONTH LIMIT:*

Emissions of NO_X from gas-fired compressor drivers and all external combustion process equipment, including FCC CO Boiler and Catalyst Regenerator and the SRU Tail Gas Incinerator, shall be no greater than 1,021.6 tons per rolling twelve-month period.

(4) Chevron shall not be required to comply with the emission rates outlined in Subsection IX. H.1.i.(1)(d) until January 1, 2007.

(5) Chevron shall be permitted to combust HF alkylation polymer oil in its Alkylation unit.

d. FLYING J INC., BIG WEST OIL CO.

(1) PM_{10} Emissions

(a) *DAILY LIMIT:*

(i) Combined emissions of PM_{10} from all external combustion process equipment, including the SRU Tail Gas Incinerator and the Catalyst Regeneration System, shall not exceed the following:

(A) 0.377 tons per day, between October 1 and March 31;
(B) 0.407 tons per day, between April 1 and September 30.

(ii) Emissions for the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.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:

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

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.

(b) *12-MONTH LIMIT:* PM_{10} emissions from all sources shall not exceed 71 tons. Compliance shall be based on a rolling 12-month total.

(2) SO_2 Emissions

(a) Plantwide

(i) Daily Limit: Combined emissions of sulfur dioxide from all external combustion process equipment, including the SRU Tail Gas Incinerator and the Catalyst Regeneration System, shall not exceed the following limits:

(A) 2.764 tons/day, between October 1 and March 31;
(B) 3.639 tons/day, between April 1 and September 30.

(ii) Emissions for the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.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:

$$SO_2 = [43.3 \text{ lb } SO_2/\text{hr} / 7{,}688 \text{ bbl feed/day}] \times [(\text{operational feed rate in bbl/day}) \times (\text{wt\% sulfur in feed} / 0.1878 \text{ wt\%}) \times (\text{operating hr/day})]$$

wherein the scalar values (43.3 lb SO_2/hr, 7,688 bbl feed/day, and 0.1878 wt% sulfur in feed) shall be re-established by stack testing at least every five years. Compliance with Subsection IX.H.1.i.(1)(d) shall also be determined as part of each test.

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.i.2.b.

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.

(b) *INDIVIDUAL POINT SOURCE LIMITATION:* The Sulfur Recovery Unit (SRU) shall be regulated individually for SO_2 at the following emission limits:

October 1 through March 31	0.5323 tons per day;
April 1 through September 30	0.6927 tons per day

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

(c) *THE 12-MONTH SO_2 EMISSION LIMIT* for the Entire Refinery shall be 712.5 tons per rolling 12-month period. Of this amount, emissions from the sulfur treatment plant shall not exceed 223.58 tons per 12-month period.

(3) NO_X Emissions

(a) *DAILY LIMIT*:

(i) Combined emissions of NO_X from gas-fired compressor drivers and all external combustion process equipment, including the Catalyst Regeneration System, shall not exceed the following:

(A) 1.027 tons per day, between October 1 and March 31;
(B) 1.145 tons per day, between April 1 and September 30.

(ii) Emissions for gas-fired compressor drivers and the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.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:

$$NO_X = (\text{Flue Gas, moles/hr}) \times (180 \text{ ppm} / 1{,}000{,}000) \times (30.006 \text{ lb/mole}) \times (\text{operating hr/day})$$

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

Alternatively, NO_X emissions from the Catalyst Regeneration System may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.i.2.b.

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.

(b) *12-MONTH LIMIT:* NO_X from gas-fired compressor drivers and all external combustion process equipment, including the Catalyst Regeneration System, shall not exceed 396.7 tons per rolling 12-month period.

e. GENEVA ROCK PRODUCTS, POINT OF THE MOUNTAIN (Hansen Pit and Mount Jordan Pit)

(1) PM_{10} emissions from the Asphalt Plant Baghouse Stack (APBH) shall not exceed 0.127 tons per day.

Compliance with the daily mass emission limits shall be demonstrated by multiplying the most recent stack test results, along with any necessary conversion factors, by the appropriate hours of operation for each day. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

(2) Stack testing shall be performed as specified below:

POLLUTANT	*TEST FREQUENCY*
PM_{10} (virgin materials)	5 years
PM_{10} (recycle asphalt)	3 years

When testing for PM_{10} emissions during manufacture of recycle asphalt, recycle asphalt shall be introduced into the plant at a rate no less than 45% of the plant production

(3) Visible emissions from the following emission points shall not exceed the following values:

(a) All crushers - 10% opacity
(b) All screens - 10% opacity
(c) All conveyor transfer points - 10% opacity
(d) Conveyor drop points - 15% opacity

(4) The following production limits are the combined totals for the Hansen Pit and the Mount Jordan Pit:

(a) *ASPHALT PLANT*

(i) 500 tons of asphalt produced per hour (averaged over each operating day).
(ii) 50% recycle asphalt used in the manufacture of asphalt (averaged over each operating shift).

(b) *CONCRETE BATCH PLANT*

2,400 cubic yards of concrete produced per 24-hour period.

(c) *AGGREGATE PITS*

37,944 tons per 24-hour period of aggregate crushing and screening production.

f. HOLLY REFINING AND MARKETING CO.

(1) PM_{10} Emissions

DAILY LIMIT:

Combined emissions of PM10 from all external combustion process equipment, including the Sulfur Recovery Unit Tail Gas Incinerator, shall be no greater than 0.444 tons per day.

Emissions for the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.2 or from testing 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.

The emission factor for the (51-6) CO Boiler shall be determined by stack test. Testing is required once at least every five years.

(2) SO_2 Emissions

DAILY LIMIT:

Combined emissions of SO_2 from gas-fired compressor drivers and all external combustion process equipment, including the Sulfur Recovery Unit Tail Gas Incinerator, shall be no greater than 4.714 tons per day.

Emissions for gas-fired compressor drivers and the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.2 or from testing 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.

Fuel Oil - 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 in external combustion process equipment only during periods of natural gas curtailment.

The emission factor for the (51-6) CO Boiler shall be determined by stack test. Testing is required at least once every five years. Compliance with Subsection IX.H.1.i.(1)(d) above shall be determined as part of each test. Alternatively, SO_2 emissions from the (51-6) CO Boiler may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.i.2.b.

Emissions from the SRU/TGI shall be determined daily by multiplying the sulfur dioxide concentration in the flue gas by the mass flow of the flue gas.

(3) NO_X Emissions:

(a) *DAILY LIMIT:*

Combined emissions of NO_X from gas-fired compressor drivers and all external combustion process equipment, including the Sulfur Recovery Unit Tail Gas Incinerator, shall be no greater than 2.20 tons per day.

Emissions for gas-fired compressor drivers and the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.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.

(b) *12-MONTH LIMIT:*

Combined emissions of NO_X from gas-fired compressor drivers and all external combustion process equipment, including the Sulfur Recovery Unit Tail Gas Incinerator, shall be no greater than 693.0 tons per rolling twelve-month period.

g. INTERSTATE BRICK

(1) Emissions to the atmosphere from the indicated emission point shall not exceed the following rate:

(a) Scrubber Emissions - Tunnel Kiln #1:

(i) PM_{10} 0.150 tons/day
(ii) SO_2 0.120 tons/day
(iii) NO_X 0.209 tons/day

(b) Scrubber Emissions - Tunnel Kiln #3:

(i) PM_{10} 0.288 tons/day
(ii) SO_2 0.144 tons/day
(iii) NO_X 0.310 tons/day

(c) Scrubber Emissions - Tunnel Kiln #4:

(i) PM_{10} 0.458 tons/day
(ii) SO_2 0.216 tons/day
(iii) NO_X 0.150 tons/day

Compliance with the daily mass emission limits shall be demonstrated by multiplying the most recent stack test results, along with any necessary conversion factors, by the appropriate hours of operation for each day. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

(2) Stack testing shall be performed as specified below:

POLLUTANT	*TEST FREQUENCY*
PM_{10} (Kilns #1, 3, & 4)	every 5 years after initial compliance test
NO_X (Kilns #1, 3, & 4)	every 5 years after initial compliance test
SO_2 (Kilns #1, 3, & 4)	every year

h. KENNECOTT UTAH COPPER: MINE

(1) *BINGHAM CANYON MINE:*

(a) Total material moved (ore and waste) shall not exceed 260,000,000 tons per 12-month period

(b) Annual emissions of SO_2 from the combustion of fuel shall not exceed 97 tons per year. SO_2 emissions from fuel burning shall be determined using the following equation:

tpy SO_2 = (gal fuel / year) * (7.05 lb/gal) * (% S by wt.) / 2000 lb/ton * (2 lb SO_2 / lb S)

(c) The sulfur content of diesel fuel oil burned in the equipment engines shall not exceed 0.03 pounds of sulfur per million BTU heat input as determined by the appropriate ASTM Method. This represents 0.05% sulfur by weight in the fuel oil.

i. KENNECOTT UTAH COPPER: POWER PLANT and TAILINGS IMPOUNDMENT

(1) *UTAH POWER PLANT*

The following requirements, subsections (a) through (f), are applicable unless and until the owner/operator has complied with the requirements set forth in Subsection (g) below.

(a) During the period from November 1, to the last day in February, inclusive, the following conditions shall apply:

(i) The four boilers shall use only natural gas 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) Fuel usage shall be limited to the following:

(A) 42,706 MMBTU per day of natural gas
(B) 31,510 MMBTU per day of coal, only during curtailment of natural gas supply

(iii) *NATURAL GAS USED AS FUEL:*

Except during a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates:

(A) For each of boilers no. 1, 2, & 3:

NO_X 1.91 ton/day

(B) For boiler no. 4:

NO_X 3.67 ton/day

(iv) *COAL USED AS FUEL:*

Emissions to the atmosphere from the indicated emission point shall not exceed the following rates:

(A) For each of boilers no. 1, 2, & 3:

(I) PM_{10} 0.208 ton/day
(II) NO_X 2.59 ton/day

(B) For boiler no. 4:

(I) PM_{10} 0.402 ton/day
(II) NO_X 4.52 ton/day

(v) Owner/operator shall provide monthly reports to the Executive Secretary showing daily total emission estimates based upon boiler usage, fuel consumption and previously available results of stack tests.

(b) During each annual period from March 1 to October 31, inclusive, the following conditions shall apply:

(i) KUCC shall use coal, natural gas, oils that meet all the specifications of 40 CFR 266.40(e) and contains less than 1000 ppm total halogens, and/or number two fuel oil or lighter in the boilers.

(ii) The following limit on fuel usage shall not be exceeded:

50,400 MMBTU per day of heat input

(iii) Emissions to the atmosphere from each emission point shall not exceed the following rates and concentrations:

(A) For each of boilers no. 1, 2 & 3:

(I) PM_{10} 0.208 ton/day
(II) NOx 2.59 ton/day

(B) For boiler no. 4:

(I) PM_{10} 0.402 ton/day
(II) NOx 4.52 ton/day

(c) Stack testing to show compliance with the above emission limitations shall be performed as follows for all four boilers and the following air contaminants:

	POLLUTANT	TESTING FREQUENCY
(i).	NO_X	every year
(ii)	PM_{10}	every year

The heat input during all compliance testing shall be no less than 90% of the design rate. To determine mass emission rates (ton/day) the pollutant concentration as determined by the appropriate methods 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.

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.

(d) Visible emissions from the boiler stacks shall not exceed the associated opacity on a six-minute average, based on 40 CFR 60, Appendix A, Method 9, or as measured by a Continuous Opacity Monitor except as provided for in R307-305-3(4):

(i)	Natural Gas as Fuel	10% opacity
(ii)	Coal as Fuel	20% opacity

(e) The sulfur content of any fuel burned shall not exceed 0.52 lb of sulfur per million Btu (annual running average), nor shall any one test exceed 0.66 lb of sulfur per million Btu. The owner/operator shall submit monthly reports of sulfur input to the boilers. The reports shall include:

* sulfur content,
* gross calorific value and moisture content of each gross coal sample,
* the gross calorific value of all coal and gas,
* the total amount of coal and gas burned, and
* the running annual average sulfur input calculated at the end of each month of operation.

(f) To determine compliance with a daily limit owner/operator shall calculate a daily limit. The BTU limit shall be determined by monitoring the daily natural gas, and/or coal consumption and multiplying that value with the BTU rating of the fuel consumed. The natural gas BTU used shall be that value supplied by the natural gas vendor from the previous months bill. The BTU limit for coal shall be determined by monitoring the daily coal consumption and multiplying that value with the coal BTU rating. KUCC shall provide test certification for each load of coal received. Test certification for each load received shall be defined as test once per day for coal received that day from each supplier. Certification shall be either by their own testing or test reports from the coal marketer. Records of BTU fuel usage shall be kept on a daily basis.

(g) The requirements set forth in conditions (a) – (f) above shall apply at the Utah Power Plant unless and until the following occur:

(i) A Notice of Intent is submitted to the Executive Secretary, pursuant to the procedures of R307-401, that describes the specific technologies that will be used.

(ii) An Approval Order is issued that authorizes implementation of the approach set forth in the Notice of Intent.

(iii) 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.

(iv) To the extent that the current SIP requirements outlined above in conditions (a) - (f) above have been relied upon by the Utah SIP to satisfy Section 172(c)(4) or Section 175A(a) of the Clean Air Act, demonstrate that the technologies specified in the Approval Order would also provide for attainment or maintenance of the National Ambient Air Quality Standards. The demonstration required in this paragraph may incorporate modeling previously conducted by the State for the purpose of a maintenance demonstration.

(v) The technologies specified in the Approval Order have been installed and tested in accordance with the Approval Order.

(vi) The terms and conditions of the Approval Order implementing the approach set forth in the Notice of Intent have been incorporated into a Title V Operating Permit, in accordance with R307-415.

(vii) As of the effective date of the Operating Permit, the PM_{10} SO_2 and NO_x emissions limits for the Utah Power Plant boilers, 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 in the Operating Permit shall supersede conditions (a) - (f) above.

(2) *TAILINGS IMPOUNDMENT:*

(a) Visible emissions caused by fugitive dust shall not exceed 10% at the property boundary, and 20% onsite except during periods when wind speeds exceed the value specified in UAC R307-309 and control measures in the most recently approved dust control plan are being taken. The fugitive dust control plan shall utilize the fugitive dust control strategies listed in UAC R307-205 and R307-309.

(b) Kennecott shall submit reports and conduct on site inspections on the fugitive dust abatement program activities for the executive secretary as specified in the most current Approval Order and operating permit.

(c) All unpaved roads and other unpaved operational areas that are used by mobile equipment shall be water sprayed or chemically treated to control fugitive dust. Treatment shall be of sufficient frequency and quantity to maintain the surface material in a damp/moist or crusted condition.

(d) On the North Tailings Impoundment, as the embankment cells are filled during continual raising of the embankment, dust shall be controlled by the inherent high water content of the hydraulically placed cyclone underflow. Portions of the embankment that are not under active construction shall be kept wet or tackified by applying chemical stabilizing agents or water pumped from the toe ditch. Newly formed exterior slopes shall be stabilized with chemical stabilizing agents or vegetation.

(e) Disturbed or stripped areas of the North Tailings Impoundment shall be kept sufficiently moist during the project to minimize fugitive dust. This control, or other equivalent control methods, shall remain operational during the project cycle and until the areas have been reclaimed. The control methods used shall be operational as needed 24 hours per day, 365 days per year or until the area has been reclaimed.

(f) The minimum cycle time required for wetting all interior beach areas of the North Impoundment between February 15 and November 15 shall be at least every four days.

(g) On the North Tailing Impoundment Kennecott shall conduct wind erosion potential inspections monthly between February 15 and November 15. The tailings distribution system consisting of the North Tailing Impoundment shall be operated to maximize surface wetness. Wind erosion potential is the area that is not wet, frozen, vegetated, crusted or treated and has the potential for wind erosion. No more than 50 contiguous acres or more than 5% of the total North tailings area shall be permitted to have the potential for wind erosion. If it is determined that the total surface area with the potential for wind erosion is greater than 5%, or at the request of the Executive Secretary, inspections shall be conducted once every five working days. Kennecott shall immediately initiate the revised inspection schedule and the results reported to the Executive Secretary within 24 hours of the inspection. The schedule shall continue to be implemented until Kennecott measures a total surface with the potential for wind erosion of less than or equal to 5%. If Kennecott or the Executive Secretary, determines that the percentage of wind erosion potential is exceeded, Kennecott shall meet with the Executive Secretary, or Executive Secretary's staff, to discuss additional or modified fugitive dust controls/operational practices, and an implementation schedule for such, within five working days following verbal notification by either party.

(h) On the closed South Tailings Impoundment Kennecott shall conduct wind erosion potential inspections on inactive non-reclaimed areas monthly between February 15 and November 15. No more than 50 contiguous acres or more than 5% of the South Tailings impoundment tailings area shall be permitted to have the potential for wind erosion. Wind erosion potential is the area that is not wet, frozen, vegetated, crusted or treated and has the potential for wind erosion. Inactive but non-reclaimed areas are to be stabilized by chemical stabilizing agents, ponded water, sprinklers, vegetation or other methods of fugitive dust control. If it is determined by Kennecott or the Executive Secretary, that the total surface area with the potential for wind erosion is greater than 5% of total tailings area, or at the request of the Executive Secretary, inspections shall be conducted once every five working days. Kennecott shall immediately initiate the revised inspection schedule and the results reported to the Executive Secretary within 24 hours of the inspection. The schedule shall continue to be implemented until Kennecott measures a total surface with the potential for wind erosion of less than or equal to 5% total tailings area. If Kennecott or the Executive Secretary, determines that the percentage of wind erosion potential is exceeded, Kennecott shall meet with the Executive Secretary, or Executive Secretary's staff, to discuss additional or modified fugitive dust controls/operational practices, and an implementation schedule for such, within five working days following verbal notification by either party.

(i) Exterior tailings impoundment areas determined by Kennecott or the executive secretary to be sources of excessive fugitive dust shall be stabilized through vegetation cover or other approved methods. The exterior tailings surface area of the North Impoundment shall be re-vegetated or stabilized so that no more than 5% of the total exterior surface area shall be subject to wind erosion.

(j) If between February 15 and November 15 of each calendar year Kennecott's weather forecast is for a wind speed at more than 25 mph for more than one hour within 48 hours of issuance of the forecast, the procedures listed below shall be followed:

   (i) Alert the DAQ promptly.
   (ii) Continue surveillance and coordination.

(k) If a temporary or permanent shutdown occurs that would affect any area of the Kennecott Tailings Impoundment, Kennecott shall submit a final dust control plan for all areas of the Tailings Impoundment to the Executive Secretary for approval at least 60 days prior to the planned shutdown.

j. KENNECOTT UTAH COPPER: SMELTER and REFINERY

(1) *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)

(A) PM_{10}		89.5 lbs/hr (24 hr. average)
(B) SO_2	(I)	552 lbs/hr (3 hr. average – rolling)
	(II)	422 lbs/hr (24 hr. average - calendar day)
	(III)	211 lbs/hr (annual average)
(C) NO_X		35.0 lbs.hr (annual average)

(ii) Acid Plant Tail Gas

SO_2	(I)	1,050 ppmdv (3 hr. rolling average)
	(II)	650 ppmdv (6 hr. rolling average)

All annual average emissions limits shall be based on rolling 12-month averages. Based on the first day of each month, a new 12-month total shall be calculated using the previous 12 months.

Reference to stack in Condition #1 above and Condition #2 below may not necessarily refer to an exhaust point to the atmosphere. Many emission sources are commingled with emissions from other sources and exit to the atmosphere from a common emission point. "Stack" in these conditions refers to the point prior to mixing with emissions from other sources.

(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	PM_{10}	every year
(Stack No. 11)	SO_2	CEM
	NO_X	CEM
(ii) Acid Plant Tailgas	SO_2	CEM

(c) Testing Status (To be applied to (a) and (b) above)

(i) To demonstrate compliance with the main stack mass emissions limits for SO_2 and NO_X of Condition (a)(i) above, KUC shall calibrate, maintain and operate the measurement systems for continuously monitoring SO_2 and NO_X concentrations and stack gas volumetric flow rates in the main smelter stack. Such measurement systems shall meet the requirements of R307-170.

(ii) In addition to the stack test required to measure PM_{10} in (b) above, the owner/operator shall calibrate, maintain and operate a system to continuously measure emissions of particulate matter from the main stack. For purposes of determining compliance with the emission limit, all particulate matter collected shall be reported as PM_{10}. Compliance with the main stack emission limit for PM_{10} shall be demonstrated using the smelter main stack continuous particulate sampling system to provide a 24-hour value. The owner/operator may petition the Air Quality Board at any time to discontinue the operation of the continuous monitor. An analysis of the potential PM_{10} uncontrolled emissions from the main stack shall be submitted to the Executive Secretary at the time of such a petition.

(iii) The owner/operator shall install, calibrate, maintain, and operate continuous monitoring systems on the acid plant tail gas.

(iv) All monitoring systems shall comply with all applicable sections of R307-170.

(v) KUC shall maintain records of all measurements necessary for and including the expression of PM_{10}, SO_2 and NO_X emissions in terms of pounds per hour. Emissions shall be calculated at the end of each day for the preceding 24 hours for PM_{10}, SO_2 and NO_X and calculated at the end of each hour for the preceding three-hour period for SO_2. Results for each measurement or monitoring system and reports evaluating the performance of such systems shall be summarized and shall be submitted to the Executive Secretary within 20 days after the end of each month.

(d) Visible emissions from the following emission points shall not exceed the following values:

(i) Smelter Main Stack (stack 11) 20% opacity

(ii) Sources equipped with continuous opacity monitors (acid plant tailgas and main stack) shall use the compliance methods contained in 40 CFR 60.11.

(e) All gases produced during smelting and/or converting which enter the primary gas handling system shall pass through an online sulfuric acid plant. During the start-up/shutdown process of any equipment, the gas emissions shall be ducted, as necessary, either to the acid plant or to the secondary scrubber for control.

(i) A log shall be kept of any time the gases produced during smelting and/or converting are not passed through an online sulfuric acid plant. An additional log shall be kept and include the dates, times and durations of all times any gases from smelting and/or converting bypass both the acid plant and the secondary gas system. The log will serve as the monitoring requirement.

(f) The owner/operator shall employ the following measures for reducing escape of pollutants to the atmosphere and to capture emissions and vent them through a stack or stacks:

(i) Maintenance of all ducts, flues, and stacks in such a fashion that leakage of gases to the ambient air will be prevented to the maximum extent practicable.

(ii) Operation and maintenance of gas collection systems in good working order.

(iii) Making available to the Executive Secretary the preventive/routine maintenance records for the hooding systems, dust collection mechanism of waste heat boilers, furnace wet scrubbing systems, and dry electrostatic precipitators.

(iv) Weekly observation of process units.

(v) Monthly inspection of gas handling systems.

(vi) Maintenance of gas handling systems, available on call on a 24-hour basis.

(vii) Operation and maintenance of an upwind/downwind fugitive monitoring system. The owner/operator may petition the Executive Secretary to discontinue the operation of this system.

(viii) Contained conveyance of acid plant effluent solutions.

Within 90 days of approval of these conditions, KUC submitted to the Division examples of the forms and records that will be used to comply with Conditions (f) (iv) and (v) above. KUC may modify these forms and records after approval in accordance with R307-401-1.

(g) Secondary hoods and ventilation systems shall be installed on the following points to capture fugitive emissions into the secondary ventilation system or other approved pollution control devices:

(i) Concentrate Dryer Feed Chute
(ii) Slag and Matte Granulators
(iii) Smelting and Converting Furnaces
(iv) Slag Pot Filling Stations.

(2) *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	0.11 tons/day

(b) Stack testing to show compliance with the above emission limitations shall be performed as follows:

POLLUTANT	*TESTING FREQUENCY*
NO_X	every three years

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) 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 Executive Secretary within one working day of start-up. Emissions resulting from operation of the boiler on #2 fuel oil shall be reported to the Executive Secretary within 30 days following the use of #2 fuel oil in the boilers.

k. PACIFICORP, GADSBY POWER PLANT

(1) NO_X emissions from the operation of all boilers and turbines at the plant shall not exceed 6.57 tons per day. Total plant emissions shall be the sum of emissions from each of the boilers and each of the turbines.

Daily emissions from each boiler shall be determined by a continuous emission monitoring system (CEMS) as required by 40 CFR Part 75 for the Acid Rain Program.

NO_X emissions from each turbine shall be based on a rolling 30-day average.

(2) PM_{10} emissions from the operation of all boilers and turbines at the plant shall not exceed 73.89 tons per rolling 12-month period. Total plant emissions shall be the sum of emissions from each of the boilers and each of the turbines. The emissions shall be determined on a rolling 12-month total. Emission factors for PM_{10} shall be obtained from EPA's Compilation of Air Pollutant Emission Factors, AP-42.

(3) Visible emissions shall be no greater than 10 percent opacity from each turbine. In lieu of monitoring via visible emission observations, fuel usage shall be monitored to demonstrate that only pipeline-quality natural gas is used as fuel.

I. TESORO WEST COAST

(1) PM_{10} Emissions

DAILY LIMIT: Combined emissions of 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 daily by multiplying the appropriate emission factor from section IX.H.1.i.2 or from testing 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.

The FCCU/COB stack (ESP) shall be stack tested every year to determine the PM_{10} emission factor.

(2) SO_2 Emissions

(a) Cap Sources:

(i) *DAILY LIMIT* - 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:

(A) November 1 through end of February: 3.699 tons/day
(B) March 1 through October 31: 4.374 tons/day

(ii) Emissions for gas-fired compressor drivers and the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.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 daily by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas and subtracting the emissions attributable to combustion of plant gas in the CO Boiler.

The SO_2 concentration in the flue gas shall be determined by a continuous emission monitor (CEM) that meets or exceeds the requirements contained in 40 CFR 60, Appendix B, Performance Specification 2.

Whenever the SO_2 CEM is unavailable for short periods (i.e. CO boiler or ESP emergency bypass, FCCU start-up and shutdowns), SO_2 CEM data from the previous three days will be averaged and used as an emission factor to determine emissions from the FCCU.

The mass flow rate of the flue gas shall be determined by a volumetric flow measurement device that meets or exceeds the requirements contained in 40 CFR 52 Appendix E.

Emissions attributable to combustion of plant gas in the CO Boiler shall be calculated by multiplying the quantity of fuel used in the CO boiler by the emission factor for plant gas.

(b) *SULFUR RECOVERY UNIT, TAIL GAS INCINERATOR (SRU/TGI):* Emissions of SO_2 from the SRU shall not exceed 1.68 tons/day.

Emissions from the SRU/TGI shall be determined daily by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas.

(c) *12-MONTH LIMIT:* Emissions of SO_2 from the entire facility shall not exceed 1,637 tons per rolling 12-month period.

(3) NO_X Emissions

(a) *DAILY LIMIT:* 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 for gas-fired compressor drivers and the group of external combustion process equipment shall be determined daily by multiplying the appropriate emission factor from section IX.H.1.i.2 or from testing listed 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.

The emission factor for the Ultraformer Furnace (stack F1) shall be determined by stack test. Testing shall be performed once each year.

The emission factor for the Crude Unit Furnace (stack H-101) shall be determined by stack test. Testing shall be performed once every three years.

The emission factors for both trains of the cogeneration facility shall be determined by stack test. Testing shall be performed at each train once every two years, with one train tested each year.

(b) Emissions of NO_X from each gas-fired compressor driver shall be no greater than 3.20 lb/hr.

(c) *12-MONTH LIMIT:* Emissions of NO_X from gas-fired compressor drivers and all external combustion process equipment shall be no greater than 598 tons per rolling twelve-month period.

m. WEST VALLEY LEASING COMPANY LLC, WEST VALLEY POWER PLANT

Combined NO_X emissions from the operation of all five turbines under steady state operation (not including startups and shutdowns) shall not exceed 0.44 tons per day calculated on a 30-day rolling average.

NO_X emissions shall be calculated from the CEMs recorded data using 40 CFR 60 App. A, Method 19. The owner/operator shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides. The monitoring system shall be used for measuring and determining compliance.

IX.H.3 Source-Specific Particulate Emission Limitations for Utah County

a. GENEVA NITROGEN, INC.

(1) Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

(a) Montecatini Acid Plant Vent
NO_X 0.389 tons/day 140 tons/yr

(b) Weatherly Acid Plant Vent
NO_X 0.233 tons/day 83.8 tons/yr

(c) Prill Tower
PM_{10} 0.24 tons/day 86 tons/yr

Compliance with the daily and annual mass emission limits shall be demonstrated by multiplying the most recent stack test results, along with any necessary conversion factors, by the appropriate hours of operation for each day and for each rolling 12-month period. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log.

(2) Stack testing shall be performed as specified below:

	Emission Point	*Pollutant*	*Test Frequency*
(a)	Montecatini Acid Plant Vent	NO_X	every two years
(b)	Weatherly Acid Plant Vent	NO_X	every three years
(c)	Prill Tower	PM_{10}	every three years

b. GENEVA ROCK PRODUCTS, OREM PLANT

(1) During the period from November 1 to the last day in February, inclusive, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Asphalt Plant Baghouse Stack (APBH)

(a) PM_{10} 0.103 tons/day
(b) NO_X 0.568 tons/day
(c) SO_X 0.484 tons/day

Compliance with the daily mass emission limits shall be demonstrated by multiplying the most recent stack test results, along with any necessary conversion factors, by the appropriate hours of operation for each day. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

(2) Stack testing shall be performed as specified below:

EMISSION POINT	*POLLUTANT*	*TEST FREQUENCY*
Asphalt Plant	PM_{10}	3 years
	NO_X	3 years
	SOx	3 years

(3) Opacity observations of emissions from the Asphalt Plant shall be conducted at least once every 12 months.

c. PAYSON CITY POWER

(1) NO_X emissions from the operation of all engines combined shall not exceed 1.54 tons per day.

The number of kilowatt hours generated by each engine shall be recorded on a daily basis. Emission factors shall be derived from the most recent emission test results.

(2) NO_X emissions from the operation of all engines combined shall not exceed 268 tons per 12-month period.

The number of kilowatt hours generated by each engine shall be recorded on a daily basis. 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.

(3) The emission factors necessary to determine compliance with conditions (1) and (2) above shall be determined by stack test, to be performed at least once every three (3) years.

(4) Visible emissions shall be no greater than 10 percent opacity except for 15 minutes at start-up and shutdown. When straight diesel fuel is used, visible emissions shall be no greater than 20 percent opacity except for 15 minutes at start-up and shutdown .

d. PROVO CITY POWER

(1) NO_X emissions from the operation of all engines and boilers at the plant shall not exceed 2.45 tons per day.

The following equation shall be used to calculate the daily emissions from each engine:

(Power production in kW-hr/day) x (Emission rate in gram/kW-hr) x (1 lb/453.59 g) x (1 ton/2000 lbs) = tons/day

(2) NO_X emissions from the operation of all engines and boilers at the plant shall not exceed 254 tons per 12-month period.

The following equation shall be used to calculate the emissions from each engine:

(Power production in kW-hr/rolling 12-month period) x (Emission rate in gram/kW-hr) x (1 lb/453.59 g) x (1 ton/2000 lbs) = tons per rolling 12-month period

(3) Stack testing to update the emission rate factors used in Conditions (1) and (2) above shall be performed as follows:

Boiler No. 4 and Boiler No. 5 shall each be tested every 8,760 hours of operation and at least once every five years.

Each engine shall be tested every 8,760 hours of operation and at least once every five years.

(4) Total plant emissions shall be the sum of emissions from each of the engines and boilers. The emission rates to be used in the equations listed in conditions 1 and 2 above shall be derived from the most recent stack test results. Power production rates shall be determined by Watt Hour meters on each of the engine and boiler generators. The total amount of kilowatt-hours generated by each engine or boiler shall be recorded on both a daily and a monthly basis.

e. SPRINGVILLE CITY CORPORATION

(1) (a) NO_X emissions from the operation of all engines at the plant shall not exceed 1.68 tons per day.

(b) NO_X emissions from the operation of all engines at the plant shall not exceed 248 tons per 12-month period.

(2) Compliance with the above limitations shall be determined by a continuous emissions monitoring system (CEM) meeting the requirements of R307-170. Daily NO_X emissions shall be calculated for each individual engine and summed into a monthly output. The monthly outputs shall be summed into a rolling 12-month total of NO_X in tons/year. The owner/operator shall calculate a new 12-month total by the last day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation.

IX.H.4. Establishment of Alternative Requirements

a. Alternative Requirements.

In lieu of the requirements imposed pursuant to Subsections IX.H.1**, 2 and 3** above, a facility owner may comply with alternative requirements, provided the requirements are established pursuant to the permit issuance, renewal, or significant permit revision process found in R307-415 and are consistent with the streamlining procedures and guidelines set forth in Subsections b and c below. These procedures and guidelines are drawn from section II.A. of EPA's *White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program*, dated March 5, 1996.

For the sources subject to R307-415, an alternative requirement is approved for the source by the executive secretary and the EPA if it is incorporated in an issued part 70 permit to which EPA has not objected. Any public comments concerning the alternative will be transmitted to EPA with the proposed permit. The executive secretary's determination of approval is not binding on the EPA.

Noncompliance with an alternative requirement approved under this plan shall constitute a violation of the underlying SIP condition that was established in Subsections IX.H.1**, 2 or 3** of this plan.

b. Demonstrating Equivalency of an Alternative Requirement.

The source shall demonstrate that the alternative requirement is as or more stringent than the existing SIP requirement, considering, among other things, the following:

(1) For emission limits:

(a) Emission limits should be converted to a common format/units of measure so that a direct comparison can be made. If not, a valid, detailed correlation must be demonstrated between different formats/units so that a comparison is possible.

(b) Are compliance dates as or more stringent (earlier or more frequent)?

(c) Are averaging times as or more stringent?

(d) Are transfer or collection efficiencies as or more stringent?

(e) Will the same pollutants be regulated to the same or greater extent?

(f) Are any exceptions/defenses as or more limited?

(g) Are associated test methods as or more stringent?

(2) For work practice standards:

(a) Are base elements the same (e.g., if the original rule addresses frequency of inspection and recordkeeping, does the new rule address these same elements?) and are requirements relating to these elements as or more stringent?

(b) The comparison should be for each individual emissions unit. The comparison should not analyze across multiple emissions units.

(c) Are compliance dates as or more stringent (earlier or more frequent)?

(d) Are averaging times, if any, as or more stringent?

(e) Will the same pollutants be regulated to the same extent?

(f) Are any exceptions/defenses as or more limited?

(3) For monitoring requirements/test methods:

(a) Would alternative monitoring assure compliance to the same or greater degree?

(b) Is the monitoring frequency the same or greater?

(c) Is the monitoring method as or more accurate, precise, reliable, and replicable?

(d) Is there sufficient evidence of the alternative method's accuracy/reliability?

(e) Are any exceptions to requirements as or more limited?

(f) Are quality assurance procedures as or more robust?

(4) For reporting requirements:

(a) Is the reporting frequency the same or more frequent?

(b) Are the reporting requirements the same or more detailed?

(c) Are the deadlines for reporting the same or more frequent?

(5) For record keeping requirements:

(a) Are the record keeping requirements the same or more detailed?

(b) Are the retention requirements as or more stringent?

(c) Are the requirements/methods as or more reliable?

If the source fails to demonstrate that the proposed alternative is as or more stringent than the provision to be replaced, the executive secretary shall disapprove the proposed alternative.

c. Procedure.

(1) A source can request an equivalent emission limitation or other requirement by submitting the following information to the executive secretary.

(a) Side-by-side comparison of existing and proposed requirements for specific emissions units of the source.

(b) A proposed written determination regarding relative stringency in accordance with Subsection b above, including documentation to support the determination. This shall be repeated for each emissions unit-pollutant combination.

(2) The source shall comply with the existing SIP limitation or requirement until the new limitation or requirement has been included in the source's operating permit and becomes effective. If the source won't be able to immediately comply with the new limitation or requirement, the source shall comply with existing limits/requirements until the new limits/requirements become effective.

(3) If the executive secretary disapproves the requested changes, the existing requirements remain in place. If EPA objects to the requested changes in accordance with R307-415-8, the existing requirements remain in place.

(4) At the time the executive secretary transmits a source's part 70 application to EPA, the executive secretary will notify EPA if a source has requested an equivalent emission limitation. The executive secretary will review the request, and if the executive secretary agrees that the source has demonstrated that the alternative requirement is as or more stringent that the existing SIP requirement, the executive secretary will submit the equivalent demonstration and supporting documentation to EPA in advance of draft permit issuance. If the executive secretary disapproves the requested changes, the disapproval notice will be submitted to EPA.

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

d. All emission limitations listed in Subsections IX.H.12 and IX.H.13 apply during steady-state operation, unless otherwise specified in the source specific conditions listed in IX.H.12 and 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 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. PM_{10}: 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 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.

      D. $PM_{2.5}$: 40 CFR 51, Appendix M, 201a and 202, or other EPA approved testing methods acceptable to the Director. The back half condensables shall be used for compliance demonstration as well as for inventory purposes. If a method other than 201a is used, the portion of the front half of the catch considered $PM_{2.5}$ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

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

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

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

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

I. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. 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 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.

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

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 $PM_{2.5}$ emissions as appropriate.

ii. Limits on Refinery Fuel Gas.

A. By no later than January 1, 2015, 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 no later than January 1, 2015. 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 no later than January 1, 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 Subpart Ja.

B. By no later than January 1, 2019, all major source petroleum refineries in or affecting a designated $PM_{2.5}$ non-attainment 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.

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. 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 Executive Secretary, 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 Sections 172(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 Order 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 PM2.5 Nonattainment Area

a. ATK Launch Systems Inc. – Promontory

i. During the period November 1 to February 28/29 on days when the 24-hour average $PM_{2.5}$ levels exceed 35 ug/m^3at 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 $PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ level exceeds 35 ug/m^3 at the nearest real-time monitoring station provided notice is given to the Director of the Utah Air Quality Division. No additional tests of rocket motors less than 1,000,000 lbs. of propellant may be conducted during the inversion period until the 24-hour average $PM_{2.5}$ level has returned to a concentration below 35 ug/m^3 at the nearest real-time monitoring station.

C. During this period, records will be maintained identifying the size of the rocket motors tested and the 24-hour average $PM_{2.5}$ level at the nearest real-time monitoring station on days when motor testing occur

iv. 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.

II. 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 NO_x emission rate is no greater than 30 ppm.

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

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 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 $PM_{2.5}$ from the Catalyst Regeneration System. At that time the condensable fraction will be added and a new source-wide limitation shall be established in the AO.

$PM_{2.5}$ 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 $PM_{2.5}$ emissions from the Catalyst Regeneration System shall be calculated using the following equation:

E = FR * EF

Where:
E = Emitted $PM_{2.5}$
FR = Feed Rate to Unit (kbbls/day)
EF = emission factor (lbs/kbbl), established by most recent stack test

Total 24-hour filterable $PM_{2.5}$ emissions shall be calculated by adding the results of the above filterable $PM_{2.5}$ 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

By no later than January 1, 2019, combined emissions of NO_X shall not exceed 0.80 tons per day (tpd) and 195 tons per rolling 12-month period.

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

NO_X = (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 NO_X CEM

Total daily NO_X emissions shall be calculated by adding the results of the above NO_X equations for natural gas and plant gas combustion to the estimate for the 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
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.

SO_2 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 SO_2/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 H_2S content of the fuel gas in ppmv. Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

Emission Factor (lb SO_2/MMscf gas) = [(24 hr avg. ppmv H_2S)/10^6]*(64 lb SO_2/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 SO_2 emission from the Catalyst Regeneration System shall be calculated using the following equation:

SO_2 = 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 SO_2 CEM

Total daily SO_2 emissions shall be calculated by adding the daily results of the above SO_2 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 H_2S (averaged for each day), all meter readings (in the appropriate units), and the calculated emissions.

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 testing as outlined in Section IX Part H.11.e of this SIP. 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. CER Generation II, LLC (Exelon Generation): West Valley Power Plant.

i. Emissions of NO_X from each individual turbine shall be no greater than 5 ppmdv (15% O_2, dry) based on a 30-day rolling average.

ii. Total emissions of NO_X from all five turbines shall be no greater than 37 lbs/hour (15% O_2, dry) based on a 30-day rolling average.

iii. The NO_X emission rate (lb/hr) shall be calculated by multiplying the NO_X 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.

e. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

NO_X 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.

NO_X 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)
NO_X	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)
NO_X	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.

f. Chemical Lime Company (LHoist North America).

i. Lime Production Kiln:

A. Upon plant start-up SNCR technology shall be installed on the Lime Production Kiln for reduction of NO_X 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 NO_x reduction is effective, and (b) no ammonia or urea injection during shutdown.

g. Chevron Products Company - Salt Lake Refinery

i. Source-wide $PM_{2.5}$

By no later than January 1, 2019, combined emissions of filterable $PM_{2.5}$ shall not exceed 0.18 tons per day (tpd) and 65 tons per rolling 12-month period.

Compliance with the daily $PM_{2.5}$ 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.

$PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ 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 NO_X

By no later than January 1, 2019, combined emissions of NO_X shall not exceed 2.1 tons per day (tpd) and 766.5 tons per rolling 12-month period.

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 NO_X 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 SO_2

By no later than January 1, 2019, combined emissions of SO_2 shall not exceed 1.05 tons per day (tpd) and 383.3 tons per rolling 12-month period.

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

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.

h. Great Salt Lake Minerals Corporation: Production Plant

NO_X 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. PM_{10} 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 $PM_{2.5}$ emission limit in grains/dscf and pounds/hour is proposed.

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

iii. PM_{10} 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 $PM_{2.5}$ 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.

i. 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.

j. 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.

k. HollyFrontier Corporation: Holly Refining and Marketing Company – Woods Cross L.L.C. (Holly Refinery)

i. Source-wide $PM_{2.5}$

By no later than January 1, 2019, $PM_{2.5}$ emissions (filterable + condensable) from all combustion sources shall not exceed 47.6 tons per rolling 12-month period and 0.134 tons per day (tpd).

$PM_{2.5}$ 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 $PM_{2.5}$/MMscf
Natural gas or Plant gas for all NSPS combustion equipment: 0.52 lb $PM_{2.5}$/MMscf

Fuel oil: The filterable $PM_{2.5}$ emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

$PM_{2.5}$ (lb/1000 gal) = (10 * wt. % S) + 3.22

The condensable $PM_{2.5}$ 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 $PM_{2.5}$ emissions for the emission points shall be calculated by adding the daily results of the above $PM_{2.5}$ 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 NO_X

By no later than January 1, 2019, NO_X 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).

NO_X 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 NO_X burners (LNB): 41 lbs/MMscf Natural gas/refinery fuel gas combusted using Ultra-Low NO_X burners: 0.04 lbs/MMbtu Natural gas/refinery fuel gas combusted using Next Generation Ultra Low NO_X 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 NO_X emissions for emission points shall be calculated by adding the results of the above NO_X equations for plant gas, fuel oil, and natural gas combustion. Results shall be 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 SO_2

By no later than January 1, 2019, the emission of SO_2 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).

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.

SO_2 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. SO_2 emission factors for the various fuels shall be as follows:

Natural gas - 0.60 lb SO_2/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 H_2S content of the fuel gas in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

(lb SO_2/MMscf gas) = (24 hr avg. ppmv H_2S)/10^6 * (64 lb SO_2/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 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. 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 SO_2 emissions shall be calculated by adding daily results of the above SO_2 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 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.

l. 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.

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

I. 6,205 tons of NO_X, $PM_{2.5}$ and SO_2 combined per rolling 12-month period until January 1, 2019.

II. After January 1, 2019, combined emissions of NO_X, $PM_{2.5}$, and SO_2 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]

C. 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 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.

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

I. KUC shall reduce emissions of combined $PM_{2.5}$, SO_x and NO_x 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.

m. Kennecott Utah Copper: Power Plant

i. UTAH POWER PLANT

A. 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 shall not exceed the following emission rates to the atmosphere:

POLLUTANT	lb/hr	ppmdv (15% O2 ddry)
I. NO_x:		2.0*
II. VOC:		2.0*
III. $PM_{2.5}$ with duct firing: Filterable + condensable	18.8	

* Under steady state operation.

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

POLLUTANT	TEST FREQUENCY
I. $PM_{2.5}$	3 years
II. NO_X	3 years
III. VOC	3 years

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

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% O^2)

68°F, 29.92 in. Hg

1. Before January 1, 2018

   a. $PM_{2.5}$

filterable	0.004
filterable + condensable	0.03

   b. NO_x: 336

2. After January 1, 2018

   a. $PM_{2.5}$

filterable	0.004
filterable + condensable	0.03

   b. NO_x: 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% O_2)
1. $PM_{2.5}$			
filterable	0.029	33.5	
filterable + condensable	0.29	382	
2. NO_x			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. $PM_{2.5}$	every year
2. NO_x	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.

ii. BONNEVILLE BORROW AREA PLANT

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

n. Kennecott Utah Copper: Smelter and Refinery.

i. SMELTER:

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

I. Main Stack (Stack No. 11)

1. $PM_{2.5}$
   a. 85 lbs/hr (filterable)
   b. 434 lbs/hr (filterable + condensable)

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

3. NO_X 35 lbs/hr (annual average)

II. Acid Plant Tail Gas

1. SO_2
   a. 1,050 ppmdv (3 hr. rolling average)
   b. 650 ppmdv (6 hr. rolling average)

III. 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)	PM2.5	Every Year
	SO2	CEM
	NOx	CEM
II. Acid Plant Tailgas	SO2	CEM

III. 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. 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. 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.

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

iii. 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	NO_X	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	NO_X	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.

b. 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. $PM_{2.5}$
1. 17.4 lbs/hr (24 hr. average filterable)
2. 29.53 lbs/hr (condensable)

II. SO_2
1. 93.98 lbs/hr (3 hr. rolling average)
2. 89.0 lbs/hr (daily average)

III. NO_X 59.75 lbs/hr (12-month rolling average)

IV. VOC 22.20 lbs/hr

B. Reheat Furnace

#1 NO_X 15.0

lb/hr

C. Reheat Furnace #2

NO_X 8.0 lb/hr

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

EMISSION POINT	POLLUTANT	TEST FREQUENCY
A. Electric Arc Furnace Baghouse	$PM_{2.5}$	every year
	SO_2	CEM
	NO	CEM
	VOC	every 5 years
B. Reheat Furnace #1	NO_X	every 3 years
C. Reheat Furnace #2	NO_X	every 3 years

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 SO_2 and NO_x of Condition (i)(A) above, Nucor shall calibrate, maintain and operate the measurement systems for continuously monitoring for SO_2 and NO_x 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 $PM_{2.5}$ 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 $PM_{2.5}$ limit, that will constitute compliance with the $PM_{2.5}$ limit. If TSP emissions are not below the $PM_{2.5}$ limit, the owner/operator shall retest using EPA approved methods specified for $PM_{2.5}$ testing, within 120 days.

C. Startup/shutdown NO_x and SO_2 emissions are monitored by CEMS.

p. Olympia Sales Company: Cabinet Manufacturing Facility

i. By January 1, 2015, a baghouse control device shall be 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, door, and sanding areas shall be exhausted through the baghouse during startup, shutdown, and normal operations of the plant.

q. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

A. Emissions of NO_X shall be no greater than 336 ppmdv (3% O_2, dry).

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors to determine compliance with the NO_X limitation.

ii. Steam Generating Unit #2:

A. Emissions of NO_X shall be no greater than 336 ppmdv (3% O_2, dry).

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors to determine compliance with the NO_X limitation.

iii. Steam Generating Unit #3:

A. Emissions of NO_X shall be no greater than 336 ppmdv (3% O_2, dry).

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors to determine compliance with the NO_X limitation.

iv. Natural Gas-fired Simple Cycle Turbine Units:

A. Total emissions of NO_X from all three turbines shall be no greater than 22.2 lbs/hour (15% O_2, dry) based on a 30-day rolling average.

B. Emission of NO_X from each individual turbine shall be no greater than 5 ppmdv (15% O_2, 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 NO_X and O_2 monitors to determine compliance with the applicable NO_X limitations. The NO_X emission rate (lb/hr) shall be calculated by multiplying the NO_X 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.

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

i. Source-wide $PM_{2.5}$

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.

$PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ (filterable + condensable) emissions shall be calculated by adding the results of the above filterable $PM_{2.5}$ 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 NO_X

By no later than January 1, 2019, combined emissions of NO_X shall not exceed 1.988 tons per day (tpd) and 475 tons per rolling 12-month period.

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 NO_X CEM shall be used to calculate daily NO_X emissions from the FCCU wet gas scrubber stack. Emissions shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by the mass flow of the flue gas. The NO_X 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 NO_X 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 SO_2

By no later than January 1, 2019, combined emissions of SO_2 shall not exceed 3.1 tons per day (tpd) and 300 tons per rolling 12-month period.

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.

Daily SO_2 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 H_2S measurement or from the SO_2 measurement obtained by direct testing/monitoring.

The emission factor, where appropriate, 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.

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

s. 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
NO_x	3%	3.3

Source: Paper Machines Process Stacks (Each)

Pollutant	lb/hr
PM_{10}	6.65
$PM_{2.5}$	to be determined

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 $PM_{2.5}$. At that time the condensable fraction will be added and a $PM_{2.5}$ limit established in the AO.

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

t. 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. Boilers #3	NO_X	187
B. Boilers #4a & 4b	NO_X	9
C. Boilers #5a & 5b	NO_X	9
D. Turbine	NO_X	9
E. Turbine and WHRU Duct burner	NO_X	15

ii. Stack 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. Boilers #3	NO_X	*	every 3 years
B. Boilers #4a & #4b	NO_X	2018	every 3 years
C. Boilers #5a & #5b	NO_X	2017	every 3 years
D. Turbine	NO_X	2014	every year
E. Turbine and WHRU Duct Burner	NO_X	2014	every year

* Initial test already performed

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 NO_X 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

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

u. Vulcraft / Nucor Building Systems

i. R307-350 Miscellaneous Metal Parts and Products Coatings applies to the painting operations a t 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

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

ii. Emissions of NO_X from the Municipal Waste Combustors shall not exceed 350 ppmdv (7% O_2, dry), based on a daily arithmetic average concentration.

iii. Compliance shall be determined by CEMs.

iv. 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.

v. 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.

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.

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

EMISSION POINT	POLLUTANT	ppmdv (3% O_2 dry)
A. Unit #1	NO_X	36 ppm
B. Unit #4	NO_X	36 ppm
C. Unit #6	NO_X	36 ppm

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 #4	NO_X	January 1, 2017	every three years
C. Unit #6	NO_X	January 1, 2017	every three years

* 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.

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.

b. Geneva Nitrogen Inc.: Geneva Nitrogen Plant

i. Prill Tower:

PM_{10} emissions shall not exceed 0.22 ton/day and 79 ton/yr

ii. Testing

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.

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:

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

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 NO_X 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.

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

I. Measurement Approach: NO_X concentration (ppmdv) shall be determined by using a NO_X CEM.

II. Indicator Range: An excursion is defined as a one-hour average NO_X 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. 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. PacifiCorp Energy: Lake Side Power Plant

i. Block #1 Turbine/HRSG Stacks:

Emissions of NO_X shall not exceed 2.0 ppmvd (15% O_2) on a 3-hour average basis.

ii. Block #2 Turbine/HRSG Stacks:

Emissions of NO_X shall not exceed 2.0 ppmvd (15% O_2) on a 3-hour average basis.

iii. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors to determine compliance with the applicable NO_X limitations.

iv. 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 ppmvd emission limits listed in IX.H.13.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% O2. 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.

d. Pacific States Cast Iron Pipe Company: Pipe Casting Plant

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. The Annealing Oven furnaces are limited to 63.29 MMBtu/hr.

iii. Emissions from the desulfurization and ductile treatment system shall be routed through the operating baghouse
prior to be emitted into the atmosphere.

iv. Emissions from the Special Lining Shotblast operations shall be routed through the operating baghouse prior to being emitted into the atmosphere.

e. Payson City Corporation: Payson City Power

i. Emissions of NO_X shall be no greater than 1.54 ton per day and 268 tons per rolling 12-month period for all engines combined.

ii. Compliance with the emission limitation shall be determined by 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.

f. Provo City Power: Power Plant

i. Emissions of NO_X 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 NO_X 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. NO_X 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.

g. Springville City Corporation: Whitehead Power Plant

i. Emissions of NO_X 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 NO_X 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.