Air Quality
PERMIT TO CONSTRUCT
State of Idaho
Department of Environmental Quality

PERMIT No.: P-2008.0066
FACILITY ID No.: 077-00029
AQCR: 61 CLASS: A ZONE: 12
SIC: 2873/2819 NAICS: 325311
UTM COORDINATE (km): 344.1, 4,735.4

1. **PERMITTEE**
Southeast Idaho Energy, LLC

2. **PROJECT**
Initial PTC, Power County Advanced Energy Center

3. **MAILING ADDRESS**	**CITY**	**STATE**	**ZIP**
621 17th Street, Suite 1640	Denver	CO	80293

4. **FACILITY CONTACT**	**TITLE**	**TELEPHONE**
Tom Hornyak	Manager, Environmental Permitting	303.953.4297 t.hornyak@rehinc.com

5. **RESPONSIBLE OFFICIAL**	**TITLE**	**TELEPHONE**
Matt Lee	Executive Vice President	303.953.4333 m.lee@rehinc.com

6. **EXACT PLANT LOCATION**	**COUNTY**
Lamb Weston Road, American Falls, Idaho 83211	Power

7. **GENERAL NATURE OF BUSINESS & KINDS OF PRODUCTS**
Coal/petcoke gasification to produce agricultural fertilizer products

8. **PERMIT AUTHORITY**

This permit is issued according to the Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01.200 through 228, and pertains only to emissions of air contaminants regulated by the state of Idaho and to the sources specifically allowed to be constructed or modified by this permit.

This permit (a) does not affect the title of the premises upon which the equipment is to be located; (b) does not release the permittee from any liability for any loss due to damage to person or property caused by, resulting from, or arising out of the design, installation, maintenance, or operation of the proposed equipment; (c) does not release the permittee from compliance with other applicable federal, state, tribal, or local laws, regulations, or ordinances; (d) in no manner implies or suggests that the Department of Environmental Quality (DEQ) or its officers, agents, or employees, assume any liability, directly or indirectly, for any loss due to damage to person or property caused by, resulting from, or arising out of design, installation, maintenance, or operation of the proposed equipment.

This permit will expire if construction has not begun within two years of its issue date or if construction is suspended for one year.

This permit has been granted on the basis of design information presented with its application. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

CHERYL A. ROBINSON, P.E., PERMIT WRITER
DEPARTMENT OF ENVIRONMENTAL QUALITY

DATE MODIFIED/REVISED:	
DATE ISSUED:	**PUBLIC COMMENT**

MIKE SIMON, STATIONARY SOURCE PROGRAM MANAGER
DEPARTMENT OF ENVIRONMENTAL QUALITY

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Acronyms, Units, and Chemical Nomenclature

acfm	actual cubic feet per minute
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AN	ammonium nitrate
AQCR	Air Quality Control Region
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
Btu	British thermal unit
CAA	Clean Air Act
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
CI ICE	compression-ignition internal combustion engine (i.e., a diesel engine)
CO	carbon monoxide
CO_2	carbon dioxide
COMS	continuous opacity monitoring system
COS	carbonyl sulfide
DEQ	Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
^oF	degrees Fahrenheit
FGR	flue gas recirculation
GE	GE Energy
gpm	gallons per minute
g/dscm	grams per dry standard cubic meter
gr/dscf	grain (1 lb = 7,000 grains) per dry standard cubic foot
H_2	hydrogen
H_2S	hydrogen sulfide
HAPs	hazardous air pollutants
Hg	mercury
hp	horsepower
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
K	degrees Kelvin
km	kilometer
kW	kilowatt
lb/hr	pound per hour
m	meter(s)
m/sec	meters per second
MACT	Maximum Achievable Control Technology
$\mu g/m^3$	micrograms per cubic meter
MMBtu	million British thermal units
MMscf	million standard cubic feet
MW or MW_e	megawatts of electrical output
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
ng/J	nanograms per Joule
NH_3	ammonia
NMHC	nonmethane hydrocarbons
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards

Acronyms, Abbreviations, and Chemical Nomenclature, continued

O_2	oxygen
O&M	Operations & Maintenance
PCAEC	Power County Advanced Energy Center
PEMS	predictive emission monitoring system
petcoke	petroleum coke
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
ppmv	parts per million by volume
PSA	pressure swing adsorber
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psig	pounds per square inch gauge
PTC	permit to construct
PTE	potential to emit
scf	standard cubic feet
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIE	Southeast Idaho Energy, LLC
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
SRC##	emission source number
SSM	Startup, Shutdown, and Scheduled Maintenance Plan
TBD	to be determined
TPD	tons per calendar day
TPH	tons per hour
TPY	tons per any 12 consecutive calendar months
UTM	Universal Transverse Mercator
VOC	volatile organic compound
WSA	wet gas sulfuric acid (process)
ZLDS	zero liquid discharge system

1. PERMIT TO CONSTRUCT SCOPE

Purpose

1.1 This permit to construct (PTC) is for initial construction of Southeast Idaho Energy's (SIE) Power County Advanced Energy Center (PCAEC). The primary processes at this facility are gasification of coal and petcoke feedstocks to produce ammonia, urea, and urea ammonium nitrate (UAN) for sale. Saleable byproducts from the processes include slag or frit from the gasifiers, and either elemental sulfur or sulfuric acid from equipment used to control sulfur emissions from the synthetic gas cleanup train.

1.2 This is the initial permit to construct for this facility.

Regulated Sources

1.3 Table 1.1 lists all sources of regulated emissions in this PTC.

Table 1.1 SUMMARY OF REGULATED SOURCES

Permit Section	Source Description	Emissions Control(s)
3	Coal, Petcoke, and Fluxant Storage and Handling	Enclosures Baghouses Covered Conveyors Water Sprays or equivalent (fluxant only)
4	Natural Gas-Fired Heaters ASU Regen Heater Gasifier Heaters #1 and #2	None
5	Diesel-fired Emergency Generators 2 MW Emergency Generator 500 kW Emergency Generator (Fire Pump)	None
6	Package Boiler and Steam Superheater Boiler	Low-NOx burner & FGR (Package Boiler) Low-NOx burner & SCR (Steam Superheater Boiler)
7	Gasification Island	<u>Startups:</u> Sour Water Scrubber Activated Carbon Beds Amine Scrubber Gasifier Flare <u>Normal Operations:</u> Sour Water Scrubber Activated Carbon Beds AGR Stream 1: Option #1: Claus Sulfur Recovery Unit Option #2: Haldor-Topsoe Wet Sulfuric Acid Plant AGR Stream 2: Thermal Oxidizer AGR Stream 3: None
8	Ammonia and Urea Plants (purge gases)	Process Flare
8	Urea Melt Plant Vent Stack	None
8	Urea Granulation	Wet scrubber
9	Nitric Acid Plant, tailgas	SCR
9	Ammonium Nitrate/ UAN Plant	None

Table 1.1 SUMMARY OF REGULATED SOURCES

Permit Section	Source Description	Emissions Control(s)
10	Diesel, Acid, and UAN Tank Storage	None
10	Ammonia Tank Storage	Ammonia Storage Flare
11	ZLDS and Cooling Tower	Drift/mist eliminators
12	Slag Storage and handling	3-sided bunker
12	Granular urea storage, Humidity-controlled warehouse storage	None
12	Elemental sulfur storage	None

2. FACILITY-WIDE CONDITIONS

Definitions

2.1 For the purposes of this permit, the following terms used in this permit shall be defined as follows:

2.1.1 ***Commencement of operations***, for the purposes of determining when a Tier I application must be submitted in accordance with IDAPA 58.01.01.313.01.b, means the earliest initial startup date for any emission source at the facility.

2.1.2 ***Malfunction*** is defined in 40 CFR 60.2 for NSPS purposes, and means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions. *Malfunction* shall have the same meaning when used for any other purpose in this permit.

2.1.3 ***Startup (Initial)*** is defined in 40 CFR 60.2 for the purposes of NSPS notification, reporting, and performance testing, and means the first time that an affected facility is set in operation for any purpose. *Initial startup* of any unit has the same meaning for the purpose of submitting required plans or procedures to DEQ.

2.1.4 ***Startup*** is defined in IDAPA 58.01.01.006, and means the normal and customary time period required to bring air pollution control equipment or an emission unit, including process equipment, from a nonoperational status into normal operation.

Emissions of Hazardous Air Pollutants

2.2 Emissions of Hazardous Air Pollutants (HAPs) from the entire PCAEC facility shall not equal or exceed:

- 8.0 tons of any HAP during any consecutive 12-calendar month period, and
- 20.0 tons of all HAPs during any consecutive 12-calendar month period.

Operations & Maintenance (O&M) Manual

2.3 **At least 60 days before initial start-up of each pollution control device**, the permittee shall have developed and submitted to DEQ **for review and comment** an Operations and Maintenance (O&M) manual that describes the procedures that will be followed to comply with General Provision 2 of this permit and the manufacturer specifications for these air pollution control devices:

- Baghouses used to control particulate emissions from rail unloading, handling, and storage of feedstocks. If bag leak deterction systems are not provided, the O&M manual shall contain requirements for **monthly** see/no see visible emissions inspections of the baghouse(s). The inspection(s) shall occur during daylight hours and under normal operating conditions. Visible emissions inspections for silo baghouses shall be conducted while material is being transferred at normal operating rates into the silo(s). If bag leak detection systems are used, the manual shall include appropriate provisions for inspection, maintenance, and testing of these systems.

- Fluxant water spray system(s) (if used);
- Flue gas recirculation (FGR) system for reducing NO_x from the package boiler;
- Selective catalytic reduction (SCR) system for reducing NO_x from the steam superheater boiler;
- Sour water scrubber for removing trace metals and sulfides from the syngas;
- Activated carbon beds for removing mercury from the syngas;
- Sulfur Control Unit used to control H_2S emissions from the acid gas removal (AGR) unit:
  - Operating Scenario #1: Claus Sulfur Recovery Unit.
  - Operating Scenario #2: Haldor-Topsoe wet sulfuric acid plant, including the:
    - Tailgas scrubbing system, and
    - SCR system.
- SCR system serving the nitric acid plant;
- Amine scrubber used to decrease sulfur compounds in the syngas prior to flaring in the Gasifier Flare;
- Flares, including the:
  - Gasifier flare,
  - Ammonia storage flare, and the
  - Process flare serving the ammonia and urea production plants.
- Thermal oxidizer used to treat remaining H_2S and COS in the CO_2-rich stream from the AGR (AGR Stream 2); and the
- Urea granulation process scrubber.

2.4 The O&M manual, or if submitted in sections, each O&M submittal, shall contain a certification by a responsible official. Any changes to the manual shall be submitted to DEQ for **review and comment** within 15 days of the change. The O&M manual shall remain on site at all times and shall be made available to DEQ representatives upon request. At a minimum the following items shall be included in the manual:

- The manufacturer's recommended minimum (and, if necessary, maximum) values that shall be maintained for any of the operating parameters required to be monitored during performance testing, as listed in the applicable section of this permit.
- The scheduled frequency for routine inspection, maintenance, and routine repair/replacement.
- Parameters to be addressed during inspections and routine maintenance, and indicators signaling that the equipment should be repaired or replaced.
- Parameters that will be documented for inspections, maintenance, and corrective actions. The permittee shall maintain records of the results of inspections in accordance with General Provision 7.

The operating and monitoring requirements specified in the O&M manual are incorporated by reference to this permit and are enforceable permit conditions.

Fugitive Emissions

2.5 All reasonable precautions shall be taken to prevent fugitive dust from becoming airborne in accordance with IDAPA 58.01.01.650-651. In determining what is reasonable, consideration will be given to factors such as the proximity of dust-emitting operations to human habitations and/or activities and atmospheric conditions that might affect the movement of particulate matter.

2.5.1 Some of the reasonable precautions include, but are not limited to, the following, where practical:

- Use of Water or Chemicals. Use, where practical of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land.
- Application of Dust Suppressants. Application, where practical, of asphalt, oil, water, or suitable chemicals to, or covering of, dirt roads, material stockpiles, and other surfaces which can create dust.
- Use of Control Equipment. Installation and use, where practical, of hoods, fans, fabric filters, or equivalent systems to enclose and vent the handling of dusty materials. Adequate containment methods should be employed during sandblasting or other operations.
- Covering of Trucks. Covering, where practical, open bodied trucks transporting materials likely to give rise to airborne dusts.
- Paving. Paving of roadways and their maintenance in a clean condition, where practical.
- Removal of Materials. Prompt removal of earth or other stored material from streets, where practical.

2.5.2 The permittee shall monitor and maintain records of the frequency and the method(s) used (e.g., water, chemical dust suppressants) to reasonably control fugitive dust emissions.

2.5.3 The permittee shall conduct a **quarterly** facility-wide inspection of potential sources of fugitive emissions, during daylight hours and under normal operating conditions to ensure that the methods used to reasonably control fugitive emissions are effective. If fugitive emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee shall maintain records of the results of each fugitive emissions inspection. The records shall include, at a minimum, the date of each inspection and a description of the following: the permittee's assessment of the conditions existing at the time fugitive emissions were present (if observed), any corrective action taken in response to the fugitive emissions, and the date the corrective action was taken.

2.5.4 The permittee shall maintain records of all fugitive dust complaints received. The permittee shall take appropriate corrective action as expeditiously as practicable. The records shall include, at a minimum, the date that each complaint was received and a description of the following: the complaint, any corrective action taken, and the date the corrective action was taken.

Visible Emissions (Opacity)

2.6 The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined by procedures contained in IDAPA 58.01.01.625. These provisions shall not apply when the presence of uncombined water, nitrogen oxides, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this section

The permittee shall conduct a **monthly** facility-wide inspection of potential sources of visible emissions, during daylight hours and under normal operating conditions. Visible emissions inspections for silo baghouses shall be conducted while material is being transferred at normal operating rates into the silo(s). Visible emissions inspections are not required for any baghouse stack if the baghouse is equipped with a bag leak detection system that provides continuous monitoring for baghouse performance.

2.7 The visible emissions inspection shall consist of a see/no see evaluation for each potential source. If any visible emissions are present from any point of emission, the permittee shall either take appropriate corrective action as expeditiously as practicable, or perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is greater than 20% for a period or periods aggregating more than three minutes in any 60-minute period, the permittee shall take all necessary corrective action and report the exceedance in accordance with IDAPA 58.01.01.130-136. The permittee shall maintain records of the results of each visible emissions inspection and each opacity test when conducted. The records shall include, at a minimum, the date and results of each inspection and test and a description of the following: the permittee's assessment of the conditions existing at the time visible emissions are present (if observed), any corrective action taken in response to the visible emissions, and the date corrective action was taken.

Odors

2.8 The permittee shall not allow, suffer, cause, or permit the emission of odorous gases, liquids, or solids to the atmosphere from the PCAEC in such quantities as to cause air pollution.

2.9 The permittee shall maintain records of all odor complaints received. The permittee shall take appropriate corrective action as expeditiously as practicable. The records shall include, at a minimum, the date that each complaint was received and a description of the following: the complaint, any corrective action taken, and the date the corrective action was taken.

Open Burning

2.10 The permittee shall comply with the requirements of the Rules for Control of Open Burning, IDAPA 58.01.01.600-616.

Fuel-burning Equipment

2.11 In accordance with IDAPA 58.01.01.676 and 677, the permittee shall not discharge PM to the atmosphere from any fuel-burning equipment in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas fuels, 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for

liquid fuels, and for fuel-burning equipment with a maximum rated input of 10 MMBtu/hr or more, shall not discharge PM in excess of 0.050 gr/dscf of effluent gas corrected to 8% oxygen for coal.

Fuel Oil, Coal, and Petroleum Coke (Petcoke) Specifications

2.12 No person shall sell, distribute, use, or make available for use **for use in any fuel-burning source**, any of the following fuel containing more than the following percentages of sulfur (IDAPA 58.01.01.725-729):

- ASTM Grade 1 fuel oil - 0.3% by weight.
- ASTM Grade 2 fuel oil - 0.5% by weight.
- ASTM Grades 4, 5 and 6 fuel oil - 1.75% by weight.
- Any coal containing greater than 1.0% sulfur by weight.

2.13 Stationary Compression-Ignition (Diesel) Nonroad Engine Fuels (NSPS, Subpart IIII, 40 CFR 60.4207):

- Beginning October 1, 2007, for engines subject to 40 CFR 60 Subpart IIII, no person shall use any distillate fuel oil that contains more than 500 parts per million (0.05% by weight) of sulfur, and has either a cetane index less than 40 or a maximum aromatic content of 35 volume percent.
- Beginning October 1, 2010, for engines subject to 40 CFR 60 Subpart IIII and which have a displacement less than 30 liters per cylinder, no person shall use any distillate fuel oil that contains more than 15 parts per million (0.015% by weight) of sulfur, and has either a cetane index less than 40 or a maximum aromatic content of 35 volume percent.

2.14 The sulfur content of the coal, petcoke, and fluxant, as blended, shall not exceed 6.0% sulfur by weight on an as-received basis, except as modified by a performance test as specified in Permit Condition 7.4.

2.15 The permittee shall maintain documentation of supplier verification of fuel oil, coal, and petcoke sulfur content and fuel oil cetane index or maximum aromatic content on an as-received basis, and in accordance with General Provision 7.

Source Testing Outside Permit Requirements

2.16 The permittee may conduct source testing to evaluate changes to a process or control device including, but not limited to, a feed rate or production increase, change in feedstock parameters (e.g., sulfur content), or control device operational change, as follows:

- Each source test shall be conducted in accordance with a DEQ-approved test protocol and in accordance with IDAPA 58.01.01.157.
- If the source test results demonstrate an exceedance of an existing emissions limit, and excess emissions report must be submitted to DEQ.
- After conducting the test, the source:
  - Shall return to compliance with existing permit restrictions until the appropriate permitting action is taken to change the operational restrictions, if the source test results demonstrate an exceedance of an existing emissions limit; or
  - May continue to operate at the new operational parameters achieved during the source test, if the source test results demonstrate compliance with applicable existing emission limits.

New Tier I Source Requirement

2.17 In accordance with IDAPA 58.01.01.313.01.b, the permittee shall submit a complete application to DEQ for an initial Tier I operating permit within 12 months of becoming a Tier I source or commencing operation.

Reports and Certifications

2.18 Any reporting required by this permit shall comply with General Provision 9. Any reporting required by this permit shall be submitted to the DEQ Regional Office address shown in Table 2.2.

NSPS, 40 CFR 60 Subpart A – General Provisions

2.19 Generally applicable reporting, recordkeeping and notification requirements of Subpart A of the New Source Performance Standards (NSPS, 40 CFR 60) are included in Table 2.2. The summary for 40 CFR 60 Subpart A, as well as other NSPS summaries throughout this permit, are provided to highlight the NSPS notification and recordkeeping requirements for affected facilities, and are not intended to be a comprehensive listing of all general provisions requirements or specific requirements that may apply. Should there be a conflict between an NSPS summary and the NSPS, the NSPS shall govern. The permittee is encouraged to read all of 40 CFR 60 Subpart A. The CFRs are available on-line at: http://www.gpoaccess.gov/cfr/index.html.

TABLE 2.2 NSPS SUBPART A (40 CFR 60) SUMMARY OF GENERAL PROVISIONS FOR AFFECTED FACILITIES

Section	Section Title	Summary of Section Requirements
60.4	Address	All notifications and reports shall be submitted to: ***For non-delegated NSPS*** Director, Office of Air, Waste, and Toxics U.S. EPA 1200 Sixth Avenue, M/S OAQ-107 Seattle, WA 98101 & Air Quality Permit Compliance Department of Environmental Quality Pocatello Regional Office 444 Hospital Way #300 Pocatello, Idaho 83201 ***For delegated NSPS*** As of June 30, 2008, delegated NSPS relevant to the PCAEC are the following federal standards as in effect as of July 1, 2007: A, Db, G, H, J, Kb, Y, and IIII. Air Quality Permit Compliance Department of Environmental Quality Pocatello Regional Office 444 Hospital Way #300 Pocatello, Idaho 83201 For current delegation status go to: http://www.deq.idaho.gov/air/permits_forms/permitting/new_source.cfm

TABLE 2.2 NSPS SUBPART A (40 CFR 60) SUMMARY OF GENERAL PROVISIONS FOR AFFECTED FACILITIES

Section	Section Title	Summary of Section Requirements
60.7(b), (c),(d) and (f)	Notification and Record Keeping	• Notification of commencement of construction postmarked no later than 30 days of such date. • Notification of initial startup postmarked within 15 days of such date. • Notification of physical or operational change that may increase emissions postmarked 60 days before the change is made. • Maintain records of the occurrence and duration of any: startup, shutdown or malfunction of the affected source; malfunction of an air pollution control device; and any period when a continuous emissions monitoring system or monitoring device is inoperative. • For affected units with continuous emissions monitoring device requirements report excess emissions and monitoring system performance semiannually, postmarked by January 30th and July 30th (in the format required by NSPS). • Maintain in a permanent form records suitable for inspection of all measurements, system testing, performance measurements, calibration checks, and adjustments/maintenance performed. Records shall be maintained for a period of two years from the date the record is required to be generated by the applicable regulation. • Continuous emissions monitoring system (CEMS) record keeping requirements depending on whether data is automatically or manually recorded - 40 CFR 60.7(f).
60.8	Performance Tests	• The owner or operator shall provide notice at least 30 days prior to any performance test to afford an opportunity for an observer to be present during testing. • Within 60 days of achieving maximum production, but not later than 180 days after initial startup the permittee shall conduct performance test(s) and furnish a written report of the results of the test(s).
60.11(a),(b), (c), (d),and (g)	Compliance with Standards and Maintenance Requirements	• Other than opacity standards, where performance tests are required compliance with standards is determined by methods and procedures established by 40 CFR 60.8. • Compliance with NSPS opacity standards shall be determined by Method 9 of Appendix A. The owner or operator may elect to use continuous opacity monitoring system (COMS) measurements in lieu of Method 9 provided notification is made at least 30 days before the performance test. • At all times, including periods of startup, shutdown, and malfunction to the extent practicable, the operator shall maintain and operate any affected facility and air pollution control equipment consistent with good air pollution control practices. • For the purposes of determining compliance with standards any creditable evidence may be used if the appropriate performance or compliance test procedure has been performed.
60.12	Circumvention	No owner or operator shall build, erect, install or use any article or method, including dilution, to conceal an emission which would otherwise constitute a violation.
60.13	Monitoring Requirements	All COMS and CEMS shall conform to the reporting, calibration and data reduction requirements specified in detail by this section. Reporting requirements include submitting performance evaluations reports within 60 days of the evaluations required by this section, and submitting results of the performance evaluations for the COMS within 10 days before a performance test if using COMS to determine compliance with opacity during a performance test instead of Method 9 of Appendix A.

TABLE 2.2 NSPS SUBPART A (40 CFR 60) SUMMARY OF GENERAL PROVISIONS FOR AFFECTED FACILITIES

Section	Section Title	Summary of Section Requirements
60.14	Modification	• Physical or operational changes to source types that are regulated by a NSPS which result in an increase in hourly emissions to which a standard applies is considered a modification (unless expressly exempted the NSPS). Modified sources become subject to the NSPS standards • Note that in accordance with IDAPA 58.01.01.201 no owner or operator may commence a modification without first obtaining a permit to construct unless the modification is exempted from the need to obtain a permit in accordance with IDAPA 58.01.01.220-223.

NESHAP, 40 CFR 61 and 63, Reports and Notifications

2.20 Reports and notifications required by NESHAPs (40 CFR 61 and 63) for delegated and non-delegated standards are required to be submitted to both EPA and DEQ (67 FR 3106, 1/23/02). The permittee shall submit NESHAP reports and notifications to the EPA and to the DEQ Regional Office at the addresses provided in Table 2.2.

3. FEEDSTOCK STORAGE AND HANDLING

3.1 Process Description

Permit Conditions 3.1 and 3.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

Coal and petcoke will be delivered by rail in dedicated unit trains or manifest trains. A rotary dumper will be used to unload the feedstock from each railcar into an enclosed pit. From the pit, a belt feeder system will transfer coal/petcoke to an enclosed conveyor, which will transport the feedstock to storage silos or other covered storage technologies. The silos will be Eurosilo or similar technology, a covered fuel storage system that includes dust suppression equipment. Silo storage will be sized to provide a minimum of 30 days' worth of feedstock. The coal/petcoke will be delivered by conveyors from the silos to the coal grinding structure, then conveyed to the coal preparation area where it will be crushed or ground into smaller pieces. The crushed feedstock will be conveyed to milling equipment, which contains steel rods or equivalent technology to further break down the feedstock's particle size. Water and fluxant will be added during the milling process to produce a slurry, which will be pumped to a main slurry tank after having been screened to remove large particles. Particulate emissions from materials transfer, storage silo vents, conveyor transfer points, and coal and petcoke grinding and milling will be controlled by enclosures, using a rotary dumping system instead of a bottom dump system, and baghouses as described in Table 3.1.

Fluxant (typically limestone, silica/sand, or iron ore) will be received by truck or rail, and will be stored in an enclosed silo or other covered storage technology. Emissions from the fluxant storage silo vent(s) will be controlled by baghouse(s)/cartridge filter(s). The fluxant will be blended with the feedstock using a weight belt feeder system or equivalent technology. When it is not subject to freezing, water sprays will be used to control fugitive dust emissions from fluxant unloading, silo filling, and loading into the rod mill hopper. During freezing conditions, alternate methods for controlling these fugitive emissions will be used. Conveyors transferring fluxant will be covered and will have enclosed transition points.

3.2 Emissions Control Description

Table 3.1 FEEDSTOCK STORAGE AND HANDLING DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Fluxant Handling Railcar or Truck Unloading (fugitives) Hopper to Fluxant Silo(s) (fugitives and silo vent) Silo(s) to Rod Mill Hopper (fugitives)	Fully enclosed storage silo(s), with Silo vent baghouse/cartridge filter: Mfr/Model: TBD PM/PM_{10} Control: 99% Covered conveyor(s) with enclosed transition points. Water sprays or equivalent, minimum 75% control for fugitives.	Stack Parameters, Fluxant Silo Vent(s) Baghouse: Stack Height: TBD Exit Diameter: TBD Orientation: TBD Exit flow rate: TBD Exit Velocity: TBD Exit Temperature: Ambient

Table 3.1 FEEDSTOCK STORAGE AND HANDLING DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Coal and Petcoke Handling		
Railcar Unloading (SRC01) Manufacturer: TBD Model: TBD Max Capacity: 5,000 TPH max unloading rate Operations: 8,760 hr/yr	Rotary dumping system. Railcar unloading structure with restricted end door openings. Enclosure is at negative pressure during transfers. High-efficiency Baghouse: Mfr/Model: TBD PM/PM_{10} Control: 99%	Stack Parameters, SRC01: Stack Height: 10.0 m (32.8 ft) Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient
Railcar Hopper – Railcar Conveyor (SRC02) Railcar Conveyor to Silo Conveyors (SRC03) Silo Conveyor – Stacker Conveyors (SRC04) Manufacturer: TBD Model: TBD Max Capacity: 5,000 TPH max rate (each) Operations: 8,760 hr/yr (each)	Covered conveyors with enclosed transition points. High-efficiency Baghouse (each): Mfr/Model: TBD PM/ PM_{10} Control: 99%	Stack Parameters, SRC02, SRC03, and SRC04: Stack Height: 5.0 m (16.4 ft) (SRC02, SRC03) Stack Height: 2.0 m (6.6 ft) (SRC04) Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient
Coal and Petcoke Storage: Silos 1, 2, and 3 (SRC06, SRC07, and SRC05) Manufacturer: Eurosilo or equivalent Model: TBD Max Fill Rate: 5,000 TPH (each) Operations: 8,760 hr/yr (each)	Baghouses (1 for each silo): Mfr/Model: TBD PM/PM_{10} Control: 99%	Silo Vent Parameters SRC06, SRC07, SRC05: Vent Stack Height: 57.0 m Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient
Silo 1 Reclaimer to Reclaim Conveyor 1 (SRC08) Silo 2 Reclaimer to Reclaim Conveyor 2 (SRC09) Silo 3 Reclaimer to Reclaim Conveyor 3 (SRC10) Manufacturer: TBD Model: TBD Max Capacity: 105 TPH max unloading rate (each) Operations: 8,760 hr/yr (each)	Covered conveyors with enclosed transition points. Baghouses (1 for each reclaimer): Mfr/Model: TBD PM/PM_{10} Control: 99%	Stack Parameters: SRC08, SRC09, and SRC10 Stack Height: 53.0 m Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient
Reclaim Conveyor to Rod Mill Hopper #1 (SRC11) Reclaim Conveyor to Rod Mill Hopper #2 (SRC12) Manufacturer: TBD Model: TBD Max Capacity: 105 TPH max unloading rate (each) Operations: 8,760 hr/yr	Covered conveyors with enclosed transition points. Baghouses (1 for each hopper): Mfr/Model: TBD PM/ PM_{10} Control: 99%	Stack Parameters: SRC11 and SRC12 Stack Height: 10.0 m Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient

Emissions Limits

3.3 Emission Limits (BACT for Particulate Matter)

Particulate matter and PM_{10} emissions from any baghouse stack, or any other stack, vent, or functionally equivalent opening associated with coal and petcoke railcar unloading, conveying, storage, or processing (e.g., grinding, milling, and screening) shall not exceed the pound per hour limits listed in Table 3.3. These emission limits shall apply at all times.

Table 3.3 EMISSION LIMITS FOR FEEDSTOCK HANDLING POINT SOURCES

Source ID No.	Description	Pollutant-Specific BACT Emission Limits
(TBD)	Fluxant Silo Filling	
	Coal/Petcoke	Each Source:
SRC01	Railcar Unloading	
SRC02	Railcar Hopper to Railcar Conveyor	PM: 0.09 lb/hr
SRC03	Railcar Conveyor to Silo Conveyors	PM_{10}: 0.04 lb/hr
SRC04	Silo Conveyor to Stacker Conveyors	
SRC05	Silo 3 Vent	
SRC06	Silo 1 Vent	
SRC07	Silo 2 Vent	
	Coal/Petcoke	Each Source:
SRC08	Silo 1 Reclaimer to Reclaim Conveyor	
SRC09	Silo 2 Reclaimer to Reclaim Conveyor	PM: 0.002 lb/hr
SRC10	Silo 3 Reclaimer to Reclaim Conveyor	PM_{10}: 0.001 lb/hr
SRC11	Reclaim Conveyor to Rod Mill Hopper 1	
SRC12	Reclaim Conveyor to Rod Mill Hopper 2	

3.4 Opacity Limit (BACT for Particulate Matter)

Particulate matter emissions from any baghouse stack, or any other stack, vent, or functionally equivalent opening associated with coal and petcoke railcar unloading, conveying, storage, or processing (e.g., grinding, milling, and screening) shall not exceed **5 percent opacity**. Method 9 of Appendix A to 40 CFR 60 and the procedures in §60.11 shall be used to determine opacity. This opacity standard shall apply at all times except during periods of startup, shutdown, or malfunction.

3.5 Opacity Limit (NSPS, 40 CFR 60, Subpart Y)

In accordance with 40 CFR 60.251(c), on and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit **20 percent opacity** or greater. Method 9 of Appendix A to 40 CFR 60 and the procedures in §60.11 shall be used to determine opacity. In accordance with 40 CFR 60.11(c), the opacity standard shall apply at all times except during periods of startup, shutdown, or malfunction.

Operating Requirements

3.6 Emission Controls – BACT for Particulate Matter

The permittee shall:

- Construct and maintain enclosures as described in Table 3.1 to control PM and PM_{10} emissions from coal, petcoke, and fluxant unloading, conveying, storage, and processing (i.e., grinding, milling, and screening);
- Install, operate, and maintain baghouses with a minimum 99% capture efficiency to control PM and PM_{10} emissions from coal and petcoke unloading, conveying, storage, and processing (i.e., grinding, milling, and screening), and to control particulate emissions from fluxant silo filling. The baghouses shall be operated at all times when material is being transferred or processed.
- Install and maintain water sprays or equivalent to provide a minimum 75% control for fugitive particulate emissions from fluxant unloading, conveying, and storage. If used, water sprays shall be

operated in accordance with the O&M manual, and alternative equivalent controls shall be used during freezing conditions.

Monitoring and Recordkeeping Requirements

3.7 Feedstock Analysis

3.7.1 Prior to the initial startup that includes feeding slurry containing coal, petcoke, or fluxant to either gasifier, the permittee shall characterize the feedstocks by obtaining analysis results for representative composite samples from the feedstock supplier or shall sample and analyze the feedstocks to determine the concentration of the following toxics:

- Metals in Coal/Petcoke/Fluxant: Arsenic, Cadmium, Chromium (total and hexavalent), Cobalt, Lead, Manganese, Mercury, and Nickel.

3.7.2 Sampling and analysis shall be conducted in accordance with EPA Reference Methods or other method approved by DEQ.

3.7.3 The permittee shall obtain analysis results for the toxics listed in Permit Condition 3.7.1 for representative samples of feedstock prior to acceptance of coal, petcoke, or fluxant from a new mine or supplier.

3.7.4 The permittee shall obtain analysis results for the toxics listed in Permit Condition 3.7.1 for representative samples of feedstock at least every two years.

3.7.5 Records detailing the sampling method; sample identification; sampling date, time, and location; laboratory results; and any laboratory QA analysis shall be maintained in accordance with General Provision 7.

3.8 Initial Performance Tests for Particulate Matter

3.8.1 **NSPS, 40 CFR 60, Subpart Y**. In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the affected facility (i.e., coal transfer and loading systems, coal storage systems, and coal processing and conveying equipment) will be operated, but not later than 180 days after initial startup of such facility, the owner or operator of such facility shall conduct performance test(s) to demonstrate compliance with the 20% opacity limit specified in Permit Condition 3.5. Tests shall be conducted for all baghouse stacks, vents, or equivalent openings associated with any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal at the PCAEC.

Opacity shall be determined using Method 9 of Appendix A to 40 CFR 60 and the procedures in 40 CFR 60.11. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages).

3.8.2 **BACT Compliance**. Not later than 180 days after initial startup of the coal and petcoke handling facility, the permittee shall conduct performance test(s) to demonstrate compliance with the PM, PM10, and 5% opacity limits specified in Permit Conditions 3.3 and 3.4. Tests shall be conducted for all baghouse stacks, vents, or equivalent openings associated with coal and petcoke handling at the PCAEC.

Opacity shall be determined using Method 9 of Appendix A to 40 CFR 60. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages).

The permittee is encouraged to submit a source testing protocol to DEQ for approval 30 days prior to conducting the performance test. The source test shall be conducted under "worst case normal" conditions as required by IDAPA 58.01.01.157 and General Provision 6, and the source test report shall contain documentation that the test was conducted under these conditions. General Provision 6 includes notification requirements, testing procedures and reporting requirements.

The permittee shall monitor and record the following during each performance test:

- The material handling operation (e.g., unloading, conveying, silo-filling, grinding/milling),
- Type of material (petcoke or coal and coal rank),
- Moisture content of the feedstock on an as-received basis, and
- Material throughput in tons per hour for the material handling operations associated with the stack being tested.

3.9 Periodic Performance Tests for Particulate Matter

3.9.1 The permittee shall conduct performance tests at a frequency of no less than once every five years to demonstrate compliance with the PM, PM_{10}, and 5% opacity limits specified in Permit Conditions 3.3 and 3.4.

3.9.2 The permittee is encouraged to submit a source testing protocol to DEQ for approval 30 days prior to conducting the performance test. **With prior DEQ approval, periodic testing may be conducted on representative baghouses in lieu of testing all baghouses associated with coal/petcoke handling**. The source test shall be conducted under "worst case normal" conditions as required by IDAPA 58.01.01.157 and General Provision 6, and the source test report shall contain documentation that the test was conducted under these conditions. General Provision 6 includes notification requirements, testing procedures and reporting requirements.

3.9.3 The permittee shall monitor and record the following during each performance test:

- The material handling operation (e.g., unloading, conveying, silo-filling, grinding/milling),
- Type of material (petcoke or coal and coal rank),
- Moisture content of the feedstock on an as-received basis, and
- Material throughput in tons per hour for the material handling operations associated with the stack being tested.

Reporting Requirements

3.10 Construction and Initial Startup Notification (NSPS, 40 CFR 60, Subpart A, General Provisions)

For the affected facility subject to NSPS, 40 CFR 60 Subpart Y, which includes coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal at the PCAEC, the permittee shall submit notification of the date that construction commences (postmarked no later than 30 days after such date), and the date of initial startup (postmarked no later than 15 days after such date), in accordance with 40 CFR 60.7(a)(1) and 60.7(a)(3).

4. NATURAL GAS-FIRED HEATERS

4.1 Process Description

Permit Conditions 4.1 and 4.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

The Air Separation Unit (ASU) regen heater will be used to regenerate the molecular sieves in the ASU. The gasifier heaters will be used to preheat the gasifiers at startup. Once the gasifiers have been preheated, the heater for the gasifier being operated in production mode will be shut down, and the heater for the gasifier being operated in standby mode will continue to be operated at a level necessary to maintain the standby gasifier at the appropriate temperature.

4.2 Emissions Control Description

Table 4.1 NATURAL GAS-FIRED HEATERS DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
ASU Regen Heater Manufacturer: TBD Model: TBD Max Heat Input: 100,000 Btu/hr Fuel: Natural Gas Operations: 8,760 hr/yr	None	Stack Parameters, SRC13: Stack Height: 4.0 m (13.1 ft) Exit Diameter: 0.05 m (0.16 ft) Orientation: vertical Exit flow rate: 37 acfm Exit Velocity: 9.0 m/sec Exit Temperature: 355 K (179.3^{o}F)
Gasifier Heater #1 and Gasifier Heater #2: Manufacturer: TBD Model: TBD Startup: 25.5 MMBtu/hr avg (each) Standby: 9 MMBtu/hr avg (each) Fuel: Natural Gas Operations: 8,760 hr/yr (each)	None	Gasifier Heater Vent #1 and Vent #2 Stack Parameters, SRC14, SRC15: Stack Height: 51.8 m (170 ft) Exit Diameter: 0.5 m (1.64 ft) Orientation: vertical Exit flow rate: 5,309 acfm Exit Velocity: 15.3 m/sec Exit Temperature: 811 K (1000.1^{o}F)

Operating Requirements

4.3 Heater Fuels and Operating Practices

4.3.1 The ASU regen heater and the gasifier heaters shall be operated using:

- Natural gas, exclusively; and
- Good combustion practices at all times.

4.3.2 The use of natural gas exclusively and good combustion operating practices are considered BACT for these relatively small heaters.

5. DIESEL-FIRED EMERGENCY ENGINE GENERATORS

5.1 Process Description

Permit Conditions 5.1 and 5.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC. A nominal 2,000 kW (2 MW) emergency engine generator will supply backup power to the facility when the utility power supply is interrupted. A nominal 500 kW emergency engine generator or a National Fire Protection Association (NFPA) 20-certified fire pump engine will supply power for pumping water to the facility's fire suppression systems.

5.2 Emissions Control Description

Table 5.1 DIESEL-FIRED EMERGENCY ENGINE GENERATOR DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
2,000 kW (2 MW) Emergency Engine Generator Manufacturer: Caterpillar Model: TBD Max Rating: Nominal 2 MW output Displacement: < 10 liters per cylinder Emissions: Minimum EPA Tier 2 Fuel: Distillate fuel oil (Diesel) Operations: Maximum 100 hr/yr	None	Emergency Generator Stack Parameters, SRC25: Stack Height: 10.1 m (33.0 ft) Exit Diameter: 0.6 m (2.0 ft) Orientation: vertical Exit flow rate: 15,136 acfm Exit Velocity: 24.5 m/sec Exit Temperature: 679 K (762.5^{o}F)
500 kW Emergency Engine Generator (Fire Pump) Manufacturer: TBD Model: Nominal 500 kW output Displacement: < 10 liters per cylinder Emissions: EPA Tier 3 (for a gen set not meeting NFPA 20) 40 CFR 60, Subpart IIII (NFPA 20 fire pump) Fuel: Distillate fuel oil (Diesel) Operations: Maximum 100 hr/yr	None	Firewater Pump Engine Generator Stack Parameters, SRC26: Stack Height: 4.6 m (15.0 ft) Exit Diameter: 0.3 m (1.0 ft) Orientation: vertical Exit flow rate: 3,842 acfm Exit Velocity: 24.9 m/sec Exit Temperature: 779 K (942.5^{o}F)

Emissions Limits

5.3 Emission Limits (NSPS, 40 CFR 60, Subpart IIII)

The emissions from the diesel-fired emergency engine generators shall not exceed the limits shown in Table 5.2, in accordance with 40 CFR 60.4205(b). The use of diesel engines certified to meet the Subpart IIII emission standard for the applicable model and year is considered BACT for these sources.

Table 5.2 EMERGENCY ENGINE GENERATOR EXHAUST EMISSIONS LIMITS (40 CFR 60, SUBPART IIII)

Emission Unit	Regulation	NMHC + NO_x[a] (g/kW-hr)	CO (g/kW-hr)	PM (g/kW-hr)
Emergency Engine Generator, Nominal 2,000 kW	40 CFR 89.112, Table 1, kW > 560: Tier 2	6.4	3.5	0.20
Emergency Generator Set, Nominal 500 kW				
NFPA 20-certified fire pump engine, Ordered in 2008 or earlier.	40 CFR 60, Subpart IIII, Table 4 130 < kW < 560:	10.5	3.5	0.54
NFPA 20-certified fire pump engine, Ordered in 2009 or later.		4.0	---	0.20
Emergency Engine Generator, 500 kW	40 CFR 89.112, Table 1 450 ≤ kW ≤ 560: Tier 3	4.0	3.5	0.20

[a] NMHC = Nonmethane hydrocarbons

5.4 Opacity Limit (NSPS, 40 CFR 60, Subpart IIII)

In accordance with 40 CFR 60.4205(b) and 40 CFR 89.113, exhaust opacity from emergency engine generator(s) that are not NFPA 20-certified fire pump engines shall not exceed 20 percent during the acceleration mode, 15 percent during the lugging mode, and 50 percent during the peaks in either the acceleration or lugging modes. Opacity levels shall be measured and calculated as set forth in 40 CFR part 86, subpart I.

5.5 Opacity Limit (IDAPA 58.01.01.625)

The exhaust from the emergency engine generator(s) and fire pump engine generator shall not exceed the 20% opacity limit specified in Permit Condition 2.6.

Operating Requirements

5.6 Allowable Fuels (NSPS, 40 CFR 60, Subpart IIII)

The emergency generators shall combust only diesel fuel meeting the requirements of Permit Condition 2.13, in accordance with 40 CFR 60.4207(a) and (b).

5.7 Maximum Hours of Operation

The operation of each emergency generator shall not exceed a maximum of 100 hours in any consecutive 12-calendar month period for maintenance checks. Any operation other than maintenance and testing (subject to the 100 hour per year maximum) and emergency operation, is prohibited in accordance with 40 CFR 60.4211(e)..

5.8 Engine Generator Operation and Maintenance (NSPS, 40 CFR 60, Subpart IIII)

5.8.1 The permittee shall operate and maintain the emergency generators according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer, over the entire life of the engine, in accordance with 40 CFR 60.4206 and 4211(a).

5.8.2 The permittee may only change those settings that are permitted by the manufacturer, in accordance with 40 CFR 60.4211(a).

5.9 Other Requirements for Owners and Operators (NSPS, 40 CFR 60, Subpart IIII)

The permittee shall comply with the deadlines specified in 40 CFR 60.4208(a) through (g).for installing and importing stationary compression-ignition internal combustion engines (i.e., diesel engines), except for stationary diesel engines that have been modified or reconstructed or that were removed from one existing location and reinstalled at a new location as specified in 40 CFR 60.4208(h).

5.10 Engine Generator Replacement (NSPS, 40 CFR 60, Subpart IIII)

The owner or operator of a 2007 model year and later stationary CI ICE that must comply with the emission standards specified in 60.4205(b), and the owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to the fire pump engine rating in Table 3 to Subpart IIII that must comply with the emission standards specified in 60.4205(c), must comply by purchasing an engine certified to the emission standards of 40 CFR 60.4205(b) for the same model year and maximum engine power (or in the case of fire pumps, NFPA nameplate engine power), in accordance with 40 CFR 60.4211(c).

Monitoring and Recordkeeping Requirements

5.11 Fuel Monitoring and Recordkeeping

The permittee shall monitor and record fuel oil sulfur content and cetane index or maximum aromatic content in accordance with Permit Condition 2.15.

5.12 Compliance Monitoring (NSPS, 40 CFR 60, Subpart IIII)

The permittee shall install a non-resettable hour meter on each diesel engine prior to startup of the diesel engines, in accordance with 40 CFR 60.4209(a).

5.13 Operating Hours Monitoring

The permittee shall monitor and record the operating hours and reason(s) for operation of each emergency engine generator and/or fire pump engine on a monthly basis, summing the monthly totals for the previous consecutive 12-calendar month period, to demonstrate compliance with the annual hour limit specified in Permit Condition 5.7. Records of this information shall be maintained in accordance with General Provision 7.

Testing Requirements

5.14 Testing Requirements for Owners and Operators (NSPS, 40 CFR 60, Subpart IIII)

Any performance tests on the diesel engines shall be conducted according to the paragraphs of 40 CFR 60.4212(a) through (d).

Reporting Requirements

5.15 Notification, Reports, and Records for Owners and Operators (NSPS, 40 CFR 60, Subpart IIII)

5.15.1 In accordance with 40 CFR 60.4214(b), the initial notification described in 40 CFR 60.7(a)(1) **is not required** for emergency engine generators.

5.15.2 In accordance with 40 CFR 60.7(a)(3), the permittee shall submit notification of the date of initial startup of each emergency engine generator (postmarked no later than 15 days after such date).

6. PACKAGE BOILER AND STEAM SUPERHEATER BOILER

6.1 Process Description

Permit Conditions 6.1 and 6.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

Various processes throughout the plant will produce and consume steam at different pressure levels through chemical reactions, process equipment, and heating/cooling needs.

For Operating Scenario #1, in which a Claus sulfur recovery unit would be used to control sulfur compound emissions, a natural gas-fired package boiler will be used to produce steam during startup and shutdown. A similarly-sized steam superheater boiler will be used to produce and/or superheat steam during normal operations. The steam superheater boiler will be operated on natural gas or a mix of natural gas and project fuel gas (i.e., tailgas from the pressure swing adsorber (PSA)). The steam superheater boiler will be installed in the package boiler structure. The stacks for these two boilers will be co-located. During the transition between startup and normal operations, and from normal operations to shutdown, the boiler operations will be balanced, i.e., as steam production in one boiler increases the steam production in the other boiler will be decreased to maintain a steady steam production rate.

For Operating Scenario #2, in which a wet sulfuric acid plant would be used to control sulfur compound emissions from acid gas removal, a package boiler fired on natural gas or a mix of natural gas and PSA tailgas will be used to produce steam at the needed pressure levels. A steam superheater boiler will not be included as part of the project in Scenario #2.

6.2 Emissions Control Description

Table 6.1 PACKAGE BOILER AND STEAM SUPERHEATER BOILER DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Package Boiler Manufacturer/Model: TBD Max Rating: 250 MMBtu/hr heat input Heat Release Rate: (High or Low, TBD) Operating Scenario #1: 8,760 hr/yr at full rating (combined with Steam Superheater hours) Fuel: Natural Gas (max 250 MMBtu/hr) Heat Content: ~1,020 Btu/scf Sulfur Content: 2.0 gr/100 dscf PSA Tailgas (max 250 MMBtu/hr) Heat Content: ~250 Btu/scf Sulfur Content: 25 ppmv Operating Scenario #2: 8,760 hr/yr at full rating (Package Boiler hours only) Fuel: Natural Gas Only Sulfur Content: 2.0 gr/100 dscf	Low-NO_x burner and Operating Scenario #1 Flue Gas Recirculation (FGR) Purpose: NO_X reduction Efficiency: 95% control for NO_X Operating Scenario #2 Flue Gas Recirculation (FGR) Purpose: NO_X reduction Efficiency: 95% control for NO_X	Package Boiler Stack Parameters, SRC24: Stack Height: 33.5 m (110 ft) Exit Diameter: 1.8 m (5.9 ft) Orientation: vertical Exit flow rate: 52,282 acfm Exit Velocity: 10.3 m/sec Exit Temperature: 422 K (299.9^oF)

Table 6.1 PACKAGE BOILER AND STEAM SUPERHEATER BOILER DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Steam Superheater Boiler Manufacturer/Model: TBD Max Rating: 250 MMBtu/hr heat input Heat Release Rate: (High or Low, TBD) Operating Scenario #1: 8,760 hr/yr at full rating (combined with Package Boiler hours) Fuel: Natural Gas (max 250 MMBtu/hr) Heat Content: 1,020 Btu/scf Sulfur Content: 2.0 gr/100 dscf PSA Tailgas (max 250 MMBtu/hr) Heat Content: ~250 Btu/scf Sulfur Content: 25 ppmv Operating Scenario #2: Superheater not installed	Low-NO_X burner and Operating Scenario #1: Selective Catalytic Reduction (SCR) Manufacturer/Model: TBD Purpose: NO_x reduction Efficiency: 97% control for NO_X Ammonia slip: $\leq$ 10 ppmv (dry), corrected to 15% O_2 Operating Scenario #2: Not applicable	Steam Superheater Stack Parameters, SRC31: Stack Height: 33.50 m (109.9 ft) Exit Diameter: 1.8 m (5.9 ft) Orientation: vertical Exit flow rate: 52,282 acfm Exit Velocity: 10.3 m/sec Exit Temperature: 422 K (299.9^oF)

Emissions Limits

6.3 Emissions Limits (BACT)

6.3.1 The pound per hour emission limits listed in Table 6.2 are BACT for these sources, based on using low-NO_x burners for both the package boiler and steam superheater boiler, FGR to control NO_x emissions from the package boiler, and SCR with a maximum ammonia slip of 10 ppmv (dry) to control NO_x emissions from the steam superheater boiler.

6.3.2 The emissions from the package boiler and steam superheater boiler (affected facility) shall not exceed any corresponding emissions rate limits listed in Table 6.2.

Table 6.2 PACKAGE BOILER AND STEAM SUPERHEATER BOILER EMISSIONS LIMITS (BACT)[1]

Source Description	PM		PM_{10}[2]		SO_2		NO_X		VOC		CO	
	lb/hr[3]	T/yr[4]	lb/hr[3]	T/yr[4]	lb/hr	T/yr[4]	lb/hr[3]	T/yr[4]	lb/hr	T/yr[4]	lb/hr	T/yr[4]
Operating Scenario #1 250 MMBtu/hr Package Boiler and 250 MMBtu/hr Steam Superheater, combined	1.3	5.7	1.3	5.7	1.4	6.3	5.0	21.9	1.0	4.4	18.5	81.0
Operating Scenario #2 250 MMBtu/hr Package Boiler	1.3	5.7	1.3	5.7	1.4	6.3	5.0	21.9	1.0	4.4	18.5	81.0

1) In the absence of any other creditable evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements. **Lb/hr limits are BACT.**
2) Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.
3) As determined by source test methods prescribed by IDAPA 58.01.01.157.
4) Tons per any consecutive 12-calendar month period.

6.4 Standard for Particulate Matter (NSPS, 40 CFR 60, Subpart Db)

6.4.1 The provisions in this permit condition apply only when burning only PSA tailgas or a mixture of PSA tailgas and natural gas in the boiler(s).

6.4.2 Emissions. On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the permittee shall not cause to be discharged into

the atmosphere from the boiler stack any gases that contain PM in excess of the following, in accordance with 40 CFR 60.43b(h)(1) and (h)(2):

- 13 ng/J (0.030 lb/MMBtu) heat input, or
- 22 ng/J (0.051 lb/MMBtu) heat input and 0.2 percent of the combustion concentration (99.8 percent reduction).

6.4.3 Opacity. On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the permittee shall not cause to be discharged into the atmosphere from the boiler stack any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity, in accordance with 40 CFR 60.43b(f).

6.4.4 The PM and the opacity standards under 60.43b apply at all times, except during periods of startup, shutdown, and malfunction, in accordance with 40 CFR 60.43b(g) and 60.46b(a).

6.5 Opacity Limit (IDAPA 58.01.01.625)

The emissions from the package boiler and steam superheater boiler stacks shall not exceed the 20% opacity limit specified in Permit Condition 2.6.

6.6 Particulate Matter Limit (IDAPA 58.01.01.676)

Emissions of particulate matter from the package boiler and steam superheater boiler stacks shall not exceed the limits specified in Permit Condition 2.11, i.e., shall not exceed 0.015 gr/dscf of effluent gas corrected to 3% oxygen when burning only natural gas, PSA tailgas, or a mixture of natural gas and PSA tailgas.

6.7 Standard for Nitrogen Oxides (NSPS, 40 CFR 60, Subpart Db)

6.7.1 On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the NO_x emissions from the package boiler and steam superheater boiler stacks shall not exceed any corresponding emissions rate limits listed in Table 6.3.

Table 6.3 NOx EMISSION RATE LIMITS (NSPS)

Boiler Fuel	Applicable Regulation	NO_x Emission Limit (expressed as NO_2)
When burning only natural gas	60.44b(a)(1)(i) Low heat release rate	43 ng/J (0.10 lb/MMBtu)
When burning only natural gas	60.44(a)(1)(ii) High heat release rate	86 ng/J (0.20 lb/MMBtu)
When burning only PSA tail gas	60.44b(a)(3)(vi) Coal-derived synthetic fuels	210 ng/J (0.50 lb/MMBtu)

Table 6.3 NOx EMISSION RATE LIMITS (NSPS)

Boiler Fuel	Applicable Regulation	NO_x Emission Limit (expressed as NO_2)
When burning a mix of natural gas and PSA tail gas	60.44b(b) Heat release rate not specified	$$E_n = \frac{(EL_g x H_g) + (EL_c x H_c)}{(H_g + H_c)}$$ Where: E_n = NO_x emission limit in ng/J or lb/MMBtu, EL_g = Natural gas emission limit: EL_c = Coal (PSA tailgas) emission limit H_g = 30-day* heat input from combustion of natural gas, and H_c = 30-day* heat input from combustion of coal (PSA tailgas). *Per 44b(i), emission limits in this subpart are determined on a rolling 30-day average
When burning a mix of natural gas and PSA tail gas, and natural gas comprises > 30% of the 30-day heat input.	60.44b(l)(2) Low heat release rate	$$E_n = \frac{(0.10 x H_g) + (0.20 x H_r)}{(H_g + H_r)}$$ Where: E_n = NO_x emission limit in ng/J or lb/MMBtu, H_g = 30-day heat input from combustion of natural gas, and H_r = 30-day heat input from combustion of any other fuel (PSA tailgas only).

6.7.2 The NO_x emission limits under 60.44b apply at all times, including periods of startup, shutdown, or malfunction, in accordance with 40 CFR 60.44b(h).

Operating Requirements

6.8 Package Boiler and Steam Superheater Boiler Fuels

The Package Boiler and Steam Superheater Boiler shall combust only natural gas, PSA tailgas, or a mixture of natural gas and PSA tailgas.

6.9 Standard for Sulfur Dioxide – Fuel SO_2 Emission Rate (NSPS, 40 CFR 60, Subpart Db)

6.9.1 In accordance with 40 CFR 60.42b(k)(2), the permittee shall not combust any fuel with a potential SO_2 emission rate in excess of 140 ng/J (0.32 lb/MMBtu) in the package boiler or steam superheater boiler.

6.9.2 The SO_2 emission limits under 60.42b apply at all times, including periods of startup, shutdown, or malfunction, in accordance with 40 CFR 60.44b(g) and 60.45b(a).

6.9.3 In accordance with 40 CFR 60.48b(j)(2), the permittee either shall not combust any fuel with a potential SO_2 emission rate in excess of 26 ng/J (0.060 lb/MMBtu) in the package boiler or steam superheater boiler, or shall install a COMS to monitor opacity when combusting PSA tailgas or a mixture of PSA tailgas and natural gas.

6.10 Pollution Control Equipment for NOx

6.10.1 Operating Scenario #1.

- The package boiler and the steam superheater boiler shall each use low-NOx burners, exclusively.

- The permittee shall install, maintain, and operate a flue gas recirculation (FGR) system that achieves the NO_x emission limits specified in this permit for the package boiler stack.
- The FGR system shall be operated at all times when the package boiler is operating.
- The permittee shall install, maintain, and operate a selective catalytic reduction (SCR) system that achieves the NO_x emission limits specified in this permit for the steam superheater boiler stack.
- SCR Ammonia Slip shall not exceed 10 ppmv (dry), converted to 15% oxygen.
- The SCR system shall be operated at all times when the steam superheater boiler is operating.

6.10.2 Operating Scenario #2.

- The package boiler shall use a low-NOx burner, exclusively.
- The permittee shall install, maintain, and operate a flue gas recirculation (FGR) system that achieves the NO_x emission limits specified in this permit for the package boiler stack.
- The FGR system shall be operated at all times when the package boiler is operating.

Monitoring and Recordkeeping Requirements

6.11 Reporting Period (NSPS, 40 CFR 60, Subpart Db)

6.11.1 In accordance with 40 CFR 60.49b(v), with prior EPA and DEQ approval, the permittee may submit electronic copies of required reports on a quarterly basis.

6.11.2 In accordance with 40 CFR 60.49b(w), the reporting period for reports required under 40 CFR 60, Subpart Db is each 6 month period. Reports shall be postmarked by the 30th day following the end of the reporting period.

6.12 Fuel Combustion Monitoring and Recordkeeping (NSPS, 40 CFR 60, Subpart Db)

6.12.1 In accordance with 40 CFR 60.49b(d), the permittee shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal (PSA tailgas) and natural gas for the reporting period. The annual capacity factor is determined on a 12-calendar month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

6.12.2 In accordance with 40 CFR 60.41b (Definitions), the annual capacity factor means the ratio between the actual heat input to a steam generating unit from the natural gas and PSA tailgas, as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity.

6.12.3 The permittee shall calculate the 30-day heat input based on the amounts of each fuel combusted each day, and shall determine which NO_x emission limit specified in Table 6.3 that applies to the 30-day period.

6.13 Emissions Monitoring for PM – Opacity (NSPS, 40 CFR 60, Subpart Db)

If fuel with a potential SO_2 emission rate in excess of 26 ng/J (0.060 lb/MMBtu) will be combusted in the package boiler or steam superheater boiler, the permittee shall install, calibrate, maintain, and operate a CEMS for measuring opacity of emissions (i.e., a COMS) discharged from the boiler stack

whenever PSA tailgas or a mix of PSA tailgas and natural gas is combusted in the boiler. The output of the system shall be recorded.

6.14 Emissions Monitoring for NOx – CEMS or PEMS (NSPS, 40 CFR 60, Subpart Db)

6.14.1 The permittee shall maintain NO_x emission records for each steam generating unit operating day in accordance with 60.49b(g).

6.14.2 Compliance with the NO_x emission limits under 60.44b shall be determined on a 30-day rolling average basis, in accordance with 40 CFR 60.44b(i).

6.14.3 In accordance with 40 CFR 60.48b(g)(1) or (g)(2), the permittee shall comply with (1) or (2) below:

(1) NO_x CEMS. In accordance with 40 CFR 60.48b(b)(1), install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_x and O_2 (or CO_2) emissions discharged to the atmosphere from the package boiler stack and steam superheater boiler stack, and shall record the output of the system.

a. In accordance with 40 CFR 60.48b(c), the NO_x CEMS shall be operated and data recorded during all periods of operation of the package boiler and steam superheater boiler except for continuous monitoring system breakdown and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

b. In accordance with 40 CFR 60.48b(d), the 1-hour average NOx emission rates measured by the continuous NO_x monitor required by paragraph (b) of this section and required under 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under 60.44b. The 1-hour averages shall be calculated using the data points required under 60.13(h)(2).

c. In accordance with 40 CFR 60.48b(e), the procedures under 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

d. In accordance with 40 CFR 60.48b(e)(2), when combusting coal (PSA tailgas) or natural gas, the span value for NO_x shall be determined using the procedures listed in 60.48b(e)(2).

e. In accordance with 40 CFR 60.48b(e)(3), all span values computed under paragraph 60.48b(e)(2)(i) for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph 60.48b(e)(2)(ii) shall be rounded off according to Section 2.1.2 in Appendix A to 40 CFR 75.

f. In accordance with 40 CFR 60.48b(f), when NO_x emission data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 or Method 7A of Appendix A to 40 CFR 60, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(2) NO_x Predictive Emissions Monitoring System (PEMS). In accordance with 40 CFR 60.48b(g)(2), monitor steam generating unit operating conditions and predict NO_x emission rates as specified in a plan submitted to DEQ for approval pursuant to 60.49b(c). The permittee shall submit the plan to DEQ for approval within 360 days of the initial startup of the boiler for which the PEMS will apply. In accordance with 60.49b(c), the plan shall identify the operating conditions to be monitored under 60.48b(g)(2) and the records to be maintained under 60.49b(j). If the plan is approved, the permittee

shall maintain records of predicted NOx emission rates and the monitored operating conditions, including steam generating unit heat input in MMBtu/hr, identified in the plan. The plan shall:

a. Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_x emission rates (i.e., ng/J or lb/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas O_2 level).

b. Include the data and information that the owner or operator used to identify the relationship between NO_x emission rates and these operating conditions; and

c. Identify how these operating conditions, including steam generating unit heat input in MMBtu/hr, will be monitored under 60.48b(g) on an hourly basis by the permittee during the period of operation of the package boiler and steam superheater boiler, the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit heat input, that will be maintained by the permittee under 60.49b(j).

6.15 Fuel Potential SO_2 Emission Rate Monitoring (NSPS, 40 CFR 60, Subpart Db)

6.15.1 In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the package boiler or steam superheater boiler will be operated, but not later than 180 days after the initial startup of the boiler(s), the permittee shall demonstrate compliance with the applicable potential fuel SO_2 emission rate limit specified in Permit Condition 6.9.

6.15.2 In accordance with 40 CFR 60.45b(k) and 60.49b(r), the permittee shall develop and submit a site-specific fuel analysis plan to DEQ for review and approval no later than 60 days before the date you intend to demonstrate compliance with the applicable potential fuel SO_2 emission rate limit specified in Permit Condition 6.9. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J and lb/MMBtu heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition DEQ to approve monthly or quarterly sampling in place of weekly sampling.

6.16 Particulate Matter and NOx, Initial Performance Test (NSPS, 40 CFR 60, Subpart Db)

6.16.1 In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the package boiler or steam superheater boiler will be operated, but not later than 180 days after the initial startup of the boiler(s), the permittee shall conduct performance test(s) to demonstrate compliance with the:

- PM and opacity limits listed in Permit Condition 6.4, and
- Applicable NO_x emission limits listed in Permit Condition 6.7.

6.16.2 In accordance with 40 CFR 60.46b(d), PM performance testing shall be conducted while burning the maximum amount of PSA tailgas expected to be mixed with natural gas during normal operations, and shall be conducted in accordance with the procedures and reference methods in 60.46b(d). If a PM CEMS is used in lieu of conducting Methods 5, 5B, or 17 of Appendix A to 40 CFR 60, compliance shall be determined in accordance with 60.46b(j)(1) through (j)(13).

6.16.3 In accordance with 40 CFR 60.46b(c), NO_x performance testing shall be conducted for both the package boiler and the steam superheater boiler in accordance with:

- 60.46b(e) The initial performance test required under §60.8 shall be conducted using the continuous monitoring system (i.e., a NO_x CEMS or DEQ-approved NO_x PEMS),
- (e)(1) For the initial compliance test, NO_x from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission standards under 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.
- (e)(2) when combusting PSA tailgas or a mix of PSA tailgas and natural gas, and
- (e)(4) when combusting only natural gas.

6.16.4 After the initial performance test, periodic testing for PM and NOx to demonstrate compliance with the emission limits listed in Permit Condition 6.16.1 shall be conducted at least once every five (5) years, or as requested by DEQ. The permittee is encouraged to submit a source testing protocol for approval 30 days prior to conducting the performance test. Notifications, testing procedures and reporting shall be done in accordance with General Provision 6.

6.17 Performance Testing (BACT)

6.17.1 Within 180 days after the initial startup of the package boiler and the steam superheater boiler, the permittee shall conduct a performance test on the package boiler and the steam superheater boiler stacks to demonstrate compliance with:

- The pound per hour PM, PM_{10} (including condensables), and NO_x emission limits listed in Permit Condition 6.3,
- The 20% opacity limit listed in Permit Conditions 6.5 and 2.6, and
- The PM limit of 0.015 gr/dscf of effluent gas corrected to 3% oxygen listed in Permit Condition 6.6.

6.17.2 The averaging period shall be as determined by source test methods prescribed by IDAPA 58.01.01.157.

6.17.3 The permittee shall test in accordance with IDAPA 58.01.01.157 and the conditions of this permit including the operating requirements for the package boiler and steam superheater boiler, and General Provision 6. The source test shall be conducted under "worst case normal" conditions as required by IDAPA 58.01.01.157 and General Provision 6. For any boiler intended to operate on a mix of natural gas and PSA tailgas, the performance test shall be conducted while burning the maximum amount of PSA tailgas expected to be combined with natural gas during normal operations. The source test report shall contain documentation that the test was conducted under these conditions.

The permittee is encouraged to submit a source testing protocol for approval 30 days prior to conducting the performance test. General Provision 6 includes notification requirements, testing procedures and reporting requirements.

The permittee shall monitor and record the following during the performance test:

- The potential SO_2 emission rate in lb/MMBtu of the natural gas and of the PSA tailgas,
- The heat input in MMBtu/scf of the natural gas and of the PSA tailgas,
- The flow rate in MMscf per hour of natural gas and of PSA tailgas,
- For any SCR unit, the amount of ammonia slip in ppmv (dry), converted to 15% oxygen.
- For a boiler FGR system, the flue gas recirculation rate, by temperature measurement or by oxygen measurement.

6.17.4 After the initial performance test, periodic testing to demonstrate compliance with the emission limits listed in Permit Condition 6.17.1 shall be performed at least once every five (5) years, or as requested by DEQ.

Reporting Requirements

6.18 Initial Startup Report (NSPS, 40 CFR 60, Subpart Db)

6.18.1 In accordance with 60.49b(a), the permittee shall submit notification of the date of initial startup, as provided by 40 CFR 60.7. This notification shall include the information described in 40 CFR 60.49b(a).

6.18.2 In conjunction with the initial startup notification, the permittee shall include the calculated heat release rate in Btu/hr-ft^3 when operating on only natural gas, and when operating on a mix of natural gas and PSA tailgas for the boiler being started up. The heat release rate for mixes of natural gas and PSA tailgas shall be provided for a range of mixtures, including but not limited to, mixtures containing natural gas and 10%, 30%, 50%, 70%, and 90% PSA tailgas by volume.

6.19 Initial Performance Test and CEMS Evaluation Reports (NSPS, 40 CFR 60, Subpart Db)

In accordance with 60.49b(b), the permittee shall submit the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in 40 CFR 60, Appendix B.

6.20 NOx Emissions (CEMS/PEMS) Reporting

In accordance with 60.49b(i), the permittee shall submit reports containing the NO_x emission records for each steam generating unit operating day. The reports shall include the information listed in 60.49b(g).

6.21 Excess Emissions (NSPS, 40 CFR 60, Subpart Db)

6.21.1 In accordance with 60.49b(h)(1) and (h)(2), the permittee shall submit excess emission reports for any excess emissions of opacity (when burning PSA tailgas or a mixture of PSA tailgas and natural gas), and NO_x (when burning any permitted gaseous fuel) that occurred during the reporting period.

6.21.2 In accordance with 60.49b(h)(3), excess emissions of opacity are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under 60.43b(f).

6.21.3 In accordance with 60.49b(h)(4), excess NO_x emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under 60.46b(e), that exceeds the applicable emission limits listed in Table 6.3 of this permit.

7. GASIFICATION ISLAND

7.1 Process Description

Permit Conditions 7.1 and 7.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

Two GE Quench gasifiers will be installed. A single gasifier will operate at a time, while the other gasifier will be held in hot standby using a natural gas-fired heater (see Section 4.0, Natural Gas-Fired Heaters). Oxygen from the air separation unit (ASU) and a slurry of coal/petcoke, fluxant, and water are fed to the gasifier, where a reaction takes place to form two main products: synthetic gas (syngas) and slag. Full-load feed rates of solid feedstocks (coal/petcoke/fluxant) will range from 2,000 to 5,000 tons per day, as the feed rate to maintain the gasifier at the required temperature will depend on the quality of the feedstock. Part-load feed rates will be based on the operating limitations of the gasifier, which is dependent upon the quality of the feedstock. Typical gasifiers have a turndown rate of about 50 percent.

Syngas Composition

The syngas is composed primarily of hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2) and water vapor, plus small amounts of hydrogen sulfide (H_2S), carbonyl sulfide (COS), nitrogen, ammonia (NH_3), argon, and methane (CH_4). Unreacted feedstock still in solid form, called char, will also be entrained in the hot syngas. The gasifier operating temperature is well above the melting point of most ash constituents that may be present in the feedstock. These metals may be entrained in the syngas. Due to the conditions in the gasifier, almost all of the sulfur is present as H_2S and COS, and the lack of nitrogen significantly reduces the formation of nitrogen oxides (NO_x).

Syngas Cleanup Train

The *quench section of the gasifier* cools the syngas and also serves as a particulate removal step. The syngas and molten slag exit the bottom of the gasifier and into the quench vessel.

After the quench, the syngas is *scrubbed with sour water* to remove trace metals and chlorides. “Sour” indicates that the water contains sulfur compounds. Most of the ammonia remaining in the syngas, along with a small portion of the CO_2 and H_2S are removed with this water. The sour water is then condensed out of the syngas and sent to the sour water treatment unit.

After the sour water scrubber, the syngas will pass through *activated carbon beds*, which will be set up to remove mercury. Typical mercury adsorbers operate such that most of the mercury remaining in the syngas is captured in the activated carbon. After passing through the activated carbon adsorbers, the syngas is sent to the water-gas shift reactors.

After the initial syngas treatment, the syngas will undergo a *sour water-gas shift* reaction to maximize the amount of hydrogen for ammonia production and to convert most of the remaining COS in the syngas to H_2S to maximize sulfur removal in a later step.

Selexol® *acid gas removal* (AGR) technology will be used to remove the H_2S from the syngas and to separate the CO_2 from the hydrogen stream. Several gas streams are produced by the Selexol acid gas removal unit:

AGR Stream 1. The acid gas waste stream consisting primarily of H_2S and CO_2 will be routed to a pollution control device to remove the H_2S before being exhausted to the atmosphere. The control for sulfur compounds will depend on which operating scenario selected by the applicant:

Operating Scenario #1. A Claus Sulfur Recovery Unit is used to remove the sulfur compounds from the H_2S acid gas stream. Tailgas produced in the Claus unit will be recycled to the inlet of the Selexol AGR unit, which eliminates the emission points typically associated with a Claus unit. The sulfur removed using the Claus unit is in the form of elemental sulfur, a saleable byproduct.

Operating Scenario #2. A Haldor-Topsoe wet sulfuric acid plant will be used to remove the sulfur compounds from the H_2S acid gas stream. Tailgas produced in the wet sulfuric acid plant will be routed through a gas cleanup unit consisting of a quench tower, a scrubber, and a mist filter to remove most of the remaining sulfur compounds in this gas stream. The gas then passes through a selective catalytic reduction (SCR) unit to reduce the NO_x emissions before being exhausted to the atmosphere. The sulfur removed using the Haldor-Topsoe technology is in the form of concentrated sulfuric acid (93 to 98.5 weight percent), a saleable byproduct.

AGR Stream 2. Two acid gas waste streams consisting primarily of CO_2 will be produced from the Seloxol unit. One will be reused as feedstock for the urea process, and the other will be treated in a thermal oxidizer before being exhausted to the atmosphere. The thermal oxidizer will provide a minimum 90% control for the H_2S and COS (which will be oxidized to SO_2) and CO (which will be oxidized to CO_2) remaining in this gas stream.

AGR Stream 3. Hydrogen-rich syngas.

Startup/Upsets: During startups of the gasifier, the hydrogen-rich syngas will first pass through the sour water scrubber, the activated carbon beds, and an amine scrubber to reduce the sulfur content, and then will be sent to the gasifier flare.

Normal Operations: From the Selexol unit, the hydrogen-rich syngas goes to a pressure swing adsorber (PSA) unit, where the hydrogen is separated from the other syngas components, producing a very pure stream of hydrogen. This hydrogen stream is sent to the ammonia synthesis loop.

The remaining syngas, or "PSA tailgas," may be used in a "maximum recycle mode" or as supplemental fuel to the boilers. A majority of this tailgas may be recycled to the water-gas shift reactors so that the H_2 can be used in fertilizer production. In addition, up to 100% of the PSA tailgas may be used to supplement natural gas being burned in the steam superheater boiler (Operating Scenario #1) or in the package boiler (Operating Scenario #2).

7.2 Emissions Control Description

Table 7.1 GASIFICATION ISLAND DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Gasifier #1 and Gasifier #2 Gasifier and Quench Vessel Manufacturer/Model: GE Quench gasifier Capacity: Up to 5,000 TPD coal/petcoke blend Feedstock: Maximum 6% sulfur coal/petcoke blend Coal/petcoke/fluxant wet slurry O_2 (from the ASU)	Control: None	Fugitive (pipe/valve leak) emissions only.

Table 7.1 GASIFICATION ISLAND DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Syngas Cleanup Train: Sour Water Scrubber Manufacturer/Model: TBD Scrubbing media: sour water Activated Carbon Beds (Mercury (Hg) Removal) Manufacturer/Model: TBD Capture Efficiency: 95% reduction from Hg levels present in the feedstock.	Startup/Upsets: Amine Scrubber: Manufacturer/Model: TBD Feedstock: sour syngas from activated carbon beds Purpose: Control sulfur compound emissions Scrubber Parameters: TBD Efficiency: 95% removal (as SO_2) Gasifier Flare: Flare type: air or steam assist Pilot fuel: natural gas Flare gas: sweet syngas Maximum capacity: ~900,000 lb/hr of sweet syngas Operations: 8,760 hr/yr Efficiency: 98% for CO Normal Operations: None	Gasifier Flare Stack Parameters, SRC16: Stack Height: 65.0 m (213.3 ft) Exit Diameter: 0.38 m (0.92 ft) Orientation: vertical Exit flow rate: 182 acfm Exit Velocity: 20.0 m/sec Exit Temperature: 1,273 K (1,832 ^oF) Fugitive (pipe/valve leak) emissions only.
Syngas Cleanup Train: Selexol® Acid Gas Removal Unit AGR Stream 1: H_2S and CO_2	Operating Scenario #1 Claus Sulfur Recovery Unit: Manufacturer/Model: TBD Tailgas Handling: Hydrotreater to Sour Shift inlet	Fugitive (pipe/valve leak) emissions only.
Syngas Cleanup Train: Selexol® Acid Gas Removal Unit AGR Stream 1: H_2S and CO_2	Operating Scenario #2 Wet Sulfuric Acid Plant: Manufacturer: Haldor-Topsoe Quench Tower/Scrubber/Mist Filter Manufacturer/Model: Haldor-Topsoe Purpose: H_2SO_4 and SO_2 reduction Operating Parameters: TBD Efficiency: TBD SCR (within WSA unit) Manufacturer: Haldor-Topsoe Purpose: NO_x reduction Efficiency: 90.9% (to 10 ppm NO_x) Ammonia slip: $\leq$ 10 ppmv (dry), corrected to 15% O_2	Sulfuric Acid Vent Stack Parameters, SRC18: Stack Height: 50 m (164 ft) Exit Diameter: 1.9 m (6.3 ft) Orientation: vertical Exit flow rate: 109,000 acfm Exit Velocity: 18.0 m/sec Exit Temperature: 419 K (294.5 ^oF) Fugitive (pipe/valve leak) emissions.
Syngas Cleanup Train: Selexol® Acid Gas Removal Unit AGR Stream 2: CO_2 Vent (CO, H_2S, and COS/VOCs)	Thermal Oxidizer: Mfr/Model: CSM Worldwide, Model 510A Maximum Capacity: 300,000 lb/hr CO_2 Burner Type: Direct-fired Rating: 9 MMBtu/hr Fuel: Natural gas Catalyst: Type: Low-Temperature Life: ~ 3-5 years Cleaning Frequency: ~ 6 months Cleaning Method: offsite regeneration Operations: 8,760 hr/yr Efficiency: 90% H_2S, COS, and CO	Selexol AGR CO_2 Vent Stack Parameters, SRC17 Stack Height: 52.0 m (171 ft) Exit Diameter: 1.34 m (4.4 ft) Orientation: vertical Exit flow rate: 54,000 acfm Exit Velocity: 18.0 m/sec Exit Temperature: 359 K (186.5^oF)

Table 7.1 GASIFICATION ISLAND DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Syngas Cleanup Train: Selexol® Acid Gas Removal Unit AGR Stream 3: Syngas Syngas Stream: H_2 (90 mole%), CO_2 (5 mole%), CO, methane, inerts, and < 1 ppm H_2S and COS	Normal Operations: None.	Normal Operations: Fugitive (pipe/valve leak) emissions only.
Syngas Cleanup Train: Pressure Swing Adsorber (PSA)	None.	Fugitive (pipe/valve leak) emissions only.

Emissions Limits

7.3 Emissions Limits (BACT)

The PM, PM_{10}, SO_2, NO_X, VOC, and CO emissions from the stacks identified in Table 7.2 shall not exceed any corresponding emissions rate limits listed in that table.

Table 7.2 GASIFICATION ISLAND EMISSIONS LIMITS (BACT) [1]

Source Description	PM		PM_{10} [2]		SO_2		NO_X		VOC		CO	
	lb/hr [3]	T/yr [4]	lb/hr [3]	T/yr [4]	lb/hr	T/yr [4]	lb/hr [3]	T/yr [4]	lb/hr	T/yr [4]	lb/hr [3]	T/yr [4]
Operating Scenario #2. Sulfuric Acid Vent	---	---	---	---	2.2	9.8	4.0	17.6	---	---	6.8	29.9
Selexol AGR Stream 2: CO_2 Vent	---	---	---	---	3.6	15.6	0.9	3.9	---	---	17.3	75.9

1) In the absence of any other creditable evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements**. Lb/hr limits are BACT.**
2) Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.
3) As determined by source test methods prescribed by IDAPA 58.01.01.157.
4) Tons per any consecutive 12-calendar month period.

Operating Requirements

7.4 Gasifier Feedstock

7.4.1 The permittee shall install, calibrate, and operate a means to monitor and record the weight of the coal, petcoke, and fluxant fed to the gasifier, individually and combined, in tons per day.

7.4.2 Solid feedstock to the gasifiers shall not contain more than**:**

- 6.0% sulfur by weight as blended, based on the as-received sulfur content of the coal, petcoke, and fluxant,

  or

- The sulfur content of the solid feedstock blend used to produce the syngas for any performance test conducted within the previous five (5) year period that demonstrated compliance with applicable SO_2 emission limits for the wet sulfuric acid plant (if installed), and the SO_2 emissions from the gasifier flare when burning syngas and for worst-case normal operating conditions.

7.4.3 The sulfur content of the solid feedstock shall be calculated based on the as-received sulfur content of the coal, petcoke, and fluxant.

7.4.4 The amount of coal and petcoke fed to the gasifiers shall not exceed 5,000 tons per day of blended coal and petcoke and 250 tons per day of fluxant.

7.4.5 The operating level of the gasifier(s) shall not at any time exceed the actual working capacity of the syngas cleanup train.

7.5 Syngas Cleanup Train

7.5.1 The permittee shall install, maintain, and operate a syngas cleanup train **during startup** or shutdown operations as follows:

- A sour water scrubber to remove metals and chlorides from the syngas stream,
- Activated carbon beds to remove mercury from the syngas stream. Mercury contained in the syngas stream after passing through the activated carbon beds shall not exceed five (5) percent of the mercury present in the feedstock.
- An amine scrubber with a minimum 95% capture efficiency for sulfur compounds (COS and H_2S as SO_2) to treat the syngas stream prior to being flared, and
- **An elevated flare (the gasifier flare)** that:
  - Meets all applicable requirements of 40 CFR 60.18;
  - Is served by a pilot that burns natural gas exclusively;
  - Is operated at all times in accordance with good combustion practices; and
  - A system shall be installed, maintained, and operated that will record the date, time, duration of each occurrence of venting of syngas to the flare, and total flow of syngas and pilot gas in scfm to the flare, whenever syngas is vented to the gasifier flare; and
  - During startup and shutdown, operating the gasifer flare in accordance with this permit condition is considered BACT for this source.
- Syngas that has not passed through any part of the syngas cleanup train shall not be flared except when a malfunction precludes the safe processing of the syngas in the cleanup train.

7.5.2 The permittee shall install, maintain, and operate a syngas cleanup train **during normal operations** as follows:

- A sour water scrubber to remove metals and chlorides from the syngas stream,
- Activated carbon beds to remove mercury from the syngas stream. Mercury contained in the syngas stream after passing through the activated carbon beds shall not exceed five (5) percent of the mercury present in the feedstock.
- An acid gas removal (AGR) system to remove sulfur compounds from the syngas stream, and

- The portion of the CO_2-rich stream from the AGR (AGR Stream 2) that is not recycled to the AGR process or routed to the urea process shall be sent through a thermal oxidizer with a minimum capture efficiency of 90% for CO and for sulfur compounds including H_2S and COS, before being exhausted to the atmosphere,

  and

- Operating Scenario #1. Sulfur compounds from the H_2S-rich stream from the AGR unit (AGR Stream 1) shall be removed using a Claus sulfur recovery unit.
  - Tailgas from the Claus sulfur recovery unit shall be treated and returned to the inlet of the acid gas removal (AGR) unit.

  or

- Operating Scenario #2. Sulfur compounds from the H_2S-rich stream from the AGR (AGR Stream 1) shall be removed using a Haldor-Topsoe wet sulfuric acid plant before being exhausted to the atmosphere.
  - Tailgas produced in the wet sulfuric acid plant shall be routed through a gas cleanup unit consisting of a quench tower, a scrubber, and a mist filter to remove most of the remaining sulfur compounds in this gas stream.
  - The tailgas shall then pass through a selective catalytic reduction (SCR) unit with a minimum NO_x removal efficiency of 90.9%.
  - The ammonia slip for the SCR unit in the Haldor-Topsoe wet sulfuric acid plant shall not exceed 10 ppmv (dry), converted to 15% oxygen.

7.5.3 The syngas cleanup train shall be operated at all times when the gasifier(s) are being operated.

7.5.4 The syngas cleanup train described in this permit condition is considered BACT for these emission sources.

7.6 Startup, Shutdown, and Scheduled Maintenance (SSM) Plan

7.6.1 In accordance with IDAPA 58.01.01.133.02, the permittee shall develop and submit a Startup, Shutdown, and Scheduled Maintenance (SSM) Plan that meets the requirements of Sections 133.02 and 133.03. The plan shall include, but not be limited to procedures necessary to:

- Minimize the frequency of gasifier shutdowns (thereby reducing the number of startups),
- Prevent the occurrence of malfunctions,
- Prevent the flaring of acid gas or other gases containing sulfur compounds, and
- Minimize the quantity of emissions of all pollutants at all times, including periods of startup, shutdown, malfunction, and scheduled maintenance.

7.6.2 The permittee shall submit the SSM Plan to DEQ not later than 60 days prior to the initial startup of either of the gasifiers.

Monitoring and Recordkeeping Requirements

7.7 Throughput Monitoring

The permittee shall monitor and record:

- The amount of coal, petcoke, and fluxant fed to the gasifiers, in tons per day.

- The sulfur content of the feedstock blend fed to the gasifiers, in percent by weight. The sulfur content of the feedstock blend shall be calculated based on the as-received sulfur content and amount fed that day for each of the feedstocks.
- Records of this information shall be maintained in accordance with General Provision 7.

7.8 Gasifier Flare Testing and Monitoring

7.8.1 Within 10 days of initial startup of any of the units in the gasification island, the permittee shall conduct tests consistent with 40 CFR 60.18 to confirm that the gasification flare is being operating using good combustion practices.

7.8.2 The permittee shall maintain the records of the gasifier flare parameters listed in Permit Condition 7.5.1 in accordance with General Provision 7.

7.9 Option #2 SCR Unit Monitoring

The permittee shall monitor and record the SCR ammonia slip listed in Permit Condition 7.5.2, and shall maintain these records in accordance with General Provision 7.

7.10 Syngas Monitoring

7.10.1 Within 60 days of the initial startup of either gasifier, the permittee shall obtain and analyze representative samples of the syngas stream that is being vented to the gasifier flare. Sampling shall be conducted during one representative one-hour period during startup conditions when syngas is being flared. The sample report shall include, but not be limited to, the source(s), type, and amount of the solid feedstock being fed to the gasifier during the test, operating parameters for the sour water scrubber, activated carbon beds, and amine scrubber, the syngas and natural gas flow rates in scfm, the combined heating value of the gas(es) being combusted, and the visible emissions observed from the flare using Method 22 of Appendix A to 40 CFR 60.

7.10.2 After the initial sampling and analysis, the permittee shall obtain and analyze representative samples of the syngas stream being vented to the gasifier flare within 60 days of a change in the source of the feedstock. Sampling shall be conducted during one representative one-hour period during startup conditions when syngas is being flared. The sample report shall include the same information, as a minimum, as described in Permit Condition 7.10.1. If there has been no change in feedstock, the permittee shall conduct such sampling at least once in every two year period.

8. AMMONIA AND UREA PLANTS

8.1 Process Description

Permit Conditions 8.1 and 8.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

Ammonia is produced by combining the high-purity hydrogen stream from the Selexol AGR unit with high-purity nitrogen from the ASU. Using the Haber process, hydrogen and nitrogen are reacted over an iron catalyst to produce ammonia. The hot ammonia stream that results is cooled through a series of heat exchangers, eventually using refrigerated ammonia to cool and condense the product ammonia from a gas to a liquid. The synthesis loop will have a capacity of approximately 2,000 tons per day of ammonia. Most of this will be used to produce urea, nitric acid, ammonium nitrate, and UAN. The remainder will be sold as a product.

The liquid product ammonia produced in the ammonia synthesis loop is sent to the ammonia refrigeration system. The pressure is reduced to close to atmospheric in a flash vessel, which causes additional cooling. The vapors from this drum leave the system as off-gas and are routed to the process flare (also called the ammonia flare). These vapors need to be purged to prevent the buildup of inert gases such as argon in the circulating gas system. The liquid ammonia from the flash vessel is split, with a portion going to feed the urea process, and the rest sent to additional flash drums. Ammonia not needed in the refrigeration cycle for ammonia synthesis is sent to the atmospheric cold product ammonia tanks.

Urea will be produced using Stamicarbon technology, or another similar commercially available process, from ammonia and from purified CO_2 from the Selexol AGR unit. In an intermediate step, urea leaving the decomposers is concentrated in the evaporation section of the process into a melt. Emissions from this step are vented to the atmosphere through the urea melt plant vent. The urea process results in a liquid stream of urea, with process off-gases vented to the process flare (also referred to as the ammonia flare).

Granulated urea will be produced using Uhde technology, or similar commercially proven technology. In the granulator, the urea solution is injected from the bottom through dispensers that atomize it upwards into a bed of moving particles. These moving particles are fines that have been recycled from the process and are the seed particles that begin the growth of the granules. Formaldehyde is used as a seeding agent for this process. The granules form via accretion, a process in which tiny droplets solidify onto the seed particles. When the liquid solidifies, heat is released.

The granules that form flow out of the granulator to a fluid bed cooler that uses air as the cooling medium. The granules are then lifted by a bucket elevator to the screening section. Here screening takes place to separate the granules that are the correct size from smaller particles. The on-spec granules are sent to a second air-cooler for further cooling prior to being sent to humidity-controlled storage, which prevents the final product from caking.

The smaller particles are split into fines and coarse material. The fines are recycled directly to the granulator as seed particles, while the coarse material is first crushed and then used as seed particles.

sThe urea spray is aided by fluidization air, which flows through the product layer and is exhausted at the top of the granulator. The air exiting the granulator and the coolers contains some urea dust, which is removed using a scrubber. Ammonia in the urea feed solution will be released in the granulator and will be absorbed in an acidic scrubbing system. The ammonia is recovered as an ammonium salt.

8.2 Emissions Control Description

Table 8.1 AMMONIA AND UREA PLANTS DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Ammonia Synthesis Loop and Refrigeration System Capacity: ~2,000 tons per day (ammonia)	Process Flare: Flare type: air or steam assist Pilot fuel: natural gas Flare gas: Ammonia system purge gases and urea process off-gases	Process Flare Stack Parameters, SRC21: Stack Height: 52.0 m (171 ft) Exit Diameter: 0.43 m (1.4 ft) Orientation: vertical Exit flow rate: 252 acfm Exit Velocity: 20.0 m/sec Exit Temperature: 1,273 K (1,832 ^{o}F) Fugitive (pipe/valve leak) emissions.
Urea Process: Stamicarbon or equivalent. Urea reactor vessel, steam stripper, decomposers, evaporator(s), ammonia receiver/condenser, carbamate absorber/condensers, multi-stage compressor(s), pumps, valves, piping, and instrumentation. Capacity: 2,400 tons per day (liquid solution)	None.	Urea Melt Plant Vent Stack Parameters, SRC23: Stack Height: 34.0 m (112 ft) Exit Diameter: 1.22 m (4.0 ft) Orientation: vertical Exit flow rate: 136,900 acfm Exit Velocity: 55.3 m/sec Exit Temperature: 318 K (112.7 ^{o}F) Fugitive (pipe/valve leak) emissions.
Urea Process, continued	Process Flare: Flare type: air or steam assist Pilot fuel: natural gas Flare gas: Ammonia system purge gases and urea process off-gases	Process Flare Stack Parameters, SRC21: - see above - Fugitive (pipe/valve leak) emissions.
Urea Granulation: Uhde or equivalent. Capacity: 1,800 tons per day granulated urea	Wet Scrubber Manufacturer/Model: TBD Purpose: Ammonia and PM reduction Scrubber Parameters: TBD Efficiency: 98%	Granulation Vent Stack Parameters, SRC19: Stack Height: 40 m (131ft) Exit Diameter: 1.8 m (6.0 ft) Orientation: vertical Exit flow rate: 296,500 acfm Exit Velocity: 53.3 m/sec Exit Temperature: 323 K (121.7^{o}F) Fugitive (pipe/valve leak) emissions.

Emissions Limits

8.3 Emissions Limits

The PM, PM_{10}, SO_2, NO_X, CO, and VOC emissions from the urea granulation stack shall not exceed any corresponding emissions rate limits listed in Table 8.2.

Table 8.2 AMMONIA AND UREA PLANT EMISSIONS LIMITS

Source Description	PM		PM_{10}		SO_2		NO_X		VOC		CO	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Urea Granulation Vent Stack (BACT limits)	20.5	---	9.0	39.4	---	---	---	---	---	---	---	---

1) In the absence of any other creditable evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements**. Lb/hr limits are BACT.**
2) Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.
3) As determined by source test methods prescribed by IDAPA 58.01.01.157.
4) Tons per any consecutive 12-calendar month period.

Operating Requirements

8.4 Production Limits

The production of granular urea shall not exceed:

- 1,800 tons per day,

  or

- The daily production of granular urea achieved for any performance test conducted within the previous five (5) year period that demonstrated compliance with applicable PM and PM_{10} emission limits listed in Table 8.2 for the urea granulation vent stack.

8.5 Process Flare

The process flare shall be an elevated flare that:

- Meets all applicable requirements of 40 CFR 60.18;
- Is served by a pilot that burns natural gas exclusively;
- Is operated at all times in accordance with good combustion practices; and
- A system shall be installed, maintained, and operated that will record the date, time, duration of each occurrence of venting of gases to the flare, and total flow of vented gases and pilot gas in scfm to the flare, whenever process gas is vented to the process flare; and
- To control excess buildup of hazardous gases in the ammonia and urea production processes, operating the process flare in accordance with this permit condition is considered BACT for this source.

Monitoring and Recordkeeping Requirements

8.6 Production Monitoring and Recordkeeping

The permittee shall monitor and record the production of granular urea in tons per day. Records of this information shall be maintained in accordance with General Provision 7.

8.7 Monitoring and Recordkeeping (NSPS, 40 CFR 60, Subpart VVa)

The permittee shall comply with the applicable monitoring and recordkeeping requirements of 40 CFR 60.480a through 60.489a for the urea process unit, i.e., for all components assembled and connected by pipes or ducts to process raw materials and to produce urea as an intermediate or final product **that are in VOC service**. For the purposes of Subpart VVa, the urea process unit includes any feed, intermediate and final product storage vessels (except as specified in 40 CFR 60.482-1a(g)), product transfer racks, and connected ducts and piping. In accordance with 60.481a, a process unit includes all equipment, meaning each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required under Subpart VVa.

8.8 Initial Performance Tests (NSPS, 40 CFR 60, Subpart VVa)

In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which urea process unit will be operated, but not later than 180 days after the initial startup of the urea process unit, the permittee shall conduct performance test(s) for the affected facility in accordance with the test methods and procedures specified in 40 CFR 60.485a.

Reporting Requirements

8.9 Construction and Initial Startup Notification (NSPS, 40 CFR 60, Subpart A, General Provisions)

The permittee shall submit notification of the date that construction commences (postmarked no later than 30 days after such date), and the date of initial startup (postmarked no later than 15 days after such date), in accordance with 40 CFR 60.7(a)(1) and 60.7(a)(3).

8.10 Reporting (NSPS, 40 CFR 60, Subpart VVa)

In accordance with 40 CFR 60.487a, the permittee shall submit semiannual reports to the EPA (until such time as DEQ is delegated this NSPS) beginning 6 months after the initial startup date. Information included in the semiannual reports shall comply with 60.487a.

9. NITRIC ACID AND AMMONIUM NITRATE/UAN PLANTS

9.1 Process Description

Permit Conditions 9.1 and 9.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

The project will manufacture urea ammonium nitrate (UAN) for sale. Nitric acid and ammonium nitrate are intermediate products that are required to manufacture UAN, which is made by combining ammonium nitrate solution with urea solution produced in the urea plant.

Nitric acid is produced by reacting ammonia from the ammonia plant with oxygen (from the ambient air) and water. The nitric acid plant will produce weak nitric acid at a concentration of about 57 percent, which will be stored in a tank or sent directly to the ammonium nitrate process. Tailgas produced in the nitric acid plant will consist mainly of nitrogen, oxygen, and carbon dioxide. The tailgas is cooled, used to run an air compressor turbine, and then mixed with abatement air. The tailgas passes through a selective catalytic reduction (SCR) system to reduce the NO_x before being exhausted to the atmosphere.

Ammonium nitrate is produced by reacting nitric acid in a neutralizer/scrubber where ammonia from the ammonia plant is added to neutralize the nitric acid. The liquid that forms is ammonium nitrate and water, and the vapor is primarily water and CO_2. A stream of the ammonium nitrate and water is taken from the neutralizer and mixed with a portion of the nitric acid feed. This liquid is used to scrub the vapor before leaving the neutralizer/scrubber. The vapor is then sent to a process condensate tank, where it is cooled, and most of the water is condensed. The remaining gas, consisting primarily of CO_2 and some steam, is vented from the process condensate tank. The ammonium nitrate is then mixed with urea to form a UAN solution. The UAN is sent to storage tanks to be shipped out by rail or truck for sale.

9.2 Emissions Control Description

Table 9.1 NITRIC ACID AND AMMONIUM NITRATE/UAN PLANTS DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Nitric Acid Plant Manufacturer/Provider: Weatherly or equivalent Capacity: ~575 TPD of nitric acid	SCR: Manufacturer/Model: TBD Operating Parameters: TBD Efficiency: 98% for NO_x Ammonia slip: $\leq$ 10 ppmv (dry), corrected to 15% O_2	Nitric Acid Tailgas Stack Parameters, SRC20: Stack Height: 58.0 m (190 ft) Exit Diameter: 1.16 m (3.8 ft) Orientation: vertical Exit flow rate: 60,500 acfm Exit Velocity: 27.1 m/sec Exit Temperature: 400 K (260.3 ^oF) Fugitive (pipe/valve leak) emissions.
Ammonium Nitrate/UAN Plant Manufacturer/Provider: Weatherly or equivalent Capacity: ~715 TPD of ammonium nitrate ~1,600 TPD of UAN	None. The scrubber is integral to the process.	AN Neutralizer Vent Stack Parameters, SRC29: Stack Height: 16.0 m (52.5 ft) Exit Diameter: 0.3 m (1.0 ft) Orientation: vertical Exit flow rate: 14,123 acfm Exit Velocity: 91.4 m/sec Exit Temperature: 344 K (159.5 ^oF) Fugitive (pipe/valve leak) emissions.

Emissions Limits

9.3 Emissions Limits (BACT)

The PM, PM_{10}, and NO_X emissions from the nitric acid tailgas stack and the ammonium nitrate neutralizer vent shall not exceed any corresponding emissions rate limits listed in Table 8.2.

Table 9.2 NITRIC ACID AND AMMONIUM NITRATE/UAN PLANTS EMISSIONS LIMITS[1]

Source Description	PM		PM_{10}		SO_2		NO_X		VOC		CO	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Nitric Acid Tailgas Vent (lb/hr limits are BACT limits)	---	---	---	---	---	---	15.3	61.16	---	---	---	---
AN Neutralizer Vent (BACT limits)	1.5	---	1.5	6.52	---	---	---	---	---	---	---	---

1) In the absence of any other creditable evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements**. Lb/hr emissions are BACT limits. T/yr emissions represent modeled values.**
2) Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.
3) As determined by source test methods prescribed by IDAPA 58.01.01.157.
4) Tons per any consecutive 12-calendar month period.

9.4 Emissions Limits for the Nitric Acid Production Unit (NSPS, 40 CFR 60, Subpart G)

In accordance with 40 CFR 60.72(a), on and after the date on which the performance test required to be conducted by 60.8 is completed, emissions from the nitric acid production unit shall not:

- Contain nitrogen oxides, expressed as NO_2, in excess of 1.5 kg per metric ton of acid produced (3.0 lb per ton), the production being expressed as 100 percent nitric acid.
- Exhibit 10% opacity or greater.

Operating Requirements

9.5 Nitric Acid Tailgas Pollution Control Equipment

9.5.1 The permittee shall install, maintain, and operate a selective catalytic reduction (SCR) system to control NO_x emissions from the nitric acid production unit tailgas.

9.5.2 The SCR system shall be operated at all times when the nitric acid production unit is being operated.

9.5.3 The ammonia slip for the SCR system shall not exceed 10 ppmv (dry) converted to 15% oxygen.

Monitoring and Recordkeeping Requirements

9.6 Production Rate and Operating Hours Monitoring(NSPS, 40 CFR 60, Subpart G)

9.6.1 In accordance with 40 CFR 60.73(c) the permittee shall record the daily production rate and hours of operation for the nitric acid production unit (NSPS, 40 CFR, Subpart G).

9.6.2 Records shall be maintained in accordance with General Provision 7.

9.7 Emissions Monitoring for NOx for the Nitric Acid Production Unit (40 CFR 60, Subpart G)

9.7.1 In accordance with 40 CFR 60.73(a), the permittee shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides (NO_x) emissions from the nitric acid production unit. The pollutant gas mixtures under Performance Specification 2 and for calibration checks under 60.13 of this part shall be nitrogen dioxide (NO_2). The span value shall be 500 ppm of NO_2. Method 7 of Appendix A to 40 CFR 60 shall be used for the performance evaluations under 60.13(c). Acceptable alternative methods to Method 7 are given in 60.74(c).

9.7.2 In accordance with 40 CFR 60.73(b), the permittee shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/ton).

- The conversion factor shall be established by measuring emissions with the continuous monitoring system concurrent with measuring emissions with the applicable reference method tests.
- The conversion factor shall be reestablished during any performance test under 60.8 or any continuous monitoring system performance evaluation under 60.13.

9.8 Initial Performance Test, Nitric Acid Production Unit (NSPS, 40 CFR 60, Subpart A)

In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the nitric acid production unit will be operated, but not later than 180 days after the initial startup of the nitric acid production unit, the permittee shall conduct performance test(s) to demonstrate compliance with the:

- NO_x and opacity limits and listed in Permit Condition 9.4.

Reporting Requirements

9.9 Construction and Initial Startup Notification (NSPS, 40 CFR 60, Subpart A, General Provisions)

The permittee shall submit notification of the date that construction of the nitric acid production unit commences (postmarked no later than 30 days after such date), and the date of initial startup of the nitric acid production unit (postmarked no later than 15 days after such date), in accordance with 40 CFR 60.7(a)(1) and 60.7(a)(3).

9.10 Excess Emissions Reporting for Nitric Acid Production Unit (NSPS, 40 CFR 60, Subpart G)

In accordance with 40 CFR 60.73(d) for the purpose of reports required under 60.7(c), periods of excess emissions from the nitric acid production unit that shall be reported are defined as any 3-hour period during which the average NO_x emissions (arithmetic average of three contiguous 1-hour periods) as measured by a continuous monitoring system exceed the standard listed in Permit Condition 9.4.

10. DIESEL, AMMONIA, ACID, AND UAN TANK STORAGE

10.1 Process Description

Permit Conditions 10.1 and 10.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

Diesel fuel for the emergency engine generators will be delivered by truck and stored in horizontal fuel tanks.

Ammonia produced in the ammonia synthesis loop will be used in the next steps of the fertilizer production process or will be stored onsite before being shipped offsite for sale. The ammonia storage facility will consist of two insulated tanks at atmospheric pressure with refrigeration systems to maintain the ammonia at the required temperature of -33^{o}F. In the refrigeration system, ammonia vapor is compressed by electrically-powered storage compressors from the top of the tank and condensed by fresh cooling water. Expansion of the compressed ammonia provides the refrigeration necessary to maintain the low temperatures. The condensed liquid ammonia is returned to the storage tanks. The refrigeration unit will include redundant equipment to ensure the refrigeration system is always in operation.

Nitric acid from the nitric acid production unit will either be stored in a tank and/or fed to the ammonium nitrate production process.

For Operating Scenario #2, a Haldor-Topsoe wet sulfuric acid plant will be used to remove sulfur compounds from the H_2S waste stream produced by the Selexol acid gas removal (AGR) unit. The concentrated sulfuric acid will be piped from the wet sulfuric acid plant into either of two storage tanks. To prevent sulfuric acid vapors from building up in the tanks, each tank will have a nitrogen blanket, i.e., the space between the surface of the sulfuric acid and the top of the tank will be filled with nitrogen.

Urea ammonium nitrate produced in the UAN plant will be stored on site in one of four storage tanks. The tanks will be at atmospheric pressure. UAN will be loaded into railcars or tanker trucks directly from the tanks.

10.2 Emissions Control Description

Table 10.1 FUEL AND LIQUID PRODUCT TANK STORAGE DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Emergency Engine Generator Fuel Tank Tank 19, Diesel Storage Tank Contents: #2 Diesel fuel Capacity: 3,000 gallons Turnovers: 1 per year Type: Horizontal Shell length: 10.0 ft Shell Diameter: 7.50 ft Paint: Gray/Light Paint Condition: Good	None.	Tank vent(s)

Table 10.1 FUEL AND LIQUID PRODUCT TANK STORAGE DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Emergency Fire Pump Engine Fuel Tank Tank 18, Diesel Storage Tank Contents: #2 Diesel fuel Capacity: 500 gallons Turnovers: 1 per year Type: Horizontal Shell length: 5.0 ft Shell Diameter: 5.0 ft Paint: Gray/Light Paint Condition: Good	None.	Tank vent(s)
Ammonia Storage Tanks (2) Capacity: 204,000 barrels (each) (6.426 million gallons each) Type: Vertical fixed roof Insulated atmospheric pressure tanks Size: Shell height 41 ft, Diameter 45 ft Service Equipment: Ammonia compressors Fuel: Electric utility	Flare	Ammonia Storage Flare Parameters, SRC27: Stack Height: 18.29 m (60.0 ft) Exit Diameter: 0.20 m (0.66 ft) Orientation: vertical Exit flow rate: 129 acfm Exit Velocity: 20.0 m/sec Exit Temperature: 1,273 K (1,832^{o}F)
Nitric Acid Storage Tank Capacity: 16,000 barrels (504,000gallons) Type: Vertical fixed roof Atmospheric pressure tank Size: Shell height 45 ft, Diameter 50 ft	None.	Tank vent(s)
Operating Scenario #2 Sulfuric Acid Storage Tanks (4) Contents: Concentrated sulfuric acid Capacity: 27,000 barrels (each) (850,500 gallons each) Type: Vertical fixed roof Atmospheric pressure tanks Size: Shell height 45 ft, Diameter 65 ft Cover Gas/Blanket: Nitrogen	None.	Tank vent(s)
UAN Storage Tanks (4) Contents: UAN Capacity: 110,000 barrels (each) (4.5 million gallons each) Type: Vertical fixed roof Atmospheric pressure tanks Size: Shell height 42 ft, Diameter 130 ft	None.	Tank vent(s)

Operating Requirements

10.3 Ammonia Storage

10.3.1 The ammonia storage tanks shall include a nitrogen cover gas in the headspace of the tank, and shall be vented to the ammonia storage flare.

10.3.2 The ammonia storage flare shall be an elevated flare that:

- Meets all applicable requirements of 40 CFR 60.18;
- Is served by a pilot that burns natural gas exclusively;
- Is operated at all times in accordance with good combustion practices; and

- A system shall be installed, maintained, and operated that will record the date, time, duration of each occurrence of venting of ammonia to the flare, and total flow of vented ammonia and pilot gas in scfm to the flare, whenever ammonia is vented to the ammonia storage flare.

11. ZERO LIQUID DISCHARGE SYSTEM (ZLDS) AND COOLING TOWER

11.1 Process Description

Permit Conditions 11.1 and 11.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

Blowdown water from the bottom of the ammonia stripper in the sour water scrubber system, as well as other wastewaters from the project, will be sent to the Zero Liquid Discharge System (ZLDS). A typical ZLD system may include a brine concentrator, which heats and evaporates the water. The water vapor is compressed and condensed, with the high-quality distillate water being recycled to the plant. The concentrated brine is sent to a rotary drum dryer/crystallizer. Here, the remaining water is evaporated, which leaves a solid filter cake material.

The cooling tower will use a wet, mechanical forced-draft design, incorporating seven cells. As the cooling water is used remove heat from various plant processes, it is heated from approximately 75^{o}F to 95^{o}F, which can vary depending upon ambient temperature conditions. The warm cooling water is pumped to the top of a cooling tower cell, and water flows over a series of cooling baffles as gravity pulls it to the basin. As air is forced through the baffles by mechanical fans, a portion of the warm water evaporates, effectively cooling the remaining water supply. During this process, some water droplets and mist are entrained in the airflow, and leave the cooling tower in the form of drift and mist. Since a cooling tower tends to concentrate dissolved solids (within set design parameters), this entrained water becomes a source of particulate matter emissions.

11.2 Emissions Control Description

Table 11.1 ZLDS AND COOLING TOWER DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Zero Liquid Discharge System	Drift/mist eliminators	ZLDS Stack Parameters, SRC30: Stack Height: 8.0 m (26.4 ft) Exit Diameter: 2.3 m (7.54 ft) Orientation: vertical Exit flow rate: 235,387 acfm Exit Velocity: 27.1 m/sec Exit Temperature: 317 K (110.9 ^{o}F)
Cooling Tower	Drift/mist eliminators	Cooling Tower Stack Parameters, SRC22: Stack Height: 13.0 m (42.6 ft) Equivalent Exit Diameter: 22.6 m (74.1 ft) Orientation: vertical Exit flow rate: 1,289,000 acfm Exit Velocity: 8.3 m/sec Exit Temperature: 303 K (85.7 ^{o}F)

Emissions Limits

11.3 Emissions Limits

11.3.1 The PM and PM_{10} emissions from the ZLDS stack and cooling tower shall not exceed any corresponding emissions rate limits listed in Table 11.2.

Table 11.2 ZLDS AND COOLING TOWER EMISSIONS LIMITS

Source Description	PM		PM_{10}		SO_2		NO_X		VOC		CO	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
ZLDS	0.246	1.08	0.246	1.08	---	---	---	---	---	---	---	---
Cooling Tower	1.51	6.62	1.51	6.62	---	---	---	---	---	---	---	---

1) In the absence of any other creditable evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements**. Lb/hr limits are BACT.**
2) Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.
3) As determined by source test methods prescribed by IDAPA 58.01.01.157.
4) Tons per any consecutive 12-calendar month period.

11.3.2 Emissions from the ZLDS stack and cooling tower shall not exceed the applicable process weight rate limit specified in IDAPA 58.01.01.700-701.

Operating Requirements

11.4 Drift/Mist Eliminator Operation

The permittee shall operate the respective drift/mist eliminator control devices at all times when the ZLDS and cooling tower are being operated.

11.5 Cooling Water Solids Content and Flow Rate

The total solids content and flow rate of the water being cooled in the ZLDS and cooling tower shall not exceed the maximum level present during any performance test in the previous five (5) year period that demonstrated compliance with the applicable emissions and opacity limits for that source.

Monitoring and Recordkeeping Requirements

11.6 Cooling Water Solids Content and Flow Rate Monitoring

The permittee shall monitor and record the total solids content and flow rate of the water being cooled in the ZLDS and cooling tower on a daily basis, to ensure compliance with Permit Condition 11.5.

11.7 PM and PM_{10} Emission Compliance Testing

11.7.1 Within 180 days after the initial startup of the ZLDS and cooling tower, whichever occurred first, the permittee shall conduct a performance test on the ZLDS stack and cooling tower to demonstrate compliance with:

- The pound per hour PM and PM_{10} (including condensables) emission limits specified in Table 11.2,
- The applicable process weight rate limit specified in Permit Condition 11.3.2, and
- The opacity limit specified in Permit Condition 2.6.

11.7.2 PM emissions shall be determined using Method 5 of Appendix A to 40 CFR 60. PM_{10} emissions shall be determined using Methods 5 and 202 of Appendix A to 40 CFR 60. Opacity shall be determined in accordance with the procedures specified in IDAPA 58.01.01.625.

11.7.3 The permittee is encouraged to submit a source testing protocol to DEQ for approval 30 days prior to conducting the performance test. The source test shall be conducted under "worst case normal" conditions as required by IDAPA 58.01.01.157 and General Provision 6, and the source test report shall contain documentation that the test was conducted under these conditions. General Provision 6 includes notification requirements, testing procedures and reporting requirements.

The permittee shall monitor and record the following during each performance test, at a minimum:

- The total solids content of the water,
- Water flow rate, in gallons per minute, and
- Exhaust flow in acfm (per cell, for the cooling tower).

11.8 Periodic Performance Tests for Particulate Matter

The permittee shall conduct performance tests on the ZLDS stack and the cooling tower at a frequency of no less than once every five years to demonstrate compliance with the PM, PM_{10}, and opacity limits specified in Permit Conditions 11.3 and 2.6.

12. SLAG AND SOLID PRODUCT AND BYPRODUCT HANDLING

12.1 Process Description

Permit Conditions 12.1 and 12.2 provide a general description of this process. These descriptions are for informational purposes only, and are not enforceable conditions of the PTC.

The *quench section of the gasifier* cools the syngas and also serves as a particulate removal step. The syngas and molten slag exit the bottom of the gasifier and into the quench vessel. The molten slag solidifies and settles into a water bath at the bottom of the quench vessel through a lockhopper. The solidified slag then exits the bottom of the quench vessel as a slurry. The coarse slag is separated from the fine slag. The fines, which contain a large amount of unreacted carbon, are treated and may be recycled back to the slurry-preparation area. The coarse slag is transferred to the slag storage pile on conveyors. Most of the recovered water is recycled through a proprietary black/grey water system.

Granular urea is stored in a warehouse and elemental sulfur will be stored in tanks.

12.2 Emissions Control Description

Table 12.1 SLAG AND SOLID PRODUCT AND BYPRODUCT HANDLING DESCRIPTION

Emissions Unit(s) / Process(es)	Emissions Control Device	Emissions Point
Slag Storage and Handling	Storage pile enclosed on 3 sides.	Fugitives
Granular Urea Storage	Storage in humidity-controlled warehouse.	Fugitives
Elemental Sulfur Storage	Storage tank(s)	Fugitives, tank vent(s)

Operating Requirements

12.3 Fugitive Dust Control

Fugitive dusts from these sources shall be controlled in accordance with Permit Condition 2.5.

Monitoring and Recordkeeping Requirements

12.4 Fugitive Dust Monitoring

Fugitive dust inspections and recordkeeping for these sources shall be conducted in accordance with Permit Condition 2.5.

13. PERMIT TO CONSTRUCT GENERAL PROVISIONS

General Compliance

1. The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the Rules for the Control of Air Pollution in Idaho. The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit and the Rules for the Control of Air Pollution in Idaho, and the Environmental Protection and Health Act, Idaho Code §39-101, et seq.

[Idaho Code §39-101, et seq.]

2. The permittee shall at all times (except as provided in the Rules for the Control of Air Pollution in Idaho) maintain in good working order and operate as efficiently as practicable, all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.211, 5/1/94]

3. Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules and regulations.

[IDAPA 58.01.01.212.01, 5/1/94]

Inspection and Entry

4. Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

   a. Enter upon the permittee's premises where an emissions source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;

   b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

   c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

   d. As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

5. The permittee shall furnish DEQ written notifications as follows in accordance with IDAPA 58.01.01.211:

   a. A notification of the date of initiation of construction, within five working days after occurrence;

   b. A notification of the date of any suspension of construction, if such suspension lasts for one year or more;

c. A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date;

d. A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date; and

e. A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.211, 5/1/94]

Performance Testing

6. If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

   All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

   Within 30 days following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

[IDAPA 58.01.01.157, 4/5/00]

Monitoring and Recordkeeping

7. The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Records of monitoring information shall include, but not be limited to the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.211, 5/1/94]

Excess Emissions

8. The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions due to startup, shutdown, scheduled maintenance, safety measures, upsets and breakdowns.

[IDAPA 58.01.01.130-136, 4/5/00]

Certification

9. All documents submitted to DEQ, including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

[IDAPA 58.01.01.123, 5/1/94]

False Statements

10. No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

Tampering

11. No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Transferability

12. This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.209.06.

[IDAPA 58.01.01.209.06, 4/11/06]

Severability

13. The provisions of this permit are severable, and if any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[IDAPA 58.01.01.322.15.h, 5/1/94; 40 CFR 70.6(a)(5)]