Statement of Basis

Tier I Operating Permit No. T1-2021.0037
Project ID 63194

Idaho Power Co. - Bennett Mountain
Mountain Home, Idaho

Facility ID 039-00025

Final

November 5, 2023

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The purpose of this Statement of Basis is to set forth the legal and factual basis for the Tier I operating permit terms and conditions, including references to the applicable statutory or regulatory provisions for the terms and conditions, as required by IDAPA 58.01.01.362

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1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BMP	best management practices
Btu	British thermal unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	continuous emission monitoring system
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring system
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
iwg	inches of water gauge
km	kilometers
lb/hr	pounds per hour
m	meters
MACT	Maximum Achievable Control Technology
mg/dscm	milligrams per dry standard cubic meter
MMBtu	million British thermal units
MMscf	million standard cubic feet
MRRR	Monitoring, Recordkeeping and Reporting Requirements
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
PC	permit condition
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers

PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PTC	permit to construct
PTE	potential to emit
PW	process weight rate
QIP	quality improvement plan
RICE	reciprocating internal combustion engines
RMP	risk management plan
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T1/Tier I	Tier I operating permit
T2/Tier II	Tier II operating permit
TAP	toxic air pollutants
T-RACT	Toxic Air Pollutant Reasonably Available Control Technology
ULSD	ultra low sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compound

2. INTRODUCTION AND APPLICABILITY

Idaho Power Co. – Bennett Mountain (Bennett Mountain) generates electric power and is located at 2750 N.E. Industrial Way, Mountain Home, ID. The facility is classified as a major facility, as defined by IDAPA 58.01.01.008, because it emits or has the potential to emit NO_x and CO above the major source threshold of 100 tons-per-year.

At the time of this permitting action, the facility is not a major source of HAP emissions. As a major facility, Idaho Power Co. – Bennett Mountain is required to apply for a Tier I operating permit pursuant to IDAPA 58.01.01.301. The application for a Tier I operating permit must contain a certification from Idaho Power Co. – Bennett Mountain as to its compliance status with all applicable requirements (IDAPA 58.01.01.314.09).

IDAPA 58.01.01.362 requires that as part of its review of the Tier I application, DEQ shall prepare a technical memorandum (i.e., statement of basis) that sets forth the legal and factual basis for the draft Tier I operating permit terms and conditions including reference to the applicable statutory provisions or the draft denial. This document provides the basis for the draft Tier I operating permit for Idaho Power Co. – Bennett Mountain.

The format of this Statement of Basis follows that of the permit. Idaho Power Co. – Bennett Mountain Tier I operating permit is organized into sections. They are as follows:

Section 1 – Acronyms, Units, and Chemical Nomenclature

The acronyms, units, and chemical nomenclature used in the permit are defined in this section.

Section 2 - Tier I Operating Permit Scope

The scope describes this permitting action.

Section 3 - Facility-wide Conditions

The Facility-wide Conditions section contains the applicable requirements (permit conditions) that apply facility-wide. Where required, monitoring, recordkeeping and reporting requirements (MRRR) sufficient to assure compliance with a permit condition follows the permit condition.

Sections 4 through 6 - Combustion Turbine, Fuel Heater, and Emergency Diesel Generator

The emissions unit-specific sections of the permit contain the applicable requirements that specifically apply to each regulated emissions unit. Some requirements that apply to an emissions unit (e.g., opacity limits) may be contained in the Facility-wide Conditions Section. As with the facility-wide conditions, monitoring, recordkeeping and reporting requirements (MRRR) sufficient to assure compliance with an applicable requirement follows the applicable requirement.

Section 7 - Insignificant Activities

This section contains a list of units or activities that are insignificant on the basis of size or production rate. Units and activities listed in this section must be listed in the permit application. The regulatory citation for units and activities that are insignificant on the basis of size or production rate is IDAPA 58.01.01.317.01.b.

Section 8 – Title IV Acid Rain Permit

This section contains Title IV acid rain permit and program requirements.

Section 9 - General Provisions

The final section of the permit contains standard terms and conditions that apply to all major facilities subject to IDAPA 58.01.01.300. This section is the same for all Tier I facilities. The General Provisions have been reviewed by EPA and contain all terms and conditions required by IDAPA 58.01.01 et al as well as requirements from other air quality laws, rules and regulations. Each general provision has been paraphrased so it is more easily understood by the general public; however, there is no intent to alter the effect of the requirement. Should there be a discrepancy between a paraphrased general provision in this statement of basis and a rule or permit, the rule or permit shall govern.

3. FACILITY INFORMATION

Facility Description

Bennett Mountain consists of a 170-megawatt natural gas-fired simple cycle combustion turbine and generator, a natural gas-fuel heater, an emergency diesel generator, and emission units that are insignificant that are listed in that section of the permit. The turbine is primarily operated to generate electric power to meet peak system load requirements.

Facility Permitting History

<u>Tier I Operating Permit History – Current 5-year permit term January 14, 2022 to January 14, 2027</u>

The following information is the permitting history of this Tier I facility for the current five-year permit term which is from January 14, 2022 to January 14, 2027. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

January 14, 2022 T1-2021.0037, Tier I renewal, Permit status (S)

November 10, 2022	T1-2021.0037, Tier I administrative amendment to incorporate PTC No. P-2022.0005, issued July 14, 2022, Permit status (A, will be S upon issuance of this permit)

Tier I Operating Permit History - Previous 5-year permit term February 24, 2017 to January 14, 2022

The following information is the permitting history of this Tier I facility during the previous five-year permit term which was from February 24, 2017 to January 14, 2022. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

February 24, 2017	T1-2016.0039, Tier I renewal, Permit status (S)

Underlying Permit History - Includes every underlying permit issued to this facility

The following information is the comprehensive permitting history of all underlying applicable permits issued to this Tier I facility. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

May 26, 2023	P-2022.0005, updating the fuel sulfur content and modifying the PTE representation of the combustion turbine using updated calculation methodologies and the facility information, consequently, increasing the emissions limits in the permit, Permit status (A)
July 14, 2022	P-2022.0005, allowing for maintenance and upgrades to the function of the turbine, Permit status (S)
December 29, 2008	PROJ 0196, Exemption for 350 kW emergency diesel generator, Permit status (A)
June 21, 2005	P-050002, Revised PTC P-030060 to transfer ownership and update NSPS Subpart GG requirements, Permit status (S)
March 19, 2004	P-030060, Revised PTC P-039-00025, Permit status (S)
September 9, 2002	P-039-00025, Initial PTC for 170 MW natural gas-fired power plant, Permit status (S)

4. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

Application Scope

This permitting action is an administrative amendment to the current Tier I operating permit issued on November 10, 2022. This permitting action incorporates the underlying PTC issued on May 26, 2023.

Application Chronology

October 6, 2023	DEQ received an application to incorporate the underlying PTC into the current Tier I operating permit.
October 23, 2023	DEQ made available the draft permit and statement of basis for applicant review.
November 5, 2023	DEQ issued the final permit and statement of basis

5. EMISSIONS UNITS, PROCESS DESCRIPTION(S), AND EMISSIONS INVENTORY

This section lists the emissions units, describes the production or manufacturing processes, and provides the emissions inventory for this facility. The information presented was provided by the applicant in its permit application. Also listed in this section are the insignificant activities based on size or production rate.

Process No. 1 - Combustion Turbine

Table 5.1 lists the emissions units and control devices associated with the Combustion Turbine.

Table 5.1 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
Combustion Turbine with Generator (CT1) Manufacturer: Siemens-Westinghouse Model: W501F simple-cycle combustion Burner type: Ultra-low NOx burners Heat input rating: 2,143 MMBtu/hr HHV (used for short-term maximum PTE calculations at 100% load at 0 ºF) and 1,960 MMBtu/hr HHV (used for annual PTE calculations at 100% load at 59°F). Nominal generating capacity: 170 MW Fuel: natural gas Date of construction: 2003 Date of modification: July 2022 or later	None

Unit CT1 is a natural gas-fired Siemens-Westinghouse W501F simple-cycle combustion turbine (with generator). This unit has a nominal generating capacity of 170 MW. The heat input is approximately 2,143 MMBtu/hr (higher heating value). This unit is equipped with ultra-low NO_x burners in order to combust a leaner mixture of fuel and air, thereby lowering the peak firing temperature and Nitrogen Oxide (NO_x) emissions.

In the combustion turbine process, ambient air is drawn through an inlet, and then is filtered and compressed. This compressed air is combined with fuel and combusted within the turbine combustion chamber. At Bennett Mountain, the fuel (pipeline natural gas) is pre-heated by the nominal 3.6 MMBtu/hr natural gas fuel heater (H1) prior to combustion.

Exhaust gas from the combustion process is expelled through a power turbine, driving a shaft. The mechanical work produced by the spinning shaft drives an air compressor and an electric power generator. Thus, electric power is produced directly by the mechanical work that spins the turbine shaft.

Process No. 2 – Fuel Heater

Table 5.2 lists the emissions units and control devices associated with the Fuel Heater.

Table 5.2 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
Fuel Heater (H1)	None

At Bennett Mountain, the fuel (pipeline natural gas) is pre-heated by the nominal 3.6 MMBtu/hr natural gas fuel heater (H1) prior to combustion.

Process No. 3 - Emergency Diesel Generator

Table 5.3 lists the emissions units and control devices associated with the emergency diesel generator.

Table 5.3 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
Emergency Diesel Generator (EG1)	None

The emergency diesel generator EG1 is a Cummins 755 brake horsepower generator set. The 350 kilowatt (kW) engine is turbocharged with air-to-air charge air cooling. The guaranteed emission levels are compliant with the levels specified in 40 CFR 89.112, and the manufacturer has verified compliance with U.S.EPA and California emissions regulations under provisions of 40 CFR 89, Non-Road Tier 2 emissions limits. The guaranteed rates and compliance statement are included in the application for the

Tier I renewal, issued January 14, 2022. This generator will be used for emergency operation whenever station power is interrupted. Subpart IIII allows for 100 hours of annual operation for maintenance and readiness. It also allows for unlimited operation during emergency situations. However, the Permit to Construct Exemption No. X-2008.0196 and potential to emit emissions presented in the application are based on a total of 500 hours of operation per year for the emergency diesel generator.

Insignificant Emissions Units Based on Size or Production Rate

This section contains a list of units or activities that are insignificant on the basis of size or production rate. Units and activities listed in this section must be listed in the permit application. Table 5.4 lists the units and activities which have been determined to be insignificant on the basis of size or production rate. The regulatory authority for emissions units and activities that are insignificant on the basis of size or production rate is IDAPA 58.01.01.317.01.b.

Table 5.4 INSIGNIFICANT EMISSION UNITS AND REGULATORY AUTHORITY/JUSTIFICATION

Emissions Unit / Activity	Regulatory Authority / Justification
Operation, loading and unloading of volatile organic compound storage tanks, ten thousand (10,000) gallons capacity or less, with lids or other appropriate closure, vapor pressure not greater than eighty (80) mm Hg at twenty-one (21) degrees C.	IDAPA 58.01.01.317.01.b.i(3)
Operation, loading and unloading of gasoline storage tanks, ten thousand (10,000) gallons capacity or less, with lids or other appropriate closure.	IDAPA 58.01.01.317.01.b.i(3)
Welding using not more than one (1) ton per day of welding rod.	IDAPA 58.01.01.317.01.b.i(9)
Surface coating, using less than two (2) gallons per day.	IDAPA 58.01.01.317.01.b.i(17)
Cleaning and stripping activities and equipment, using solutions having less than one percent (1%) volatile organic compounds by weight.	IDAPA 58.01.01.317.01.b.i(26)

Emissions Inventory

Table 5.5 summarizes the emissions inventory for this major facility. All values are expressed in units of tons-per-year and represent the facility's potential to emit. Potential to emit is defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hour of operation or on the type or amount of material combusted, stored or processed shall be treated as part of its design if the limitation or the effect it would have on emission is state or federally enforceable.

The PTE in Table 5.5 is taken from the underlying PTC No. P-2022.0005, issued May 26, 2023. Refer to the SOB for the underlying PTC for details.

Table 5.5 EMISSIONS INVENTORY - POTENTIAL TO EMIT (T/yr)

Source Description	$PM_{10}/PM_{2.5}$ T/yr	NO_x T/yr	SO_2 T/yr	CO T/yr	VOC T/yr	HAP T/yr
Turbine	61.94	242.16	122.54	243.21	36.05	8.80
Fuel Heater	0.08	1.04	0.123	0.88	0.05	0.02
Emergency diesel generator	0.01	0.40	0.0005	0.22	0.03	<0.01
Total Emissions	**62.03**	**245.00**	**122.66**	**245.00**	**36.12**	**8.82**

6. EMISSIONS LIMITS AND MRRR

This section contains the applicable requirements for this T1 facility.

This section is divided into the following subsections.

- Facility-Wide Conditions;
- Emissions Unit No. 1 – Combustion Turbine Emissions Limits;
- Emissions Unit No. 2 – Fuel Heater Emissions Limits;
- Emissions Unit No. 3 – Diesel Generator Engine Emissions Limits;
- Tier I Operating Permit General Provisions.

MRRR

Monitoring, recordkeeping and reporting requirements (MRRR) are the means with which compliance with an applicable requirement is demonstrated. In this section, the applicable requirement (permit condition) is provided first followed by the MRRR. Should an applicable requirement not include sufficient MRRR to satisfy IDAPA 58.01.01.322.06, 07, and 08, then the permit must establish adequate monitoring, recordkeeping and reporting sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit (i.e., gap filling). In addition to the specific MRRR provided for each applicable requirement, generally applicable facility-wide conditions and general provisions may also be provided, such as performance testing, reporting, and certification requirements.

The legal and factual basis for each permit condition is provided for in this document. If a permit condition was changed due to facility draft comments or public comments, an explanation of the changes is provided.

State Enforceability

An applicable requirement that is not required by the federal CAA and has not been approved by EPA as a SIP-approved requirement is identified as a "State-only" requirement and is enforceable only under state law. State-only requirements are not enforceable by the EPA or citizens under the CAA. State-only requirements are identified in the permit within the citation of the legal authority for the permit condition.

Federal Enforceability

Unless identified as "State-only," all applicable requirements, including MRRR, are state and federally enforceable. It should be noted that while a violation of a MRRR is a violation of the permit, it is not necessarily a violation of the underlying applicable requirement (e.g., emissions limit).

To minimize the length of this document, the following permit conditions and MRRR have been paraphrased. Refer to the permit for the complete requirements.

6.1 Facility-Wide Conditions

To follow the current template, the IDAPA dates in the citations are removed.

Permit Condition 3.1 - Fugitive Dust

All reasonable precautions shall be taken to prevent PM from becoming airborne in accordance with IDAPA 58.01.01.650-651.

[IDAPA 58.01.01.650-651]

MRRR (Permit Conditions 3.2 through 3.4)

- Monitor and maintain records of the frequency and the methods used to control fugitive dust emissions;
- Maintain records of all fugitive dust complaints received and the corrective action taken in response to the complaint; and

- Conduct facility-wide inspections of all sources of fugitive emissions. If any of the sources of fugitive dust are not being reasonably controlled, corrective action is required.

[IDAPA 58.01.01.322.06, 07]

Permit Conditions 3.5 and 3.6 - Odors

Odor related requirements have been removed from the permit because the odor requirements have been removed from the Air Rules.

Permit Condition 3.7 - Visible Emissions

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.

[IDAPA 58.01.01.625]

MRRR (Permit Condition 3.8 through 3.9)

- Conduct facility-wide inspections of all emissions units subject to the visible emissions standards (or rely on continuous opacity monitoring);
- If visible emissions are observed, take appropriate corrective action and/or perform a Method 9 opacity test;
- Maintain records of the results of each visible emissions inspection.

[IDAPA 58.01.01.322.06, 07]

Permit Conditions 3.10 through 3.14 - Excess Emissions

The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions. The provisions of IDAPA 58.01.01.130-136 shall govern in the event of conflicts between the excess emissions facility wide conditions and the regulations of IDAPA 58.01.01.130-136.

[IDAPA 58.01.01.130-136]

MRRR (Permit Conditions 3.11 through 3.14)

- Take appropriate action to correct, reduce, and minimize emissions from excess emissions events;
- Prohibit excess emissions during any DEQ Atmospheric Stagnation Advisory or Wood Stove Curtailment Advisory; and
- Notify DEQ of each excess emissions events as soon as possible, including information regarding upset, breakdown, or safety events.
- Submit a report for each excess emissions event to DEQ; and
- Maintain records of each excess emissions event.

[IDAPA 58.01.01.130-136]

Permit Condition 3.15 – Fuel-Burning Equipment PM Standards

The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas, 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid, 0.050 gr/dscf of effluent gas corrected to 8% oxygen by volume for coal, and 0.080 gr/dscf of effluent gas corrected to 8% oxygen by volume for wood products.

[IDAPA 58.01.01.676-677]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.16 - Sulfur Content Limits

The permittee shall not sell, distribute, use, or make available for use any of the following:

- Distillate fuel oil containing more than the following percentages of sulfur:
  - ASTM Grade 1 fuel oil, 0.3% by weight.
  - ASTM Grade 2 fuel oil, 0.5% by weight.
- Coal containing greater than 1.0% sulfur by weight.
- DEQ may approve an exemption from these fuel sulfur content requirements (IDAPA 58.01.01.725.01 725.04) if the permittee demonstrates that, through control measures or other means, SO2 emissions are equal to or less than those resulting from the combustion of fuels complying with these limitations.

[IDAPA 58.01.01.725]

MRRR - (Permit Condition 3.17)

The permittee shall maintain documentation of supplier verification of fuel sulfur content on an as received basis.

[IDAPA 58.01.01.322.06]

Permit Condition 3.18 - Open Burning

The permittee shall comply with the *Rules for Control of Open Burning*, IDAPA 58.01.01.600-623.

[IDAPA 58.01.01.600-623]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.19 - Asbestos

The permittee shall comply with all applicable requirements of 40 CFR 61, Subpart M— "National Emission Standard for Asbestos."

[40 CFR 61, Subpart M]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.20 - Accidental Release Prevention

An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR 68 no later than the latest of the following dates:

- Three years after the date on which a regulated substance present above a threshold quantity is first listed under 40 CFR 68.130.
- The date on which a regulated substance is first present above a threshold quantity in a process.

[40 CFR 68.10 (a)]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.21 - Recycling and Emissions Reductions

The permittee shall comply with applicable standards for recycling and emissions reduction of refrigerants and their substitutes pursuant to 40 CFR 82, Subpart F, Recycling and Emissions Reduction.

[40 CFR 82, Subpart F]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.22 - NSPS General Provisions

This facility is subject to NSPS Subparts GG and IIII, and is therefore required to comply with applicable General Provisions.

[40 CFR 60, Subpart A]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.23 - Monitoring and Recordkeeping

The permittee shall maintain sufficient records to assure compliance with all of the terms and conditions of this operating 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, 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 58.01.01.322.06, 07]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Conditions 3.24 through 3.27 - Performance Testing

If performance testing is required, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test or shorter time period as provided in a permit, order, consent decree, or by DEQ approval. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests such testing not be performed on weekends or state holidays.

All 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, prior to conducting any performance test, the permittee is encouraged to submit in writing to DEQ, at least 30 days in advance, the following for approval:

- The type of method to be used.
- Any extenuating or unusual circumstances regarding the proposed test.

- The proposed schedule for conducting and reporting the test.

[IDAPA 58.01.01.157, 4/11/2015; IDAPA 58.01.01.322.06, 08.a, 09]

MRRR (Permit Conditions 3.25 and 3.27)

The permittee shall submit compliance test report(s) to DEQ following testing.

[IDAPA 58.01.01.157, 4/11/2015; IDAPA 58.01.01.322.06, 08.a, 09]

Permit Condition 3.28 - Reports and Certifications

This permit condition establishes generally applicable MRRR for submittal of reports, certifications, and notifications to DEQ and/or EPA as specified.

[IDAPA 58.01.01.322.08, 11]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.29 - Incorporation of Federal Requirements by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein.

[IDAPA 58.01.01.107]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Emissions Unit-Specific Emissions Limits and MRRR

6.2 Emissions Unit No. 1 – Combustion Turbine

40 CFR 60 Subpart GG requirements are removed from this section as the modified turbine is no longer subject to the subpart. It is now subject to 40 CFR 60 Subpart KKKK. The new NSPS requirements are added to the Tier I operating permit.

Permit Condition 4.1 – Emissions Limits

The emission limits are taken from the underlying PTC, issued May 26, 2023. They are applicable requirements of the Tier I according to IDAPA58.01.01.008.03.

MRRR – (Permit Conditions 4.3, 4.4 - 4.15)

For $PM_{2.5}/PM_{10}$ and VOC emissions limits, Permit Condition 4.7 requires the applicant to monitor hourly fuel usage of the turbine. No additional monitoring is required as it is inherently limit by the size and design of the turbine.

For SO_2 emissions limits, in addition to the fuel usage monitoring in PC4.7, Permit Condition 4.3 requires the applicant to use natural gas with the sulfur content specified in PC4.3. Permit Condition 4.10 requires the applicant to keep records of the fuel sulfur content and keep it for a minimum of five years.

NOx and CO annual emissions limits are for keeping the facility as a PSD synthetic minor source. To ensure that the facility does not exceed the emissions limits, the permittee is required to operate NO_x and CO CEMS and quantify the volumetric flowrate from the turbine stack, to continually monitor the NO_x and CO emissions actually emitted from the turbine. These requirements appear as Permit Conditions 4.4 through 4.6 in the Tier I permit. Although the NO_x CEMS is also required under the Acid Rain Program, it is utilized as part of the compliance demonstration for the annual NO_x and CO emissions rate limits. Permit Conditions 4.4 through 4.6 ensure that emissions rates of NO_x and CO from the turbine are directly monitored for compliance with the emissions rate limits in Permit Condition 4.1 and also serve to make the emissions rate limits federally enforceable.

Old Permit Condition 4.2 – Fuel Burning Equipment PM Standard

Old PC 4.2 in the Tier I issued January 14, 2022, was removed and replaced with "reserved" during the previous permitting action. The requirement was included in the underlying PTC by mistake as the turbine was not fuel burning equipment as defined in IDAPA 58.01.01.006. The requirement has been removed from the underlying PTC issued May 26, 2023. More discussions can be found in DEQ's guidance on this topic. (2008AAF250)

Permit Condition 4.4 – NO_x CEMS Requirement

As previously discussed, the permittee is required to operate a NO_x CEMS under the Acid Rain Program. This facility is also required to operate a NO_x CEMS in order to demonstrate compliance with the annual facility-wide NO_x emissions limit of 245.0 T/yr.

MRRR – (Permit Conditions 4.8, 4.11-4.15)

Monitoring requirements relative to the Acid Rain Program requirements for the NO_x CEMS appear in Permit Condition 4.8 of the Tier I permit, and additional monitoring requirements for the NO_x CEMS appear in Permit Condition 4.11.

Several specific reporting requirements from the Acid Rain Program and/or from PTC No. P-2022.0005 are contained as Permit Conditions 4.12 through 4.15 of the Tier I operating permit.

Permit Condition 4.5 – CO CEMS Requirement

As previously discussed, the permittee must operate a CO CEMS to demonstrate compliance with the annual facility-wide CO emissions limit of 245.0 T/yr.

MRRR – (Permit Conditions 4.9, 4.11 - 4.14)

Monitoring requirements for the CO CEMS appear in Permit Conditions 4.9 and 4.11 of the Tier I permit. Several specific reporting requirements from PTC No. P-2022.0005 also appear in the Tier I permit as Permit Conditions 4.12 through 4.14.

Because the Combustion Turbine is operated on an intermittent and infrequent basis to meet peak electrical loads, Idaho Power has requested reduced RATA and CGA testing frequencies during any calendar quarter in which the unit is operated less than 168 unit operating hours. DEQ has approved the frequency and span requests consistent with relevant EPA guidance, and to avoid starting the unit only for the purposes of testing. These approvals have been included in Permit Condition 4.9.

Permit Conditions 4.16 and 4.17 – NOx and SO_2 emissions limits in 40 CFR 60, Subpart KKKK

The modified turbine is now subject to NOx and SO_2 emissions limits in 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines.

MRRR – (Permit Conditions 4.18- 4.27)

The MRRR for the emissions limits are specified in the subpart. They appear in PC 4.18 through 4.27 of the Tier I permit.

6.3 Emissions Unit No. 2 – Fuel Heater

Permit Condition 5.1 – Emissions Limits

The emission limits are taken from the underlying PTC issued May 26, 2023. They are applicable requirements of Tier I according to IDAPA 58.01.01.008.03.

MRRR – (Permit Conditions 5.4 and 5.5)

For compliance assessment purposes, the emissions limits in Permit Condition 5.1 will not be exceeded so long as the permittee complies with the volumetric gas combustion limits established in Permit

Condition 5.4 of the Tier I permit. Consequently, the monitoring provisions for Permit Condition 5.5 also serve as the monitoring provision for Permit Condition 5.1.

Permit Condition 5.2 – PM Emissions Limit

The PM emissions limit established by IDAPA 58.01.01.676 (i.e., the fuel-burning equipment standard) is taken from the underlying PTC issued on May 26, 2023. It is an applicable requirement for the Tier I according to IDAPA 58.01.01.008.03.

MRRR – (Permit Condition 5.3)

The fuel heater is only allowed to combust natural gas (refer to Permit Condition 5.3). By using an AP–42 PM emissions factor for natural gas combustion, the volume of flue gas created from combustion of one million British thermal units of natural gas, the heat content of natural gas, and elevation corrections, it can be shown that combustion of natural gas will not exceed the grain-loading standard. Consequently, since this source is not reasonably expected to exceed the applicable standard, no further demonstration of compliance is required in the permit (i.e., monitoring requirements have not been included in the permit).

Permit Condition 5.3 – Fuel Restrictions

Permit Condition 3.5 of PTC No. P-2022.0005 issued May 26, 2023, restricts the heater fuel to natural gas with a sulfur content of 0.05 gr/dscf or less, being the same as that for the turbine in PC2.5 of the PTC issued May 26, 2023. Fuel sulfur content in Permit Condition 5.3 of the Tier I permit is updated.

MRRR – (Permit Condition 4.10)

Permit Condition 4.10 of the Tier I permit requires the permittee to comply with the fuel sulfur and nitrogen monitoring provisions of 40 CFR Part 75, Appendix D, for the combustion turbine.

The combustion turbine operates on natural gas directly from the Williams Northwest pipeline, whereas the fuel heater operates on natural gas from a separate supply from Intermountain Gas Company. Intermountain Gas Company's gas is supplied from the Williams Northwest pipeline, and therefore, should have the same quality, so these monitoring requirements also serve to monitor the fuel combusted within the fuel heater. The monitoring is sufficient for both units.

Permit Condition 5.4 – Fuel Combustion Rate Restriction

Permit Condition 3.6 of PTC No. P-2022.005 issued May 26, 2023, restricts volume of natural gas combusted in the fuel heater to 16,878,613 cubic feet in any consecutive 12-month period. This permit condition appears as Permit Condition 5.4 in the Tier I permit.

MRRR – (Permit Condition 5.5)

The fuel firing restriction serves to make the annual emissions limits for NO_x and CO (refer to Permit Condition 5.1 of the Tier I permit) federally enforceable.

6.4 Emissions Unit No. 3 – Emergency Diesel Generator

The generator was issued an exemption from the requirement to obtain a permit to construct, No. X-2008.0196, on December 29, 2008.

Permit Condition 6.1.1 – Emissions Limits

The emission limits are in the underlying PTC issued May 26, 2023. They are applicable requirements of the Tier I according to IDAPA58.01.01.008.03.

MRRR – (Permit Condition 6.2 - 6.7)

No additional MRRR is needed as long as the applicant complies with the requirements of 40 CFR 60 Subpart IIII.

Permit Condition 6.1.2 through 6.5 – 40 CFR 60 Subpart IIII

This permitting action does not change the NSPS requirements for the emergency generator and does not change the following analyses taken from the SOB for Tier I renewal issued 1/14/2022:

The permittee is required to comply with the management practice requirements for new nonroad compression ignition (CI) engines for the emergency generator, in accordance with 40 CFR 60 Subpart IIII.

The permittee is required to comply with general requirements, such as operating each engine in a manner consistent with safety and good air pollution control practices for minimizing emissions.

The permittee is required to install a non-resettable hour meter.

The permittee is required to continuously comply with the management practice requirements.

MRRR – (Permit Conditions 6.6, 6.7, and 3.23)

40 CFR 60 Subpart IIII has specified MRRR for all the operating and management practice requirements.

6.5 General Provisions

Unless expressly stated, there are no MRRR for the general provisions.

General Compliance, Duty to Comply

The permittee must comply with the terms and conditions of the permit.

[IDAPA 58.01.01.322.15.a; 40 CFR 70.6(a)(6)(i)]

General Compliance, Need to Halt or Reduce Activity Not a Defense

The permittee cannot use the fact that it would have been necessary to halt or reduce an activity as a defense in an enforcement action.

[IDAPA 58.01.01.322.15.b; 40 CFR 70.6(a)(6)(ii)]

General Compliance, Duty to Supplement or Correct Application

The permittee must promptly submit such supplementary facts or corrected information upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application. The permittee must also provide information as necessary to address any new requirements that become applicable after the date a complete application has been filed, but prior to the release of a draft permit.

[IDAPA 58.01.01.315.01; 40 CFR 70.5(b)]

Reopening, Additional Requirements, Material Mistakes, Etc.

This term lists the instances when the permit must be reopened and revised, including times when additional requirements become applicable, when the permit contains mistakes, or when revision or revocation is necessary to assure compliance with applicable requirements.

[IDAPA 58.01.01.322.15.c; IDAPA 58.01.01.386; 40 CFR 70.7(f)(1), (2); 40 CFR 70.6(a)(6)(iii)]

Reopening, Permitting Actions

This term discusses modification, revocation, reopening, and/or reissuance of the permit for cause. If the permittee files a request to modify, revoke, reissue, or terminate the permit, the request does not stay any permit condition, nor does notification of planned changes or anticipated noncompliance.

[IDAPA 58.01.01.322.15.d; 40 CFR 70.6(a)(6)(iii)]

Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

[IDAPA 58.01.01.322.15.e; 40 CFR 70.6(a)(6)(iv)]

Information Requests

The permittee must furnish, within a reasonable time to DEQ, any information, including records required by the permit, that is requested in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit.

[Idaho Code §39-108; IDAPA 58.01.01.122; IDAPA 58.01.01.322.15.f; 40 CFR 70.6(a)(6)(v)]

Information Requests, Confidential Business Information

Upon request, the permittee must furnish to DEQ copies of records required to be kept by this permit. For information claimed to be confidential, the permittee may furnish such records along with a claim of confidentiality in accordance with Idaho Code §9-342A and applicable implementing regulations including IDAPA 58.01.01.128.

[IDAPA 58.01.01.322.15.g; IDAPA 58.01.01.128; 40 CFR 70.6(a)(6)(v)]

Severability

If any provision of the permit is held to be invalid, all unaffected provisions of the permit will remain in effect and enforceable.

[IDAPA 58.01.01.322.15.h; 40 CFR 70.6(a)(5)]

Changes Requiring Permit Revision or Notice

The permittee may not commence construction or modification of any stationary source, facility, major facility, or major modification without first obtaining all necessary permits to construct or an approval under IDAPA 58.01.01.213 or complying with IDAPA 58.01.01.220 through 223. The permittee must comply with IDAPA 58.01.01.380 through 386 as applicable.

[IDAPA 58.01.01.200-223; IDAPA 58.01.01.322.15.i; IDAPA 58.01.01.380-386; 40 CFR 70.4(b)(12), (14), (15), and 70.7(d), (e)]

Changes that are not addressed or prohibited by the Tier I operating permit require a Tier I operating permit revision if such changes are subject to any requirement under Title IV of the CAA, 42 U.S.C. Section 7651 through 7651c, or are modifications under Title I of the CAA, 42 U.S.C. Section 7401 through 7515. Administrative amendments (IDAPA 58.01.01.381), minor permit modifications (IDAPA 58.01.01. 383), and significant permit modifications (IDAPA 58.01.01.382) require a revision to the Tier I operating permit. IDAPA 58.01.01.502(b)(10) changes are authorized in accordance with IDAPA 58.01.01.384. Off permit changes and required notice are authorized in accordance with IDAPA 58.01.01.385.

[IDAPA 58.01.01.381-385; IDAPA 58.01.01.209.05; 40 CFR 70.4(b)(14) and (15)]

Federal and State Enforceability

All permit conditions are federally enforceable unless specified in the permit as a state or local only requirement. State and local only requirements are not required under the CAA and are not enforceable by EPA or by citizens.

[IDAPA 58.01.01.322.15.j; IDAPA 58.01.01.322.15.k; Idaho Code §39-108; 40 CFR 70.6(b)(1), (2)]

Inspection and Entry

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

- Enter upon the permittee's premises where a Tier I source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- 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; IDAPA 58.01.01.322.15.l; 40 CFR 70.6(c)(2)]

New Applicable Requirements

The permittee must continue to comply with all applicable requirements and must comply with new requirements on a timely basis.

[IDAPA 58.01.01.322.10; IDAPA 58.01.01.314.10.a.ii; 40 CFR 70.6(c)(3) citing 70.5(c)(8)]

Fees

The owner or operator of a Tier I source shall pay annual registration fees to DEQ in accordance with IDAPA 58.01.01.387 through IDAPA 58.01.01.397.

[IDAPA 58.01.01.387; 40 CFR 70.6(a)(7)]

Certification

All documents submitted to DEQ shall be certified in accordance with IDAPA 58.01.01.123 and comply with IDAPA 58.01.01.124.

[IDAPA 58.01.01.322.15.o; 40 CFR 70.6(a)(3)(iii)(A); 40 CFR 70.5(d)]

Renewal

The permittee shall submit an application to DEQ for a renewal of this permit at least six months before, but no earlier than 18 months before, the expiration date of this operating permit. To ensure that the term of the operating permit does not expire before the permit is renewed, the owner or operator is encouraged to submit a renewal application nine months prior to the date of expiration.

[IDAPA 58.01.01.313.03; 40 CFR 70.5(a)(1)(iii)]

If a timely and complete application for a Tier I operating permit renewal is submitted, but DEQ fails to issue or deny the renewal permit before the end of the term of this permit, then all the terms and conditions of this permit including any permit shield that may have been granted pursuant to IDAPA 58.01.01.325 shall remain in effect until the renewal permit has been issued or denied.

[IDAPA 58.01.01.322.15.p; 40 CFR 70.7(b)]

Permit Shield

Compliance with the terms and conditions of the Tier I operating permit, including those applicable to all alternative operating scenarios and trading scenarios, shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that:

- Such applicable requirements are included and are specifically identified in the Tier I operating permit; or
    - DEQ has determined that other requirements specifically identified are not applicable and all of the criteria set forth in IDAPA 58.01.01.325.01(b) have been met.
- The permit shield shall apply to permit revisions made in accordance with IDAPA 58.01.01.381.04 (administrative amendments incorporating the terms of a permit to construct), IDAPA 58.01.01.382.04 (significant modifications), and IDAPA 58.01.01.384.03 (trading under an emissions cap).
- Nothing in this permit shall alter or affect the following:
    - Any administrative authority or judicial remedy available to prevent or terminate emergencies or imminent and substantial dangers;
    - The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;
    - The applicable requirements of the acid rain program, consistent with 42 U.S.C. Section 7651(g)(a); and

- The ability of EPA to obtain information from a source pursuant to Section 114 of the CAA; or the ability of DEQ to obtain information from a source pursuant to Idaho Code §39-108 and IDAPA 58.01.01.122.

[Idaho Code §39-108 and 112; IDAPA 58.01.01.122; IDAPA 58.01.01.322.15.m, 325.01; IDAPA 58.01.01.325.02; IDAPA 58.01.01.381.04, 382.04, 383.05, 384.03, 385.03; 40 CFR 70.6(f)]

Compliance Schedule and Progress Reports

- For each applicable requirement for which the source is not in compliance, the permittee shall comply with the compliance schedule incorporated in this permit.
- For each applicable requirement that will become effective during the term of this permit and that provides a detailed compliance schedule, the permittee shall comply with such requirements in accordance with the detailed schedule.
- For each applicable requirement that will become effective during the term of this permit that does not contain a more detailed schedule, the permittee shall meet such requirements on a timely basis.
- For each applicable requirement with which the permittee is in compliance, the permittee shall continue to comply with such requirements.

[IDAPA 58.01.01.322.10; IDAPA 58.01.01.314.9; IDAPA 58.01.01.314.10; 40 CFR 70.6(c)(3) and (4)]

Periodic Compliance Certification

The permittee shall submit compliance certifications during the term of the permit for each emissions unit to DEQ and the EPA, as specified.

- Compliance certifications for all emissions units shall be submitted annually, unless otherwise specified; and
- All original compliance certifications shall be submitted to DEQ and a copy of all compliance certifications shall be submitted to the EPA.

[IDAPA 58.01.01.322.11; 40 CFR 70.6(c)(5)(iii) as amended, 62 Fed. Reg. 54900, 54946 (10/22/1997); 40 CFR 70.6(c)(5)(iv)]

False Statements

The permittee may not 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]

No Tampering

The permittee may not 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]

Semiannual Monitoring Reports.

In addition to all applicable reporting requirements identified in this permit, the permittee shall submit reports of any required monitoring at least every six months as specified.

[IDAPA 58.01.01.322.15.q; IDAPA 58.01.01.322.08.c; 40 CFR 70.6(a)(3)(iii)]

Reporting Deviations and Excess Emissions

Each and every applicable requirement, including MRRR, is subject to prompt deviation reporting. Deviations due to excess emissions must be reported in accordance with Sections 130-136. All instances of deviation from Tier I operating permit requirements must be included in the deviation reports. The reports must describe the probable cause of the deviation and any corrective action or preventative measures taken. Deviation reports must be submitted at least every six months, unless the permit specifies a different time period as required by IDAPA 58.01.01.322.08.c. Examples of deviations include, but are not limited to, the following:

- Any situation in which an emissions unit fails to meet a permit term or condition.
- Emission control device does not meet a required operating condition.
- Observations or collected data that demonstrate noncompliance with an emissions standard.
- Failure to comply with a permit term that requires a report.

[IDAPA 58.01.01.322.15.q; IDAPA 58.01.01.135; 40 CFR 70.6(a)(3)(iii)]

Permit Revision Not Required, Emissions Trading

No permit revision will be required, under any approved, economic incentives, marketable permits, emissions trading, and other similar programs or processes, for changes that are provided for in the permit.

[IDAPA 58.01.01.322.05.b; 40 CFR 70.6(a)(8)]

Emergency

In accordance with IDAPA 58.01.01.332, an "emergency" as defined in IDAPA 58.01.01.008, constitutes an affirmative defense to an action brought for noncompliance with such technology-based emissions limitation if the conditions of IDAPA 58.01.01.332.02 are met.

[IDAPA 58.01.01.332.01; 40 CFR 70.6(g)]

7. REGULATORY REVIEW

Attainment Designation (40 CFR 81.313)

The facility is located in Elmore County, which is designated as attainment or unclassifiable for PM_{10}, $PM_{2.5}$, CO, NO_2, SO_X, and Ozone. Reference 40 CFR 81.313.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

This facility is a Title V source because the emissions exceed the Title V major source threshold for NO_x and CO.

PSD Classification (40 CFR 52.21)

This facility's potential emissions are below PSD major source thresholds for all criteria pollutants. Therefore, the facility is not a PSD major source.

NSPS Applicability (40 CFR 60)

<u>Subpart GG (non-applicable)</u>

The turbine is modified in the summer of 2022 and is now subject to 40 CFR 60 Subpart KKKK. As a result of the turbine modification, the turbine is no longer subject to 40 CFR 60 Subpart GG.

<u>Subpart KKKK</u>

The turbine is modified in the summer of 2022 and is now subject to 40 CFR 60 Subpart KKKK. Detailed regulatory analysis can be found in Appendix A of the SOB.

<u>Subpart IIII</u> - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

No change is made to the following analysis that is taken from the SOB for the Tier I renewal issued on 1/14/2022:

The emergency diesel generator EG1 is a Cummins 755 brake horsepower generator set. The 350 kilowatt (kW) engine is turbocharged with air-to-air charge air cooling. The guaranteed emission levels are compliant with the levels specified in 40 CFR 89.112, and the manufacturer has verified compliance with

U.S.EPA and California emissions regulations under provisions of 40 CFR 89, Non-Road Tier 2 emissions limits. This generator will be used for emergency operation whenever station power is interrupted. The generator was manufactured in 2007. The operating hours are logged from a non-resettable hour meter. The engine displacement is 2.48 liters per cylinder.

§ 60.4200 *(a) The provisions of this subpart are applicable to … owners … of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.*

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

This rule applies to the emergency generator because it was constructed after July 11, 2005.

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

This engine is certified. No testing is required in accordance with Table 8 of this regulation.

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

The engine is certified, and no testing is required to demonstrate compliance.

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

This applies and a permit condition was written.

40 FR 80.510(b) is as follows:

Beginning June 1, 2010, Except as otherwise specifically provided in this subpart, all NR and LM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content.

(i) 15 ppm maximum for NR diesel fuel.

(ii) 500 ppm maximum for LM diesel fuel.

(2) Cetane index or aromatic content, as follows:

(i) A minimum cetane index of 40; or

(ii) A maximum aromatic content of 35 volume percent.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

The generator has a non-resettable hour meter.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

These requirements were incorporated into the permit.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b) ... you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

No testing is required for certified engines.

(f) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

This was incorporated into the permit.

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

This applies, but was not incorporated into the permit because these modifications were not proposed by the applicant in the application.

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

No testing is required because this is a certified engine.

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

This section does not apply because the rating on the generator is greater than 175 HP and was installed prior to 2011. According to Table 5, this section of the rule does not apply.

NESHAP Applicability (40 CFR 61)

No NESHAP applies to this facility.

MACT Applicability (40 CFR 63)

No change is made to the following analysis that is taken from the SOB for the Tier I renewal issued on 1/14/2022:

<u>Subpart YYYY</u>

The requirements of 40 CFR 63, Subpart YYYY National Emission Standards for Hazardous Air Pollutants for Stationary Combustions Turbines, do not apply to the combustion turbine, because this facility is not a major source of HAP emissions. Only new, existing, or reconstructed stationary combustion turbines located at a major source of HAP emissions are subject to the requirements contained in Subpart YYYY.

<u>Subpart ZZZZ</u>

This subpart applies, but the requirements are met by complying with Subpart IIII, in accordance with 40 CFR 63.6590(c):

Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

Also:

40 CFR 60.6590(a)(2)(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

The generator was built in 2007, so it is a new stationary RICE. It is located at a non-major HAP facility, so it is at an area source of HAPs.

CAM Applicability (40 CFR 64)

The turbine uses a ultra-low NO_x combustor which is not subject to CAM because it does not meet the definition of "control device" at 40 CFR 64.1, as follows: *For purposes of this part, a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of seals, lids, or roofs to prevent the release of pollutants, use of low-polluting fuel or feedstocks, or the use of combustion or other process design features or characteristics.*

Acid Rain Permit (40 CFR 72-75)

This facility is subject to the Acid Rain Program requirements of Parts 72 through 78. The combustion turbine is an affected unit in accordance with 40 CFR 72.6(a)(3)(i) and is therefore subject to the Acid Rain Program. This permitting action does not change any requirements related to Acid Rain Permit.

8. PUBLIC COMMENT

In accordance with IDAPA 58.01.01.58.209.05.c, the Tier I is processed as a Tier I administrative amendment, and a public comment period is not required.

9. EPA REVIEW OF PROPOSED PERMIT

In accordance with IDAPA 58.01.01.58.209.05.c, the Tier I is processed as a Tier I administrative amendment, and EPA 45-day review is not required.

Appendix A – 40 CFR 60 Subpart KKKK

Form FRA Regulatory Review

NSPS Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

The combustion turbine is subject to NSPS Subpart KKKK. The applicable parts are highlighted in yellow below. The below regulatory sections were obtained from www.ecfr.gov on December 10, 2021.

SOURCE: 71 FR 38497, July 6, 2006, unless otherwise noted.

INTRODUCTION

§60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

APPLICABILITY

§60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

The combustion turbine heat input is greater than 10 MMBtu/hr and the current modification is taking place after February 18, 2005 therefore this subpart applies to the combustion turbine.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

The combustion turbines are now exempt from subpart GG requirements.

§60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

EMISSION LIMITS

§60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

The applicable emission limit is 15 ppm at 15 percent O_2, applicable to new, modified, or reconstructed turbines firing natural gas with combustion turbine heat input at peak load (HHV) > 850 MMBtu/hr. The combustion turbine upgrade results in manufacturer specified emissions of 9 ppm NO_x at 15 percent O_2, which is compliant with the 15 ppm limit. 96 ppm at load less than 75%.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§60.4325 is not applicable because the combustion turbine burns only natural gas.

§60.4330 What emission limits must I meet for sulfur dioxide (SO2?)

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

The Facility fires pipeline-quality natural gas and has potential sulfur emissions according to an SO_2 emission factor of 0.00056 lb SO_2/MMBtu for the combustion turbine and duct burners, which is less than 0.060 lb SO_2/MMBtu.

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

GENERAL COMPLIANCE REQUIREMENTS

§60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

Idaho Power will continue to operate the combustion turbine in a manner consistent with good air pollution control practices.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

MONITORING

§60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

The Facility does not use water or steam injection.

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

Continuous emission monitoring (CEMS) operates at the facility and will continue to operate after the Project. It is anticipated that the CEMS requirements in 60.4345 will be incorporated into the updated PTC and Tier I permits.

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

§60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§60.4345 will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4345 requirements.

§60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit ~~or the following equation for units complying with the output based standard:~~

~~(1) For simple-cycle operation:~~

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad (Eq. 1)$$

~~Where:~~

~~E = hourly NOx emission rate, in lb/MWh,~~

~~(NOx)h = hourly NOx emission rate, in lb/MMBtu,~~

~~(HI)h = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D-15a in appendix D to part 75 of this chapter, and~~

~~P = gross energy output of the combustion turbine in MW.~~

~~(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:~~

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (Eq. 2)$$

~~Where:~~

~~P = gross energy output of the stationary combustion turbine system in MW.~~

~~$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,~~

~~$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and~~

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad (Eq. 3)$$

~~Where:~~

~~Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,~~

~~Q = measured steam flow rate in lb/h,~~

~~H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 × 10_6 = conversion from Btu/h to MW.~~

~~Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.~~

~~(3) For mechanical drive applications complying with the output-based standard, use the following equation:~~

$$E = \frac{(NO_X)_m}{BL * AL} \qquad (Eq. 4)$$

~~Where:~~

~~E = NO_X emission rate in lb/MWh,~~

~~$(NO_X)_m$ = NO_X emission rate in lb/h,~~

~~BL = manufacturer's base load rating of turbine, in MW, and~~

~~AL = actual load as a percentage of the base load.~~

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

~~(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).~~

§60.4345 will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4345 requirements.

§60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

~~(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.~~

~~The Facility is subject to part 75 requirements and the current Tier I permit Conditions 4.6, 4.10, 4.12, 4.17 outline NO_X emissions measurement requirements in accordance with part 75. The Facility will continue to comply with the requirements as listed in the current Tier I permit Conditions 4.6, 4.10, 4.12, 4.17 which provides compliance with part 60 §60.4355(b) above.~~

§60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§60.4360 will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4360 requirements.

§60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas ~~and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit.~~ You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§60.4365 will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4365 requirements.

~~§60.4370 How often must I determine the sulfur content of the fuel?~~

~~The frequency of determining the sulfur content of the fuel must be as follows:~~

~~(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).~~

~~(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.~~

~~(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.~~

~~(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:~~

~~(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.~~

~~(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but~~

~~less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.~~

~~(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:~~

~~(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.~~

~~(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.~~

~~(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.~~

~~(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.~~

~~(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:~~

~~(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.~~

~~(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.~~

~~(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.~~

~~(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.~~

Bennett Mountain elects to demonstrate sulfur content using options in 60.4365(b) using fuel sampling specified in section 2.3.1.4 or 2.3.2.4 of Appendix D. I

REPORTING

§60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

~~(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.~~

§60.4375 will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4375 requirements.

§60.4380 How are excess emissions and monitor downtime defined for NOX?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

§60.4380(b) will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4380(b) requirements.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§60.4385 How are excess emissions and monitoring downtime defined for SO2?

~~If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:~~

~~(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.~~

~~(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.~~

~~(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.~~

Bennett Mountain elects to use 60.4365(b) and is therefore exempt from the fuel sulfur monitoring described in §60.4385.

§60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

§60.4395 will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4395 requirements.

PERFORMANCE TESTS

§60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad (Eq. 5)$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

~~(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.~~

~~(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.~~

~~(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_X emission limit.~~

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§60.4400 will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4400 requirements. Note: the applicant has chosen to use NOx CEM and can comply with 60.4405.

§60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

If elect CEM, subsequent annual performance test is not required per the preamble. The Facility will comply with §60.4405 requirements.

~~§60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?~~

~~If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.~~

Does not apply as Bennett elects to use NOx CEM.

§60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are four methodologies that you may use to conduct the performance tests.

(1) The use of a current, valid purchase contract, tariff sheet, or transportation contract for the fuel specifying the maximum total sulfur content of all fuels combusted in the affected facility. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter may be used.

(2) Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see §60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see §60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see §60.17). For manual sampling of liquid fuels, follow GPA 2174 or the procedures for manual pipeline sampling in section 14 of ASTM D4057 (both incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

~~(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, D5453, D5623, or D7039 (all incorporated by reference, see §60.17); or~~

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see §60.17).

(3) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(4) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

<u>§60.4415 will be incorporated into the updated PTC and Tier I permits for the facility. The Facility will comply with §60.4415 requirements.</u>

(b) [Reserved]

[71 FR 38497, July 6, 2006, as amended at 85 FR 63410, Oct. 7, 2020]

DEFINITIONS

§60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)

New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

Appendix B - Facility Comments on Draft Permit

The following comments were received from the facility on the DRAFT permit on October 31, 2023:

Facility Comment:

I don't have any substantial or official comments to the draft Tier I Permit or the draft Tier I SOB.

The only issue I found was the wording around the 170MW nominal capacity. The projected capacity at ISO conditions (nominal) post upgrade was more like 185MW. The reference to 170MW does not tie into any actual permit conditions and it was not used in the emissions calculations. The heat input is more specific because it relates directly to stack exhaust flow and mass emissions. The 170MW is simply part of the project description that could have been updated in the PTC application and underlying PTC permit. I do not have any issue with is saying 170MW because the heat input rates are more specific and they are correct.

DEQ Response: the change is not made as it needs to be done in the underlying PTC first.