Statement of Basis

Permit to Construct No. P-2009.0092
Project ID 63087

Idaho Power Co - Langley Gulch Power Plant
New Plymouth, Idaho

Facility ID 075-00012

Final

November 14, 2023
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Permit Writer

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The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

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ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
ASTM	American Society for Testing and Materials
BAE	baseline actual emissions
BACT	Best Available Control Technology
Btu	British thermal units
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	continuous emission monitoring systems
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 systems
CT	combustion turbine
DAHS	data acquisition and handling system
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
HRSG	heat recovery steam generator
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
lb/hr	pounds per hour
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
MMscf	million standard cubic feet
MW	megawatts
NAAQS	National Ambient Air Quality Standard
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
PAE	projected actual emissions
PC	permit condition
PEI	project emissions increase
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
PTC	permit to construct
PTC/T2	permit to construct and Tier II operating permit
PTE	potential to emit
RMRR	routine maintenance, repair, and replacement
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
SO_x	sulfur oxides
TDS	total dissolved solids
T/yr	tons per consecutive 12 calendar month period
TAP	toxic air pollutants
VOC	volatile organic compounds

FACILITY INFORMATION

Description

The Idaho Power Company – Langley Gulch Power Plant operates as a one-on-one, combined cycle plant consisting of a natural gas-fired combustion turbine and a steam turbine. The combustion turbine is equipped with a heat recovery steam generator (HRSG) which uses exhaust heat to produce steam for the steam turbine. Supplemental natural gas duct firing within the HRSG provides additional heat in the exhaust gases which increases steam production and steam turbine output for peak loads. Ancillary equipment includes a diesel-fired emergency pump house generator engine, a diesel-fired fire pump, a wet cooling tower, and three dry chemical storage silos. Dry chemicals for cooling water treatment may include magnesium oxide, soda ash, and lime.

Permitting History

The following 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 1, 2022	P-2009.0092, PTC revision to increase heat input capacity, replace duct burners, and replace NOx combustors, Permit status (A, but will become S upon issuance of this permit)
July 11, 2018	P-2009.0092, DEQ initiated PTC revision to correct the submittal of performance test reports from 30 to 60 days, Permit status (S)
August 14, 2013	P-2009.0092, PTC revision to correct inconsistencies between the permit and installed equipment and actual facility operations, Permit status (S)
June 25, 2010	P-2009.0092, Initial PTC for a natural gas-fired power plant, Permit status (S)

Application Scope

This PTC is for a modification at an existing Tier I facility. See the current Tier I permit statement of basis for the permitting history.

The applicant has proposed to update the ammonia injection system to using a slip method to determine compliance.

Application Chronology

March 3, 2023	DEQ received an application and an application fee.
April 28, 2023	DEQ determined that the application was complete.
August 31, 2023	DEQ made available the draft permit and statement of basis for peer and regional office review.
September 28, 2023	DEQ made available the draft permit and statement of basis for applicant review.
November 6, 2023	DEQ received the permit processing fee.
November 14, 2023	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source ID No.	Sources	Control Equipment	Emission Point ID No.
1	<u>Combustion Turbine and Duct Burner (CT1):</u> *Combustion Turbine* Manufacturer: Siemens Model: SGT6-5000F Configuration: 1x1 combined cycle Manufacture Date: 2010 Heat input rating: 2,241 MMBtu/hr[(a)] Maximum operation: 7,884 hr/yr Fuel: natural gas Fuel consumption: 793.1 MM lb/yr[(b)] *Duct Burner* Manufacturer: Zecco Manufacture date: January 2022 Heat input rating: 241.28 MMBtu/hr Maximum operation: 7,884 hr/yr Fuel: Natural gas	Ultra-low NO_X burners Selective catalytic reduction Catalytic oxidation system Good combustion practices	HRSG Stack
2	<u>Emergency Engine:</u> Manufacturer: Caterpillar Model: C27 Manufacture date: 2010 Maximum capacity: 1,214 BHP, 2.25 L/cylinder Maximum Operation: 4 hr/day and 60 hr/yr Fuel: ultra-low sulfur diesel Fuel consumption: 53.6 gph	EPA Tier 2 technologies Good combustion practices	Emergency Engine Stack
3	<u>Fire Pump Engine:</u> Manufacturer: Cummins Model: CFP9E-F30 Manufacture date: 2010 Maximum capacity: 305 BHP, 1.48 L/cylinder Maximum operation: 2 hr/day and 40 hr/yr[(c)] Fuel: ultra-low sulfur diesel Fuel consumption: 15.8 gph	EPA Tier 3 technologies Good combustion practices	Fire Pump Engine Stack
4	<u>Cooling Tower:</u> Manufacturer: GEA Model: 7-cell, counterflow wet Manufacture date: 2010 Maximum water flow: 76,151 gpm Maximum TDS: 5,000 mg/L	Drift eliminators Good operating practices	Cooling Tower Stack
5	<u>Dry Chemical Storage Silos (3):</u> Manufacturer: Chemco Systems Manufacture date: 2010 Maximum capacities: 6,500, 2,200, and 2,900 ft^3 Maximum loading operations: 2 hr/day and 48 hr/yr per silo	Bin vent filters Good operating practices	Bin Vent Filter Vents
6	<u>Above Ground Fuel Storage Tanks (2):</u> Manufacture date: 2013 Maximum capacity: 250 gal each (diesel/gasoline)	Lids or other appropriate closure	Fuel Storage Tank Vents

(a) At higher heating value, 100 percent of peak load, and 0 °C
(b) Combined fuel usage limit for the CT and the duct burner
(c) For maintenance and testing activities

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit 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 hours 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 emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit an emission inventory was developed for all criteria pollutants from all emissions units at the facility as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Pre-Project Potential to Emit

The following table presents the pre-project potential to emit for all criteria pollutants from all emissions units at the facility as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 2 PRE-PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source		$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC		CO_2e
		lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	T/yr[(b)]
Combustion Turbine and Duct Burner	Peak	13.11	48.51	3.56	12.46	21.00	87.75	12.78	278.12	7.32	74.88	1,093,807
	Low Load					452.78		70.35		18.91		
	SU/SD					304.56		2510.0		186.60		
Emergency Diesel Engine		0.40	0.01	0.01	0.01	12.80	0.39	7.00	0.21	0.80	0.02	42
Fire Pump Engine		0.40	0.01	0.01	0.01	2.00	0.03	1.70	0.03	0.10	0.00	7
Cooling Tower		0.81	3.50	-	-	-	-	-	-	-	-	-
Dry Chemical Storage Silos (3)		0.13	0.01	-	-	-	-	-	-	-	-	-
Above Ground Fuel Storage Tanks (2)		-	-	-	-	-	-	-	-	0.03	0.15	-
Post Project Totals		**14.85**	**52.04**	**3.58**	**12.48**	**467.58**	**88.17**	**2,518.70**	**278.36**	**187.53**	**75.07**	**1,093,856**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Post Project Potential to Emit

Post project Potential to Emit is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post project Potential to Emit includes all permit limits resulting from this project.

The following table presents the post project Potential to Emit for criteria pollutants from all emissions units at the facility as determined by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 3 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source		$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC		CO_2e
		lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	T/yr[(b)]
Combustion Turbine and Duct Burner	Peak	13.11	48.49	3.56	12.46	21.00	87.75	12.78	278.12	7.32	74.88	1,093,308
	Low Load					452.78		70.35		18.91		
	SU/SD					304.56		2510.0		186.60		
Emergency Diesel Engine 1		0.40	0.01	0.01	0.0004	12.85	0.39	6.96	0.21	0.80	0.02	36
Emergency Engine 2		0.02	0.001	0.01	0.0003	1.87	0.09	3.26	0.16	0.18	0.009	28
Fire Pump Engine		0.10	0.002	0.001	0.00	2.02	0.04	1.75	0.03	0.09	0.002	7
Cooling Tower		0.80	3.50	-	-	-	-	-	-	-	-	-
Dry Chemical Storage Silos (3)		0.13	0.01	-	-	-	-	-	-	-	-	-
Above Ground Fuel Storage Tanks (2)		-	-	-	-	-	-	-	-	0.03	0.15	-
Post Project Totals		**14.56**	**52.02**	**3.58**	**12.46**	**469.51**	**88.27**	**2,521.97**	**278.52**	**187.71**	**75.06**	**1,093,380**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants.

Table 4 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Pre-Project Potential to Emit	14.85	52.04	3.58	12.48	467.58	88.17	2,518.70	278.36	187.53	75.07
Post Project Potential to Emit	14.56	52.02	3.58	12.46	469.51	88.27	2,521.97	278.52	187.71	75.06
Changes in Potential to Emit	**-0.29**	**-0.02**	**0.00**	**-0.02**	**1.93**	**0.10**	**3.27**	**0.16**	**0.18**	**-0.01**

Non-Carcinogenic TAP Emissions

A summary of the estimated PTE for emissions increase of non-carcinogenic toxic air pollutants (TAP) is provided in the following table. Pre- and post-project, as well as the change in, non-carcinogenic TAP emissions are presented in the following table:

Table 5 PRE- AND POST PROJECT POTENTIAL TO EMIT FOR NON-CARCINOGENIC TOXIC AIR POLLUTANTS

Non-Carcinogenic Toxic Air Pollutants	Pre-Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Post Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Non-Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Acrolein	1.43E-02	1.44E-02	0.0001	1.70E-02	No
Ethylbenzene	7.17E-02	7.17E-02	0.0000	2.90E+01	No
Naphthalene	2.91E-03	3.28E-03	0.0004	3.33E+00	No
Propylene Oxide	6.50E-02	6.84E-02	0.0034	3.20E+00	No
Toluene	2.91E-01	2.93E-01	0.0020	2.50E+01	No
Xylene	1.43E-01	1.44E-01	0.0010	2.80E+01	No

All changes in emissions rates for non-carcinogenic TAP were below EL (screening emissions level) as a result of this project. Therefore, modeling is not required for any non-carcinogenic TAP because none of the 24-hour average non-carcinogenic screening ELs identified in IDAPA 58.01.01.585 were exceeded.

Carcinogenic TAP Emissions

The change in annual average emissions of carcinogenic TAPs is required to determine modelling applicability for this project. The facility has not proposed an increase in annual fuel usage for the combustion turbine, therefore no emissions change on an annual average will result for this project. Consequently, the change in annual average emission rates for all carcinogenic TAPs is zero and modelling of carcinogenic TAP emissions is not required.

Post Project HAP Emissions

The following table presents the post project potential to emit for HAP pollutants from all emissions units at the facility as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 6 HAZARDOUS AIR POLLUTANTS EMISSIONS POTENTIAL TO EMIT SUMMARY

Hazardous Air Pollutants	PTE (T/yr)
1,3-Butadiene	3.63E-03
Acetaldehyde	3.37E-01
Acrolein	5.39E-02
Arsenic	1.91E-04
Benzene	1.03E-01
Beryllium	1.15E-05
Cadmium	1.05E-03
Chromium	1.34E-03
Cobalt	8.04E-05
Dichlorobenzene	1.15E-03
Ethylbenzene	2.69E-01
Formaldehyde	6.04E+00
Hexane	1.72E+00
Manganese	3.64E-04
Mercury	2.49E-04
Naphthalene	1.15E-02
Nickel	2.01E-03
Propylene Oxide	2.44E-01
Selenium	1.92E-05
Toluene	2.30E-05
Xylenes	1.10E+00
Totals	**10.42**

Ammonia Slip Calculation

The ammonia emissions from the HRSG stack are limited to 5 ppmvd of gas volume at 15% oxygen (O2) per Tier I permit condition 4.9 and PTC permit condition 3.11. The compliance point is based on a 24-hr rolling average. The HRSG stack emissions are generated from the combustion turbine, duct burners, and SCR system. The SCR is downstream of the combustion turbine and duct burners and converts nitric oxide (NO) and nitrogen dioxide (NO2) in the exhaust stream to molecular nitrogen and oxygen by reacting the NOx with ammonia in the presence of a catalyst. Not all of the ammonia is consumed in the reaction leaving some ammonia present in the exhaust flowing out of the HRSG stack. This unconsumed ammonia is called ammonia slip.

The combustion turbine was upgraded and the duct burners were replaced in Spring of 2022. These modifications were permitted under PTC P-2009.0092 issued February 1, 2022. The recent modifications have reduced the amount of NOx generated by the combustion turbine. This results in a lower demand for NOx reduction from the SCR, and therefore less ammonia needed to supply the SCR. The Tier I permit condition 4.20 and PTC permit condition 3.22 place a static limit of 1.03 gallons per minute of ammonia injection to ensure compliance with the 5 ppmvd stack ammonia limit. This 1.03 gallons per minute limit was developed during the original facility design and permitting and has been the applicable limit under all ambient conditions and all loads.

The upgraded combustion turbine produces less NOx than the original facility design of the combustion turbine, therefore the ammonia flow to the SCR has different operational needs to maintain the HRSG stack ammonia concentration below 5 ppmvd. Idaho Power believes that a static volumetric flow rate limit on ammonia injection is no longer the most technically robust method of demonstrating compliance with the 5 ppmvd ammonia HRSG stack concentration limit for the upgraded turbine, and instead wants to develop a new method of ensuring compliance with the 5 ppmvd ammonia limit that is refined to fit the operational characteristics of the current Langley Gulch facility.

Determination of Ammonia Slip Calculation Method

Idaho Power is proposing a dynamic limit on ammonia injection in lb/hr based on the real-time operating conditions of the turbine, duct burners, and SCR. This dynamic limit would replace the current static 1.03 gallon per minute injection flow for ammonia. Current industry standards for demonstrating compliance with an ammonia slip limit is either to:

- Directly measure ammonia slip at the stack with an analyzer similar to a NOx or CO analyzer; or
- Calculate ammonia slip in the continuous emissions monitoring system (CEMS) using the stack exhaust flow, the NOx concentration at the inlet of the SCR, and the NOx concentration at the stack exhaust outlet. The calculated ammonia slip is verified with periodic stack testing.

Both methods effectively provide a dynamic limit for ammonia injection and directly demonstrate compliance with the 5 ppmvd ammonia slip limit. Idaho Power has reviewed the advantages and disadvantages of both methods and has proposed the ammonia slip calculation method for Langley Gulch. The facility already owns and operates the equipment needed to support the ammonia slip calculation, and has both SCR inlet and outlet NOx CEMS already integrated with the ammonia injection controller and subject to normal quality assurance tests.

The calculated ammonia slip is based on subtracting the ammonia consumed in the SCR reaction from the ammonia injected to find the unused ammonia. The unused ammonia is used to calculate the ammonia concentration in the stack flow at 15% O2. The ammonia consumed in the SCR reaction is based on the difference in NOx readings between the stack and the SCR inlet.

Idaho Power consulted with IDEQ, the CEMS vendor for Langley Gulch, and Trinity Consultants to determine the proposed approach for the calculated ammonia slip at the HRSG stack. The proposed method is based on a stoichiometric calculation of the reaction of ammonia with NOx to form elemental nitrogen and water. California's San Joaquin Valley Air Quality Management District (SJVAQMD) developed an equation to combine the multiple chemical reactions involved with the NOx reduction and relationship between stack exhaust characteristics and inlet ammonia injection rate. The equation has been modified to add a second correction factor (CFNOx) based on feedback from IDEQ. The proposed equation for calculating ammonia slip is Equation 1 as follows:

Equation 1

$$R = \frac{\left(\frac{F_{NH3}}{17} - \left(\frac{\frac{F_{Stack}}{29} \times (A - B + CF_{NOx})}{10^6}\right)\right) \times 10^6}{\frac{F_{Stack}}{29}} \times \left(\frac{20.9 - 15.0}{20.9 - C_{O2}}\right) \times CF_{NH3}$$

Where:

- R = stack ammonia concentration, corrected to 15% O2 [ppm]
- F_{NH3} = ammonia injection rate [lb/hr]
- F_{Stack} = exhaust stack flow [lb/hr]
- A = SCR inlet NOx concentration [ppm]
- B = SCR outlet (i.e. HRSG stack) NOx concentration [ppm]
- C_{O2} = oxygen concentration in stack [% by volume dry]
- CF_{NOx} = correction factor for difference between SCR inlet and outlet NOx CEMS [ppm]
- CF_{NH3} = correction factor for difference between calculated and reference ammonia concentration [ppm]

None of the input variables in Equation 1 (F_{NH3}, F_{Stack}, A, or B) are corrected to 15% O2; this correction is done as a final step in the portion of the equation incorporating CO2 to determine the ammonia concentration at 15% O2 (R). Idaho Power already has equipment in place to measure the ammonia injection rate and SCR inlet and outlet NOx concentrations. The exhaust stack flow can be calculated using a U.S. Environmental Protection Agency (EPA) Method 19 derived approach in Equation 2 as follows:

Equation 2

$$F_{Stack} = \left(\frac{Q_{sd} \times MW_{air}}{385.3}\right)$$

Where:

- Q_{sd} = stack volumetric flow [dscf/hr]
- MW_{air} = molecular weight of air: 29.0 [lb/lb-mol]
- 385.3 = conversion constant [dscf/lb-mol] for natural gas combustion

The stack volumetric flow can be determined from fuel flow, fuel heat content, and oxygen concentration using EPA Method 19 calculations as specified in Equation 3 as follows:

Equation 3

$$Q_{sd} = \frac{F_R \times F_{HV} \times F_{Factor} \times \left(\frac{20.9}{20.9 - C_{O2}}\right)}{10^6}$$

Where:

- F_R = natural gas fuel flow rate [scfh]
- F_{HV} = fuel heating value: 1,020 [Btu/scf]
- F_{Factor} = fuel factor: 8,710 [dscf/MMBtu]

The proposed calculation of stack ammonia concentration includes two correction factors. The CF_{NOx} correction factor is available to account for any instrument error that (all else equal) would cause a difference in readings of NOx concentration between the SCR inlet and outlet CEMS. The CF_{NOx} correction factor could also account for any difference in readings of NOx concentration at the SCR inlet and outlet CEMS caused by stratification of NOx. The CF_{NOx} correction factor does not require reference system data. The CFNH3 correction factor accounts for any differences between the calculated stack ammonia concentration and actual measured concentration. Both correction factors would be determined by performance testing, as proposed in the following sections.

Proposed Initial and Ongoing Performance Testing

Idaho Power has proposed a dynamic limit on ammonia injection using Equation 1 to demonstrate compliance with the limit of 5 ppmvd ammonia slip corrected to 15% O2 on a 24-hr rolling average basis. The use of Equation 1 allows for two static correction factors, CFNOx and CFNH3. These correction factors will be determined from performance testing at Langley Gulch.

CF_{NOx} can be determined by setting ammonia injection to zero and eliminating any function of the SCR, which would theoretically create equal NOx concentrations at the SCR inlet and outlet. Any difference observed with the ammonia injection off would be due to monitor offset or NOx stratification and an according correction factor could be determined. Setting the NOx difference to zero removes any offset between the measurement points that is unrelated to a NOx reduction and the corresponding ammonia consumption. This test scenario may create temporary noncompliance with HRSG stack outlet NOx emission limits because the SCR would not be operating. It is unclear if the testing could be completed quickly enough to avoid an excess emissions event for NOx on a 3-hr rolling average. Therefore, this scenario may not be feasible without additional allowances for varied NOx emissions during performance testing. In lieu of testing with the SCR non-operational, a dynamic set of performance testing at varying combustion turbine loads and ammonia injection rates may be required to determine both the CF_{NOx} and CF_{NH3} correction factors. Essentially, CF_{NOx} is an intercept correction factor and CF_{NH3} is a slope correction factor. Either value could be used to align the calculated slip with the measured slip at a single point such as 5 ppmvd. Use of both correction factors may allow alignment of the calculated slip to the measured slip over a range of slip values.

Ongoing performance testing to determine correction factors will occur on a reoccurring basis. Performance testing analytical equipment, laboratory capabilities, and understanding of underlying engineering principles will undoubtedly grow and develop over time such that performance testing details may warrant ongoing refinement. As such, it is proposed to codify high-level performance testing requirements and frequency in the modified permits but allow for a sperate testing protocol and approval process to determine testing method details prior to each performance test. It is proposed that initial performance testing to determine correction factors be conducted within 180 days of the final permit issuance for the modified PTC and that ongoing testing be conducted at least every five years. This is in alignment with typical timelines for other performance testing at Langley Gulch, including testing required under 40 CFR Part 60 New Source Performance Standards.

The determination of correction factors for Equation 1 will take place after initial performance testing and testing report approval. Consequently, there will a period of time after permit issuance and prior to initial performance testing where Equation 1 will not be able to be used because a value for each correction factor would not yet be determined. During this time a surrogate compliance method is proposed which is simply to use default correction factors of $CF_{NOx} = 0$ and $CF_{NH3} = 1$. Although these correction factors may not result in the most accurate calculation as possible for ammonia slip, it is still more protective of the 5 ppmvd ammonia slip limit than continuation of the static 1.03 gallon per minute ammonia injection rate limit. These initial default correction factors would be superseded upon IDEQ approval of the initial performance testing report and determination of analytically defensible Equation 1 correction factors.

Proposed Ongoing Operational Requirements for SCR Inlet NOx CEMS

Equation 1 requires the SCR inlet NOx concentration in ppm. Langley Gulch is currently equipped with a 0- 150 ppm NOx CEMS range at the SCR inlet but will install a secondary 0-20 ppm NOx CEMS range at the SCR inlet to measure SCR inlet NOx concentration more precisely in the range of typical operating values. The 0-20 ppm CEMS range has been selected to cover all expected NOx concentrations above 60% load and outside of startup and shutdown operation. Only the 0-20 ppm SCR inlet NOx CEMS range would be utilized for determination of compliance with ammonia slip limits. The 0-150 ppm SCR inlet NOx CEMS range will remain for reference only. The level of ongoing compliance requirements for CEMS operation need not be as intensive for the SCR inlet NOx CEMS as for the HRSG stack because it is used for the purposes of compliance with the ammonia slip limit and not New Source Performance Standards (NSPS) or NOx best available control technology (BACT) limits. Routine maintenance and calibration requirements are warranted, as such daily calibrations and relative accuracy test audit (RATA) testing requirements will be applied to the 0-20 ppm range of the SCR inlet NOx CEMS. The 0-20 ppm range SCR inlet CEMS will be calibrated with the same ~10 ppm reference gas used to calibrate the 0-10 ppm HRSG stack CEMS. It is proposed that the same calibration and maintenance requirements will apply to this SCR inlet CEMS as the HRSG stack NOx CEMS, as detailed in Conditions 4.13 and 4.22-26 of the Tier I permit, except without the requirement for:

- Linearities or calibration gas assessments, and
- CEMS certification/recertification requirements including:
  - Cycle time tests,
  - Response time tests, and
  - 7-day drift checks;

of which the procedural requirements are detailed within:

- 40 CFR 60.13(d),
- Performance Specification 2 (PS2) in Appendix B to 40 CFR 60,
- Procedure 1 in Appendix F to 40 CFR 60, or
- 40 CFR Part 75 Subpart C and Appendix A and B.

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Payette County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For HAPs (Hazardous Air Pollutants) Only:

A	=	Use when any one HAP has permitted emissions > 10 T/yr or if the aggregate of all HAPS (Total HAPs) has permitted emissions > 25 T/yr.
SM80	=	Use if a synthetic minor (uncontrolled HAPs emissions are > 10 T/yr or if the aggregate of all uncontrolled HAPs (Total HAPs) emissions are > 25 T/yr and permitted emissions fall below applicable major source thresholds) and the permit sets limits > 8 T/yr of a single HAP or ≥ 20 T/yr of Total HAPs.
SM	=	Use if a synthetic minor (uncontrolled HAPs emissions are > 10 T/yr or if the aggregate of all uncontrolled HAPs (Total HAPs) emissions are > 25 T/yr and permitted emissions fall below applicable major source thresholds) and the permit sets limits < 8 T/yr of a single HAP and/or < 20 T/yr of Total HAPs.
B	=	Use when the potential to emit (i.e. uncontrolled emissions and permitted emissions) are below the 10 and 25 T/yr HAP major source thresholds.
UNK	=	Class is unknown.

For All Other Pollutants:

A	=	Use when permitted emissions of a pollutant are > 100 T/yr.
SM80	=	Use if a synthetic minor for the applicable pollutant (uncontrolled emissions are > 100 T/yr and permitted emissions fall below 100 T/yr) and permitted emissions of the pollutant are ≥ 80 T/yr.
SM	=	Use if a synthetic minor for the applicable pollutant (uncontrolled emissions are > 100 T/yr and permitted emissions fall below 100 T/yr) and permitted emissions of the pollutant are < 80 T/yr.
B	=	Use when the potential to emit (i.e. uncontrolled emissions and permitted emissions) are below the 100 T/yr major source threshold.
UNK	=	Class is unknown.

Table 7 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM_{10}	<100	48.49	**100**	B
$PM_{2.5}$	<100	48.49	**100**	B
SO_2	>100	12.46	**100**	SM
NO_X	>100	87.75	**100**	SM80
CO	>100	278.12	**100**	A
VOC	<100	74.88	**100**	B
HAP (single)	<10	6.04	**10**	B
Total HAPs	<25	10.42	**25**	B

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 .... Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the modified emissions source. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 .... Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Excess Emissions (IDAPA 58.01.01.130-136)

IDAPA 58.01.01.130 .... Startup, Shutdown, Scheduled Maintenance, Safety Measures, Upset and Breakdown

The permittee is subject to the State of Idaho's excess emissions rules. The purpose of these rules is to establish procedures and requirements to be implemented in all excess emissions events and to establish criteria to be applied by the Department in determining whether to take enforcement action to impose penalties for an excess emissions event where the excess emissions are caused by startup, shutdown, scheduled maintenance, upset, or breakdown of any emissions unit or which occur as a direct result of the implementation of any safety measure. The requirements of these rules are ensured by Permit Conditions 2.17 through 2.22.

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625 .... Visible Emissions

The sources of PM emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity. This requirement is assured by Permit Conditions 2.7 through 2.9.

Fuel Burning Equipment – Particulate Matter (IDAPA 58.01.01.675-681)

IDAPA 58.01.01.675 .... Fuel Burning Equipment – Particulate Matter

The permittee is subject to the State of Idaho's Fuel Burning Equipment – Particulate Matter Standards for New Sources. According to this rule, no person shall discharge into the atmosphere from any fuel burning equipment with a maximum rated input of 10 MMBtu/hr or more, and commencing operation on or after October 1, 1979, particulate matter in excess of 0.015 gr/dscf at 3% O_2 for gaseous fuels. This requirement is ensured by Permit Condition 2.11.

Fuel Sulfur Content – Sulfur Dioxide (IDAPA 58.01.01.725)

IDAPA 58.01.01.725.. Fuel Burning Equipment – Particulate Matter
The permittee is subject to the State of Idaho's Rules for Sulfur Content of Fuels. According to this rule, no person shall sell, distribute, use, or make available for use, any distillate fuel oil containing more than 0.3% sulfur by weight for ASTM Grade 1 fuel oil and 0.5% by weight for ASTM Grade 2 fuel oil. This requirement is ensured by Permit Conditions 2.12 and 2.13.

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

IDAPA 58.01.01.301.. Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility have a potential to emit greater than 100 tons per year for CO as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, this facility is classified as a major facility, as defined in IDAPA 58.01.01.008.10.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 .... Prevention of Significant Deterioration of Air Quality

Because the proposed facility is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input (designated facility) which has the potential to emit 100 tons per year or more of CO, it is classified as a major stationary source as defined in §52.21(b)(1)(i)(a) and in accordance with IDAPA 58.01.01.205.01.

The project emissions increases associated with this project do not exceed PSD significance thresholds; therefore, this project does not constitute a PSD Major Modification and is not subject to PSD permitting requirements.

NSPS Applicability (40 CFR 60)

Because the facility has two petroleum storage tanks and a gas-fired combustion turbine operating in combined cycle, the following NSPS subparts may appear to apply, but do not upon closer inspection.

- 40 CFR 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

  According to §60.4305(b), stationary gas turbines that are subject to Subpart KKKK are exempt from the requirements of Subpart Db.

- 40 CFR 60, Subpart Kb - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

  According to §60.110b, the requirements of this subpart apply to storage vessels with a capacity of greater than or equal to 75 cubic meters that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Since each petroleum storage tank located at the facility has a capacity of only 250 gallons (0.946 m3), the requirements of Subpart Kb do not apply.

- 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

  According to §60.4305(b), stationary gas turbines that are subject to Subpart KKKK are exempt from the requirements of Subpart GG.

- 40 CFR 60, Subpart TTTT – Standards of Performance for Electric Utility Generating Units

  According to §60.5509, the requirements of this subpart apply to any steam generating unit, IGCC, or combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 and that has a base load rating greater than 250 MMBtu/hr of fossil fuel and serves a generator of generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

The combustion turbine was constructed in 2010; that is, it is an existing source. Although the combustion turbine will be modified by this permitting action at a date after the July 18, 2014, §60.5509(b)(7) specifies that if the modification results in an hourly increase in CO_2 emissions of 10% or less then the unit is not subject to the requirements of Subpart TTTT. In effect, it remains an existing source.

In addition, because the facility has a diesel-fired emergency pump house engine, a diesel-fired emergency engine, and a diesel-fired fire pump, it is subject to the following NSPS subpart. The applicability of this subpart is not altered by this permitting action.

- 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Finally, because the facility has a combustion turbine operating in combined cycle it is subject to the following NSPS subpart. The applicability of this subpart may be altered by this permitting action; therefore, a full breakdown is provided below.

- 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

40 CFR 60, Subpart KKKK................................ Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

§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. The subpart also applies to the HRSG and duct burners.

(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 turbine is not subject to the requirements of Subpart GG and Db.

§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.

§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 (NO_X)?

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

The permittee shall comply with the emission limits for NO_X specified in Table 1. This requirement is ensured by Permit Condition 3.8. The applicable emission limit is 15 ppm at 15% 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 and duct burners are subject to BACT emissions limits for NO_X that assure compliance with §60.4320(a). The BACT emission limits are listed in Condition 4.2 of the T1-2018.0023, issued October 19, 2018.

(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 NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

The combustion turbine burns only natural gas, therefore §60.4325 is not applicable.

§60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) <u>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.</u>

(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) <u>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</u>

The facility is limited by Permit Condition 3.19 to the use of pipeline quality natural gas meeting a standard of 0.5 grains total sulfur per 100 standard cubic feet. This limit results in an SO_2 emission factor of 0.00143 lb SO_2/MMBtu – less than the limit given in paragraph (a)(2) above. Therefore, compliance with Permit Condition 3.19 ensures compliance with this requirement. Regardless, this requirement is ensured explicitly by Permit Condition 3.9.

(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 non-continental 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.

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

(a) <u>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.</u>

The facility will continue to operate the combustion turbine and air pollution control equipment in a manner consistent with good air pollution control practices. This requirement is ensured by Permit Condition 3.18.

(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.

§60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?
The facility does not use water or steam injection.

§60.4340 How do I demonstrate continuous compliance for NO_X 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) <u>As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:</u>

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

As an alternative to conducting annual performance tests, the facility operates a continuous emission monitoring system. This requirement is ensured by Permit Condition 3.15.

(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?

<u>If the option to use a NO_X CEMS is chosen:</u>

(a) <u>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.</u>

(b) <u>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</u>

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.

The facility will install, calibrate, maintain, and operate its NO_X CEMS in a manner consistent with the requirements of §60.4345. These requirements are ensured by Permit Condition 3.27.

§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 NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X 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:

$$P = (Pe)_t + (Pe)_e + Ps + Po \quad (Eq. 2)$$

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

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

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 $3.413 \times 10_6$ = 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:

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

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).

The facility will comply with the requirements of §60.4350, as ensured by Permit Condition 3.28.

§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:

(b) 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.
(c) (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.
(d) <u>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.</u>
The facility is subject to part 75 requirements and permit condition 9.10 of the facility's Tier 1 permit requires them to measure NO_X emissions for the combustion turbine in accordance with 40 CFR 75.19. The facility will comply with this requirement by complying with permit condition 9.10 of their T1 permit.

§60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?
<u>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.</u>
The facility will continue to comply with the requirements of §60.4360. These requirements are ensured by Permit Condition 3.31.

§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 non-continental 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 non-continental 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 non-continental 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 non-continental 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 non-continental 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.

If the fuel combusted in the CT is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu) heat input, they may elect not to monitor the total sulfur content of the fuel and shall instead choose one of the two options provided in §60.4365(a) or (b). This requirement is ensured by Permit Condition 3.31.

§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.

The requirements of §60.4370 are ensured by Permit Condition 3.32.

§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.

The facility is required to continuously monitor emissions and periodically determine fuel sulfur content, and perform annual performance tests (§60.4415(a)), therefore it will comply with the requirements of §60.4375(a), and (b). These requirements are ensured by Permit Conditions 3.39.

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

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.

The facility uses continuous emissions monitoring for NO_X, therefore the requirements of §60.4380 apply. These requirements are ensured by Permit Condition 3.40.

(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 SO_2?

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.

The facility monitors fuel sulfur content of gaseous fuels, but does not combust fuel oil in the CT and duct burners, therefore the requirements of §60.4385(a) and (b) apply. These requirements are ensured by Permit Condition 3.41.

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

The facility does not operate an emergency combustion turbine or a research and development turbine, therefore the requirements of §60.4390 do not apply.

§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.

This requirement is ensured by Permit Condition 3.42.

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

(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:

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

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.

The initial NO_X performance testing has already been completed, and the facility, in accordance with §60.4340, has opted to use a NO_X CEMS to demonstrate continuous compliance in place of annual performance testing.

§60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-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.

The facility has chosen to install and certify a NO_X –diluent CEMS, however the initial certification has already been completed.

§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.

The facility continuously monitors the ammonia injection rate of their selective catalytic reduction system; therefore, they will continuously monitor the ammonia injection rate during each run of the initial performance test. This requirement is ensured by Permit Condition 3.37.

§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:

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

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.

The facility shall conduct SO_2 performance tests on an annual basis in accordance with §60.4415. This requirement is ensured by Permit Condition 3.38.

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).

NESHAP Applicability (40 CFR 61)

The facility is not subject to any NESHAP requirements in 40 CFR 61.

MACT/GACT Applicability (40 CFR 63)

The facility is not subject to any MACT standards in 40 CFR Part 63; however Subpart YYYY may appear to apply. Upon closer inspection, §63.6080 states that the requirements of Subpart YYYY apply to each stationary combustion turbine located at a major source of HAP emissions. Since the facility is not a major source of HAP emissions, it is not subject to Subpart YYYY.

Permit Conditions Review

This section describes the permit conditions for this initial permit or only those permit conditions that have been added, revised, modified or deleted as a result of this permitting action.

Revised Permit Condition 3.10

This permit condition was revised to correct the PM_{10} emission limit.

Modified Permit Condition 3.21

This permit condition was modified to add the requirement to install, calibrate, operate, and maintain a NOx CEMS, to be used to gather data necessary for ammonia slip monitoring.

Modified Permit Condition 3.22

This permit condition was modified from providing a single ammonia injection flow rate to establishing the series of equations to be used to determine optimal ammonia slip.

Modified Permit Condition 3.35

This permit condition was modified from monitoring and recording the ammonia injection flow rate, to calculating and recording the ammonia slip on an hourly operation basis.

Modified Permit Condition 3.37

This permit condition was modified to change the reference from ammonia injection rate monitoring to calculated ammonia slip recordkeeping.

PUBLIC REVIEW

Public Comment Opportunity

Because this permitting action does not authorize an increase in emissions, an opportunity for public comment period was not required or provided in accordance with IDAPA 58.01.01.209.04 or IDAPA 58.01.01.404.04.

APPENDIX A – EMISSIONS INVENTORIES

APPENDIX B – FACILITY DRAFT COMMENTS

The following comments were received from the facility on October 5, 2023:

Facility Comment: Can we use 30 days rather than 60 days for the ammonia slip testing protocol.

DEQ Response: DEQ granted this request, amending permit condition 3.22 to only require that the ammonia slip testing protocols be submitted 30 days prior to the test date.

APPENDIX C – PROCESSING FEE